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

IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN	**CASE NO.:** NEPR-AP-2023-0004 **SUBJECT**: Memorandum of Law in Support of Request for Confidential Treatment of Revised 2025 IRP and Submission of Public Version and Confidential Version of Revised 2025 IRP

MEMORANDUM OF LAW IN SUPPORT OF REQUEST OF CONFIDENTIAL TREATMENT OF REVISED 2025 IRP[1] AND SUBMISSION OF PUBLIC VERSION AND CONFIDENTIAL VERSION OF REVISED 2025 IRP

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

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

I. Introduction and Procedural Background

On May 13, 2025, the Energy Bureau issued a Resolution and Order setting October 17, 2025, as the date for LUMA to submit the 2025 Integrated Resource Plan ("2025 IRP"), specifically the primary sections of Regulation 9021 that require resource plan development, selection of a Preferred Resource Plan, and reporting on existing and planned transmission and distribution system elements ("May 13th Order"). Further, the Energy Bureau provided two additional filing deadlines: (a) November 21, 2025, to file the portion of the requirements that commands LUMA to test the Preferred Resource Plan to determine any implications it may have

[1] The revised version differs from the version filed on October 17, 2025, in that it addresses some grammatical errors and formatting issues, and revises the data presented in Tables 66, 67, and 68, specifically the values in the second column labeled "PR100 Cost Scaling Factor." It also revisits some of the confidential designations originally made.

on the transmission and distribution system; and (b) "shortly thereafter" November 21, 2025 to file the "Supplemental" modeling runs identified in the May 13th Order.

On October 17, 2025, LUMA filed a *Motion Submitting 2025 IRP and Request for Confidential Treatment*. Therein, LUMA submitted the 2025 IRP recommending that the Energy Bureau approve Resource Plan Hybrid A as LUMA's Preferred Resource Plan. Resource Plan Hybrid A represents a balanced, cost-effective path to meeting Puerto Rico's energy needs, reflecting current expectations for fuel and technology costs. In compliance with the May 13th Order, LUMA filed the 2025 IRP as *Exhibit 1* and the workpapers and models relied on in developing the 2025 IRP as *Exhibit 2*.

LUMA respectfully submits that the 2025 IRP, and the workpapers and models relied upon in developing the 2025 IRP, contain confidential information that garners protection from public disclosure pursuant to applicable law and regulations, as will be expounded upon below. Thus, LUMA is submitting a revised, redacted version of the 2025 IRP, along with the workpapers and models relied on in developing the 2025 IRP, for public disclosure as *Exhibits 1 and 2* to this Motion. Accordingly, pursuant to this Energy Bureau's Policy on Confidential Information, LUMA hereby submits the corresponding memorandum of law stating the legal basis for the request to treat certain portions of the revised version of the 2025 IRP and the workpapers and models relied on in developing the 2025 IRP confidentially.

II. Applicable Laws and Regulations for submitting information confidentially before the Energy Bureau

Section 6.15 of Act 57-2014 regulates the management of confidential information filed before this Energy Bureau. It provides, in pertinent part, that: "[i]f any person who is required to submit information to the Energy [Bureau] believes that the information to be submitted has any confidentiality privilege, such person may request the Commission to treat such information as

such . . . . " 22 LPRA § 1054n (2025). If the Energy Bureau determines, after appropriate evaluation, that the information should be protected, "it shall grant such protection in a manner that least affects the public interest, transparency, and the rights of the parties involved in the administrative procedure in which the allegedly confidential document is submitted." *Id*., Section 6.15(a).

In connection with the duties of electric power service companies, Section 1.10(i) of Act 17-2019[2] further provide that electric power service companies shall submit information requested by customers, except for: (i) confidential information in accordance with the Rules of Evidence of Puerto Rico. 22 LPRA § 1141i (2025).

Access to the confidential information shall be provided "only to the lawyers and external consultants involved in the administrative process after the execution of a confidentiality agreement." Section 6.15(b) of Act 57-2014, 22 LPRA § 1054n (2025). Finally, Act 57-2014 provides that this Energy Bureau "shall keep the documents submitted for its consideration out of public reach only in exceptional cases. In these cases, the information shall be duly safeguarded and delivered exclusively to the personnel of the [Energy Bureau] who needs to know such information under nondisclosure agreements. However, the [Energy Bureau] shall direct that a non-confidential copy be furnished for public review". *Id*., Section 6.15(c).

Moreover, the Energy Bureau's Policy on Confidential Information details the procedures that a party should follow to request that a document or portion thereof be afforded confidential treatment. In essence, the Energy Bureau's Policy on Confidential Information requires identification of the confidential information and the filing of a memorandum of law, "no later than ten (10) days after filing of the Confidential Information", explaining the legal basis and

[2] Known as the "Puerto Rico Energy Public Policy Act" (hereinafter, "Act 17-2019").

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

The Energy Bureau's Policy on Confidential Information also states the following with regard to access to Validated Confidential Information:

> 1. Trade Secret Information
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> Any document designated by the [Energy Bureau] as Validated Confidential Information on the grounds that it is a trade secret pursuant to Act 80-2011 may only be accessed by the Producing Party and the [Energy Bureau], unless otherwise set forth by the [Energy Bureau] or any competent court.
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> 2. Critical Energy Infrastructure Information ("CEII")
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> The information designated by the [Energy Bureau] as Validated Confidential Information on the ground of being CEII may be accessed by the parties' authorized representatives only after they have executed and delivered the Non-Disclosure Agreement.
>
> Those authorized representatives who have signed the Non-Disclosure Agreement may only review the documents validated as CEII at the [Energy Bureau] or the Producing Party's offices. During the review, the authorized representatives may not copy or disseminate the reviewed information and may bring no recording device to the viewing room.

Id., Section D (on Access to Validated Confidential Information).

Relatedly, Energy Bureau Regulation No. 8543, *Regulation on Adjudicative, Notice of Noncompliance, Rate Review, and Investigation Proceedings*, includes a provision for filing

confidential information in adjudicatory proceedings before this honorable Energy Bureau. To wit, Section 1.15 provides that, "a person has the duty to disclose information to the [Energy Bureau] considered to be privileged pursuant to the Rules of Evidence, said person shall identify the allegedly privileged information, request the [Energy Bureau] the protection of said information, and provide supportive arguments, in writing, for a claim of information of privileged nature. The [Energy Bureau] shall evaluate the petition and, if it understands [that] the material merits protection, proceed accordingly to . . . Article 6.15 of Act No. 57-2015, as amended."

III. Legal Basis and Arguments in Support of Confidentiality

A. Trade Secret

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

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

Id. § 4132, Section 3 of Act 80-2011. (Emphasis added).

Trade secrets include, but are not limited to, processes, methods and mechanisms, manufacturing processes, formulas, projects or patterns to develop machinery and lists of specialized clients that may afford an advantage to a competitor. *See* Statement of Motives, Act 80-2011. As explained in the Statement of Motives of Act 80-2011, protected trade secrets include any information bearing commercial or industrial value that the owner reasonably protects from disclosure. *Id. See also* Sections 4 (ix) and (x) of the *Puerto Rico Open Government Data Act*, Act 122-2019, 3 LPRA § 9894 (exempting the following from public disclosure: (1) commercial or

financial information whose disclosure will cause competitive harm and (2) trade secrets protected by a contract, statute, or judicial decision).

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

Pursuant to Act 80-2011 and the applicable legal standards governing the protection of trade secrets and proprietary information, LUMA respectfully requests confidential treatment of the fixed and variable operations maintenance costs included in *Table 47: Cost Information on PREPA-Owned Resources* of the revised version of the 2025 IRP in *Exhibit 1*. These fixed and variable operations maintenance costs constitute trade secrets under Section 3 of Act 80-2011, as they possess independent economic value and provide a business advantage by not being generally known or readily accessible to competitors or the public. Moreover, reasonable measures have been taken to maintain the confidentiality of this information, consistent with statutory requirements. Disclosure of these proprietary fixed and variable operations maintenance costs would risk causing competitive harm to LUMA and undermining the public policy favoring the protection of commercially valuable confidential information. Accordingly, LUMA requests that the Energy Bureau grant confidential treatment to the fixed and variable operations and

maintenance costs included in *Table 47: Cost Information on PREPA-Owned Resources* of the revised version of the 2025 IRP, to safeguard the integrity of trade secrets and ensure compliance with the statutory protections afforded under Puerto Rico law.

B. Third-Party Proprietary Information

As mentioned above, Section 4(x) of the *Puerto Rico Open Government Data Act*, Act 122-2019, exempt from public disclosure commercial or financial information whose disclosure will cause competitive harm. 3 LPRA § 9894. The portions of the revised version of the 2025 IRP identified in Section IV of the present Motion contain or reference proprietary coal values, heat rates, cost information, and PLEXOS© formulas and pivot tables belonging to third parties. These coal values, heat rates, and cost information constitute commercial or financial information within Section 4(x) of Act 122-2019, as they possess independent economic value and provide a business advantage by virtue of not being generally known or readily accessible to competitors or the public. Moreover, reasonable measures have been taken to maintain the confidentiality of this information, consistent with statutory requirements. Disclosure of these coal values, heat rates, cost information, and PLEXOS© formulas and pivot tables would risk causing competitive harm to the third party and undermining the public policy favoring the protection of commercially valuable confidential information. Therefore, LUMA requests that the Energy Bureau grant confidential treatment to these coal values, heat rates, cost information, and PLEXOS© formulas and pivot tables proprietary to third parties to ensure compliance with the statutory protections afforded under Puerto Rico law.

C. Critical Energy Infrastructure Information

Act 40-2024, better known as the *Commonwealth of Puerto Rico Cybersecurity Act*, defines "Critical Infrastructure" as those "services, systems, resources, and essential assets, whether physical

or virtual, the incapacity or destruction of which would have a debilitating impact on Puerto Rico's cybersecurity, health, economy, or any combination thereof." 3 LPRA § 10124(p) (2024). Generally, CEII or critical infrastructure information is generally exempted from public disclosure because it involves assets and information, posing public security, economic, health, and safety risks. Federal Regulations on CEII, particularly, 18 C.F.R. § 388.113, state that:

> Critical energy infrastructure information means specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
>
> (i) Relates details about the production, generation, transportation, transmission, or distribution of energy;
> (ii) Could be useful to a person in planning an attack on critical infrastructure;
> (iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
> (iv) Does not simply give the general location of the critical infrastructure.

Id.

Additionally, "[c]ritical electric infrastructure means a system or asset of the bulk-power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters." ***Id.*** Finally, "[c]ritical infrastructure means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters." *Id.*

The Critical Infrastructure Information Act of 2002, 6 U.S.C. §§ 671-674 (2020), part of the Homeland Security Act of 2002, protects critical infrastructure information ("CII").[3] CII is

[3] Regarding protection of voluntary disclosures of critical infrastructure information, 6 U.S.C. § 673, provides in pertinent part, that CII:

> (A) shall be exempt from disclosure under the Freedom of Information Act;
> (B) shall not be subject to any agency rules or judicial doctrine regarding ex parte communications with a decision making official;
> (C) shall not, without the written consent of the person or entity submitting such information, be used

defined as "information not customarily in the public domain and related to the security of critical infrastructure or protected systems...." 6 U.S.C. § 671 (3).[4]

The portions of the revised version of the 2025 IRP identified in Section IV of the present Motion include CEII, because it contains single-line diagrams that qualify as CEII. They contain information on the engineering and design of critical infrastructure, as existing and proposed, relating to the transmission of electricity, which is provided in sufficient detail that it could

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directly by such agency, any other Federal, State, or local authority, or any third party, in any civil action arising under Federal or State law if such information is submitted in good faith;
(D) shall not, without the written consent of the person or entity submitting such information, be used or disclosed by any officer or employee of the United States for purposes other than the purposes of this part, except—
(i) in furtherance of an investigation or the prosecution of a criminal act; or
(ii) when disclosure of the information would be--
(I) to either House of Congress, or to the extent of matter within its jurisdiction, any committee or subcommittee thereof, any joint committee thereof or subcommittee of any such joint committee; or
(II) to the Comptroller General, or any authorized representative of the Comptroller General, in the course of the performance of the duties of the Government Accountability Office;
(E) shall not, be provided to a State or local government or government agency; of information or records;
(i) be made available pursuant to any State or local law requiring disclosure of information or records;
(ii) otherwise be disclosed or distributed to any party by said State or local government or government agency without the written consent of the person or entity submitting such information; or
(iii) be used other than for the purpose of protecting critical Infrastructure or protected systems, or in furtherance of an investigation or the prosecution of a criminal act.
(F) does not constitute a waiver of any applicable privilege or protection provided under law, such as trade secret protection.

[4] CII includes the following types of information:

(A) actual, potential, or threatened interference with, attack on, compromise of, or incapacitation of critical infrastructure or protected systems by either physical or computer-based attack or other similar conduct (including the misuse of or unauthorized access to all types of communications and data transmission systems) that violates Federal, State, or local law, harms interstate commerce of the United States, or threatens public health or safety;
(B) the ability of any critical infrastructure or protected system to resist such interference, compromise, or incapacitation, including any planned or past assessment, projection, or estimate of the vulnerability of critical infrastructure or a protected system, including security testing, risk evaluation thereto, risk management planning, or risk audit; or
(C) any planned or past operational problem or solution regarding critical infrastructure or protected systems, including repair, recovery, construction, insurance, or continuity, to the extent it is related to such interference, compromise, or incapacitation.

potentially be helpful to a person planning an attack on this or other energy infrastructure facilities interconnected with or served by this facility and equipment. In addition, the portions of the revised version of the 2025 IRP that have been identified in Section IV qualify as CEII because each of these documents contains the express coordinates for power transmission and distribution facilities (18 C.F.R. § 388.113(iv)), and these specific coordinates could potentially be helpful to a person planning an attack on the energy facilities. The information identified as confidential in this paragraph is not common knowledge, is not made publicly available, and if disclosed to the public, will expose key assets to security vulnerabilities or attacks by people seeking to cause harm to the systems. Therefore, it is in the public interest to keep the information confidential. Confidential designation is a reasonable and necessary measure to protect critical infrastructure from attacks and to enable LUMA to leverage information without external threats, *see e.g.,* 6 U.S.C §§ 671-674; 18 C.F.R. §388.113 (2020), and the Energy Bureau's Policy on Confidential Information.

In several proceedings, this Energy Bureau has considered and granted requests by PREPA to submit CEII under seal of confidentiality.[5] In at least two proceedings on Data Security[6] and Physical Security,[7] this Energy Bureau, motu proprio, has conducted proceedings confidentially, thereby recognizing the need to protect CEII from public disclosure.

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[5] *See e.g., In re Review of LUMA's System Operation Principles,* NEPR-MI-2021-0001 (Resolution and Order of May 3, 2021); *In re Review of the Puerto Rico Power Authority's System Remediation Plan*, NEPR-MI-2020-0019 (order of April 23, 2021); *In re Review of LUMA's Initial Budgets*, NEPR-MI-2021-0004 (order of April 21, 2021); *In re Implementation of Puerto Rico Electric Power Authority Integrated Resource Plan and Modified Action Plan,* NEPR MI 2020-0012 (Resolution of January 7, 2021, granting partial confidential designation of information submitted by PREPA as CEII); *In re Optimization Proceeding of Minigrid Transmission and Distribution Investments*, NEPR MI 2020-0016 (where PREPA filed documents under seal of confidentiality invoking, among others, that a filing included confidential information and CEII); *In re Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*, CEPR-AP-2018-0001 (Resolution and Order of July 3, 2019 granting confidential designated and request made by PREPA that included trade secrets and CEII) *but see* Resolution and Order of February 12, 2021 reversing in part, grant of confidential designation).

[6] *In re Review of the Puerto Rico Electric Power Authority Data Security Plan,* NEPR-MI-2020-0017.

[7] *In re Review of the Puerto Rico Electric Power Authority Physical Security Plan,* NEPR-MI-2020-0018.

Additionally, this Energy Bureau has granted requests by LUMA to protect CEII in connection with LUMA's System Operation Principles. *See* Resolution and Order of May 3, 2021, table 2 on page 4, Case No. NEPR-MI-2021-0001 (granting protection to CEII included in LUMA's Responses to Requests for Information). Similarly, in the proceedings on LUMA's proposed Initial Budgets and System Remediation Plan, this Energy Bureau granted confidential designation to several portions of LUMA's Initial Budgets and Responses to Requests for Information. *See* Resolution and Order of April 22, 2021, on Initial Budgets, table 2 on pages 3-4, and Resolution and Order of April 22, 2021, on Responses to Requests for Information, table 2 on pages 8-10, Case No. NEPR-MI-2021-0004; Resolution and Order of April 23, 2021, on Confidential Designation of Portions of LUMA's System Remediation Plan, table 2 on page 5, and Resolution and Order of May 6, 2021, on Confidential Designation of Portions of LUMA's Responses to Requests for Information on System Remediation Plan, table 2 at pages 7-9, Case No. NEPR-MI-2020-0019.

IV. Identification of Confidential Information

In compliance with the Energy Bureau's Policy on Confidential Information, CEPR-MI-2016-0009, a table summarizing the hallmarks of this request for confidential treatment is hereby included.

Document	**Name**	**Pages in which Confidential Information is Found**	**Summary of Legal Basis for Confidentiality Protection**	**Date Filed**
Exhibit 1	Table 4: Summary Description of the Current PREPA Generation Fleet	Page 28	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	Table 46: Technical Data of Independent Power Producer Resources	Page 165	Third-Party Proprietary Information	October 29, 2025
	Table 47: Cost Information on PREPA-Owned Resources	Pages 166 and 167	Third-Party Proprietary Information	October 29, 2025
	Table 48: Cost Information of Independent Power Producer Resources	Pages 167 and 168	Trade Secret, Act 80-2011, 10 LPRA §§ 4131-4144	October 29, 2025
	Table 53: Non-tranche Projects	Pages 186 and 187	Third-Party Proprietary Information	October 29, 2025
	Table 55: Tranche 2 Projects	Page 188	Third-Party Proprietary Information	October 29, 2025
	Table 56: Tranche 4 Projects	Page 188	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	Table 103: Preferred Resource Plan Annual Emissions by Fuel (thousand tons CO2eq)	Page 280	Third-Party Proprietary Information	October 29, 2025
	Table 104: Preferred Resource Plan Annual Fuel Consumption by Fuel Type (BBtu)	Page 280	Third-Party Proprietary Information	October 29, 2025
	Appendix 1: Figure 1: Transmission System Map	Page 39	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	Appendix 1: Table 26: 2025 Critical Performance Criteria Violations: N-1 Thermal Overloads	Page 78	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	Appendix 1: Table 27: 2025 Critical Performance Criteria Violations: N-1 Voltage Violations	Page 79	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	Appendix 1: Figure 19: Puerto Rico Electric Transmission System	Page 81	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	Appendix 2: Table 32: Contracted Utility-Scale Solar Projects	Pages 106 and 107	Third-Party Proprietary Information	October 29, 2025
	Appendix 2: Table 33: Summary of Contracted and Modeled BESS Projects	Pages 107 and 108	Third-Party Proprietary Information	October 29, 2025
	Appendix 3: Table 36: PPOA Project Overview	Pages 121 and 122	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 68: Scenario 1 Annual Emissions by resource (tonCO2eq)	Page 288	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 69: Scenario 1 Annual Fuel consumption by Fuel Type (BBtu)	Page 289	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	Appendix 6: Table 74: Scenario 2 Annual Emissions by resource (tonCO2eq)	Page 295	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 75: Scenario 2 Annual Fuel consumption by Fuel Type (BBtu)	Page 295	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 80: Scenario 3 Annual Emissions by resource (tonCO2eq)	Page 301	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 81: Scenario 3 Annual Fuel consumption by Fuel Type (BBtu)	Page 302	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 86: Scenario 4 Annual Emissions by resource (tonCO2eq)	Page 306	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 87: Scenario 4 Annual Fuel consumption by Fuel Type (BBtu)	Page 307	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	Appendix 6: Table 92: Scenario 5 Annual Emissions by resource (tonCO2eq)	Page 314	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 93: Scenario 5 Annual Fuel consumption by Fuel Type (BBtu)	Page 314	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 98: Scenario 6 Annual Emissions by resource (tonCO2eq)	Page 321	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 99: Scenario 6 Annual Fuel consumption by Fuel Type (BBtu)	Page 321	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 104: Scenario 7 Annual Emissions by resource (tonCO2eq)	Page 326	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 105: Scenario 7 Annual Fuel consumption by Fuel Type (BBtu)	Page 326	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	Appendix 6: Table 110: Scenario 8 Annual Emissions by resource (tonCO2eq)	Page 331	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 111: Scenario 8 Annual Fuel consumption by Fuel Type (BBtu)	Page 332	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 116: Scenario 9 Annual Emissions by resource (tonCO2eq)	Page 337	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 117: Scenario 9 Annual Fuel consumption by Fuel Type (BBtu)	Page 338	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 122: Scenario 10 Annual Emissions by resource (tonCO2eq)	Page 344	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 123: Scenario 10 Annual Fuel consumption by Fuel Type (BBtu)	Page 344	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	Appendix 6: Table 128: Scenario 11 Annual Emissions by resource (tonCO2eq)	Page 351	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 129: Scenario 11 Annual Fuel consumption by Fuel Type (BBtu)	Page 351	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 134: Scenario 12 Annual Emissions by resource (tonCO2eq)	Page 356	Third-Party Proprietary Information	October 29, 2025
	Appendix 6: Table 135: Scenario 12 Annual Fuel consumption by Fuel Type (BBtu)	Pages 356-357	Third-Party Proprietary Information	October 29, 2025
Exhibit 2	2.02_PBUT4_Grid Automation_FY26	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	30059 - Distribution Automation Initial SOW 09122023 - signed	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
			U.S.C. §§ 671-674	
	Area Plans and Substations Capacity Constraints Sep 2025	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	Feeder Voltage and Loading Violations 2Sept2025	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	IRP Feeder Substation Voltage and Thermal IRP Supporting Document	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	LUMA Energy Substations ABFE's	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	LUMA Substations Data October 2025	Entire File		October 29, 2025
	Planning Substations Sites and Flood Hazard IRP	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	Resumen_Métricas_BT_ Sep2025	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	Voltage Tickets Per Customer Served Heat Map	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	Exhibit 1_System Improvements Plan _Final	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	LUMA Energy Transmission System	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	October 29, 2025
	06.06.25 CONFIDENTIAL LUMA Request to Confirm Data for Environmental Analysis-IRP	Entire File	Third-Party Proprietary Information	October 29, 2025
	25.05.28_CONFIDENTIAL LUMA's Request to Genera to Confirm Data for Enviromental Analysis-signed	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL LUMA DR Potential Study Report_final_with transmittal letter	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL LUMA LF Improve 3 Rpt Addendum_FINAL_2025-01-15	Entire File	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	CONFIDENTIAL LUMA LF Improvement 3 Report_2024-04-18 - FINAL	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL Grid Defection Calculations	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL Final_Input_Assumptions_Parameters_and_Costs_10.03.2025	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_IRP Fuel Workpaper	Coal Forced Outage Rate (%) and Average Rates (years)	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL SupDoc_IRP Forecast	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL LUMA PLEXOS Database	Entire File	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	09.22_Portfolio Flex A ASAP P2&Batt Eff	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .08 IRP Summary Results_Sc1_Battery Efficiency Changes	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .08 IRP Summary Results_Sc12_Battery Efficiency Changes	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc 11	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc 8	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc1 ASAP P2 and Batt Eff	Entire File	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc1	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc10	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc12 ASAP P2 & Batt Eff	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc12	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc2	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.09 .23 IRP Summary Results_Sc3	Entire File	Third-Party Proprietary Information	October 29, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	CONFIDENTIAL_25.09.23 IRP Summary Results_Sc4	Entire File	Third-Party Proprietary Information	October 29, 2025
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	CONFIDENTIAL_25.09.23 IRP Summary Results_Sc9	Entire File	Third-Party Proprietary Information	October 29, 2025
	CONFIDENTIAL_25.10.03 IRP Summary Results_Sc1_HYBRID A - PRP	Entire File	Third-Party Proprietary Information	October 29, 2025

WHEREFORE, LUMA respectfully requests that the Energy Bureau **take notice** of the aforementioned; and **approve the request for confidential treatment** of the information submitted in *Exhibits 1 and 2* to this Motion.

WE HEREBY CERTIFY that this Motion was filed using the electronic filing system of this Energy Bureau and that electronic copies of this Motion will be notified to the Puerto Rico Electric Power Authority: lionel.santa@prepa.pr.gov and through its attorneys of record Mirelis Valle-Cancel, mvalle@gmlex.net; and Alexis G. Rivera Medina, arivera@gmlex.net; and Genera PR, LLC, through its attorney of record Luis R. Román Negrón, lrn@roman-negrom.com.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, on October 29, 2025.

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Exhibit 1

2025 Integrated Resource Plan

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 the operation of Puerto Rico's transmission and distribution (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:

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

- Building a cleaner energy future by reducing carbon emissions.
- Optimizing technology diversity.
- Enabling decentralized generation.
- 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% 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), 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 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 technical 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 Resource Plan Hybrid A 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
PJM	Pennsylvania- New Jersey- Maryland
PM	particulate matter
PPOA	power purchase and operating agreement
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
R100	renewable diesel
R&O	resolution and order

TERM & ACRONYMS	DEFINITION
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
WTE	waste-to-energy

Section 1:

Introduction and Summary of Conclusions

1.0 Introduction and Summary of Conclusions

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, in accordance with the Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement dated June 22, 2020 ("T&D OMA"), 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).[3] 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

[2] See Puerto Rico Energy Bureau case Number NEPR-MI-2020-0019: In re: Review of the Puerto Rico Electric Power Authority's System Remediation Plan.

[3] Under the T&D OMA, LUMA is tasked with preparing a proposed IRP for review and approval by the Energy Bureau. See T&D OMA, Section 5.6(f), p. 67. "The proposed IRP shall be designed in accordance with Applicable Law and a manner to ensure that, if approved by the Energy Bureau and subject to the assumptions specified therein, LUMA can provide safe and adequate transmission and distribution service at the lowest reasonable rates consistent with budgetary and T&D System requirements, and with sound fiscal operating practices." Id.

made progress in improving overall reliability and carrying out key repairs[4], the system remains vulnerable and requires significant remediation.

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 seven 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 (PSS®e analysis)[5]. The Energy Bureau directed that the PSS®e analysis of the Preferred Resource Plan (PRP) be filed on November 21, 2025. For the October 17, 2025, filing, LUMA was ordered to complete modeling of the Primary[6] 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] 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

[5] The PSS®e 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.

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

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Table 2: Summary Description of Primary 12 Scenarios[7]

Scenario	Scenario Description	Load	PV & UBESS CapEx	Natural Gas Plant CapEx + Bio Conversion Costs[8]	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 PSS®e 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.

[7] As further discussed or defined in this IRP, as used in this table, the term PV refers to photovoltaic systems, the term UBESS refers to utility-scale battery energy storage systems, the term CapEx refers to capital expenditures, the term DBESS refers to distributed battery energy storage systems, the term NGCC refers to natural gas combined cycle, and the term RPS refers to renewable portfolio standards.

[8] 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.

Table 3: Summary Description of Five Supplemental Scenarios

Scenario	Scenario Description	Load	PV & UBESS CapEx	Natural Gas Plant CapEx + Bio Conversion Costs[9]	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)
Heavy Fuel Oil	1,532	1,280	29%	58
Coal				
Natural Gas	2,145	340	26%	19
Diesel	1,200	228	48%	34

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

[9] 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 procurement details. 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. In addition, there were resource additions dictated prior to the preparation of the 2025 IRP.

LUMA found that 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 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 the primary goals of the 2025 IRP was to improve the reliability of the generation fleet with the 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.

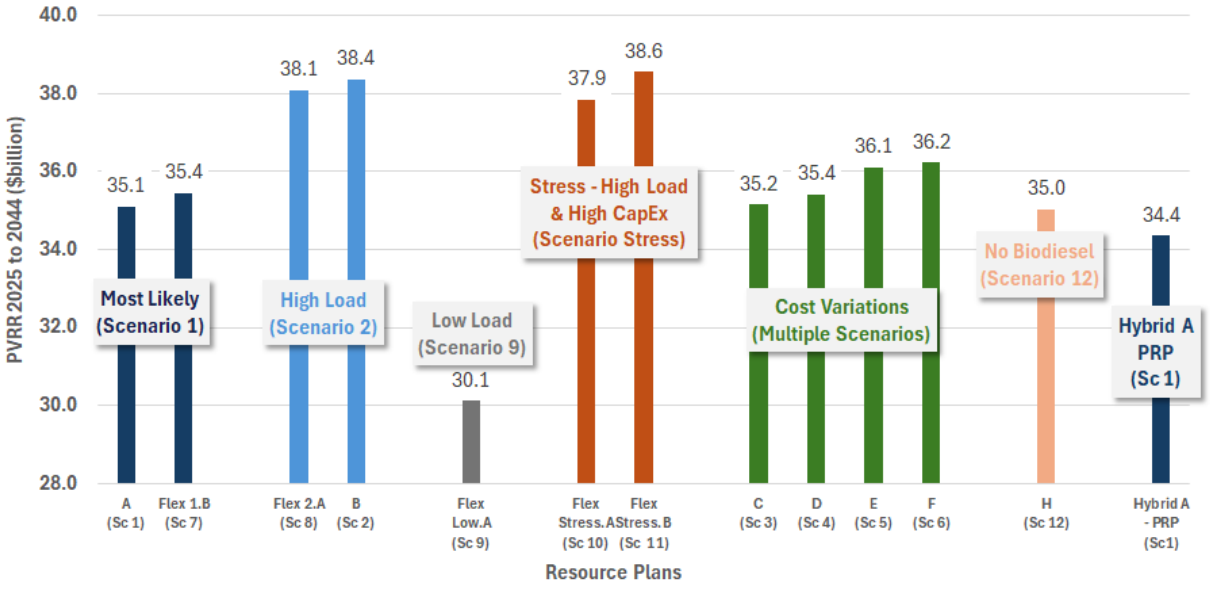
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A key finding is that the resource additions and costs of the 2025 IRP are dominated by fixed decisions. The Fixed Decisions represent planned resource additions and the AES retirement extension over the that were dictated outside the confines of the 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)[10], 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).

[10] See Case Number NEPR-MI-2024-0002, in Re: LUMA's Accelerated Storage Addition Program ("ASAP").

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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 Six Years (MW)[11]

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.

[11] As used in this table and further discussed in this IRP, the term DPV refers to distributed photovoltaics and the term CHP refers to combined heat and power generation facilities.

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Table 6: Preferred Resource Plan Additions 2025 to 2044[12]

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		
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%**

[12] As used in this table and as further discussed in this IRP, "Tranche" refers to one of a series of competitive procurements for utility scale renewable energy and battery energy storage services required to be conducted by PREPA pursuant to 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. Also, the term "PREPA HydroCo" refers to PREPA's existing hydroelectric generation facilities; "Emergency Generator" refers to the emergency generation to be added to the Puerto Rico system as a temporary addition to support the current shortfall in reliable, approved by PREB in Case No. NEPR-MI-2024-0005, In re: Electric System Priority Stabilization Plan; "Energiza" refers to the proposed 478 MW natural gas-fired generation facility with respect to which PREPA executed a power purchase and operating agreement approved by PREB in Case Number NEPR-AP-2025-0003, In re: Petition for approval of amendment to PPA between Energiza, LLC and PREPA; "Solar" refers to utility scale solar generation projects approved prior to the currently effective IRP; the "Regulation Only BESS (4x25MW)" refers to the LUMA proposed project for interconnection of 4 BESS of 25MW at LUMA 38 kV system for system reliability referred to as the "4x25 MW BESS T&D Project" approved in Case No. NEPR-MI-2022, In re: Review of the Puerto Rico Electric Power Authority's 10-Year Infrastructure Plan- December 2020; "New Genera Units" refers to _____; "DR" refers to the LUMA demand response programs approved in PREB Case Number NEPR-MI-2022-0001, In re: Energy Efficiency and Demand Response Transition Period Plan.

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 (%)
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%**

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 Landfill 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 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 provides an overview, discussion and recommendations regarding the generation technologies, energy storage technologies and fuels considered in the 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 [13] 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.

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 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

[13] 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

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 interchangeable 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 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, or 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 a 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 years 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. 57-2014 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 known as the Act to Transform the Puerto Rico Electric System, 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 the Puerto Rico electric system, authorizing PREPA to sell, transfer, or enter public-private partnerships to operate PREPA's assets and operations. Based on the legal framework established by Act 120-2018, LUMA was contracted to operate the transmission and distribution system and Genera to manage the generation. The Puerto Rico Energy Public Policy Act, Act No. 17-2019, was subsequently enacted to update the public policy regulatory framework to govern the energy landscape in Puerto Rico

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 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 Table 8 and Table 9 below.

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.

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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 abuse 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.

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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.

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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,

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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 affordability particularly in areas vulnerable to grid instability or natural disasters the 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 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.

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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.[14]
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.

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

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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	Agency	Description
Infrastructure Planning Regulation (Planning Regulation 22), Regulation 4861	Puerto Rico Planning Board	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	Puerto Rico Planning Board	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	Agency	Description
Regulation of New Competencies to Make Urban Development Viable (Planning Regulation No. 21), Regulation 4795	Puerto Rico Planning Board	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	Department of Natural and Environmental Resources	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	Telecommunications Bureau of the Puerto Rico Public Service Regulatory Board	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	Department of Natural and Environmental Resources	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	Puerto Rico Planning Board	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	Puerto Rico Planning Board	Establishes development rules in flood-prone areas, important for siting substations, generation, and other energy assets.
Puerto Rico Water Quality Standards Regulation, Regulation 9677	Department of Natural and Environmental Resources	Establishes rules to preserve, maintain and enhance the quality of waters in Puerto Rico compatible with the social and economic needs of Puerto Rico; designates uses for which the quality of water bodies shall be maintained and protected; promulgates water quality standards to sustain designated uses; identifies other rules and regulations applicable to sources of pollution that may affect water quality; and establishes other measures to achieve and maintain the quality of the waters of Puerto Rico.
Regulation for the Control of Atmospheric Pollution (as amended, Regulation 5300, as amended	Department of Natural and Environmental Resources	Contains requirements governing sources of air pollution in Puerto Rico.

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.
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.

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Industry Codes & Standards	Description
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.
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.

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Industry Codes & Standards	Description
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.
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.

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Industry Codes & Standards	Description
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.
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.

Industry Codes & Standards	Description
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 technical documents and specifications that supplement PREPAS Regulations
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 ongoing 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.[15]

2.2.9 Technical Bulletins

[15]See: https://lumapr.com/technical-documents-and-bulletins/?lang=en

LUMA has published a series of technical bulletins that provide guidance on engineering standards, materials, and construction practices.[16]

2.2.10 Others

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

Table 16: United 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.

[16] https://lumapr.com/technical-documents-and-bulletins/?lang=en

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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.
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-2024-027 – Investment Program in a Four-Year Term Approved for Fiscal Years 2024-2025 to 2027-2028	Approves a four-year investment plan that integrates all of Puerto Rico's investments throughout all its agencies. It is an instrument of short and long-term planning. Energy infrastructure is mentioned in the plan.
OE-2025-003 – Critical and Emergency Projects Fast-Track	Simplifies and expedites permitting processes for federally funded projects, as well as for critical, strategic, and emergency initiatives, including those related to energy infrastructure.
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.

Executive Orders	Description
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.

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.

Administrative Procedures	Description
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.
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.
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.

Programs	Description
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 for expenditures made after December 31, 2025, 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 with respect to property, the construction of which begins after June 30, 2026, 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 with respect to qualified new energy efficient homes acquired after June 30, 2026, 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 and investment in clean energy facilities, are repealed by OBBA §§70512–70513. Effective dates vary.

- §45X IRC, the Advanced Manufacturing Production Credit (AMPC), which supports the domestic manufacturing of solar modules, batteries, and other clean energy components and minerals, is modified under OBBA §70514. The OBBA terminates the AMPC for wind components sold after 2027 and phases out the AMPC for critical minerals beginning in 2031. The AMPC in general was otherwise set to phase-out starting in 2030, date that (as opposed to other credits) was not accelerated by the OBBA.

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 of 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.

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.[17] 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

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

- 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

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 the goals of: 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” 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

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 a 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[18]

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.

[18] 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.

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 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 resource decisions reflect both regulatory obligations and environmental risk mitigation.

SO_2 NAAQS

The Clean Air Act[19] (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[20], 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).[21] 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."[22] 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.[23]

Puerto Rico has a SIP approved by EPA[24], 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")[25] 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).[26] 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

[19] 42 U.S.C. §7401, et seq.
[20] *Id*. §7409.
[21] *See* 40 C.F.R. Part 50.
[22] See 42 U.S.C. §7407(d)(1)(A)(i).
[23] *See* 42 U.S.C. §7410.
[24] *See* 40 C.F.R. Part 52, Subpart BBB.
[25] Regulation 5300, approved on July 26, 1995, as amended.
[26] *See* 75 Fed. Reg. 35520 (June 22, 2010).

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.[27] 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.[28]

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, 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.[29] 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.[30] 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).[31] 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

[27] *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).
[28] See 83 Fed. Reg. 1100.
[29] 85 Fed. Reg. 69504 (November 3, 2020).
[30] *See id*. 69506.
[31] 89 Fed. Reg. 16202 (March 6, 2024).

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	Generation Units	Capacity (MW)	Fuel	SO_2 EPA Final Designation	MATS Affected	Carbon Emissions
	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
	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.

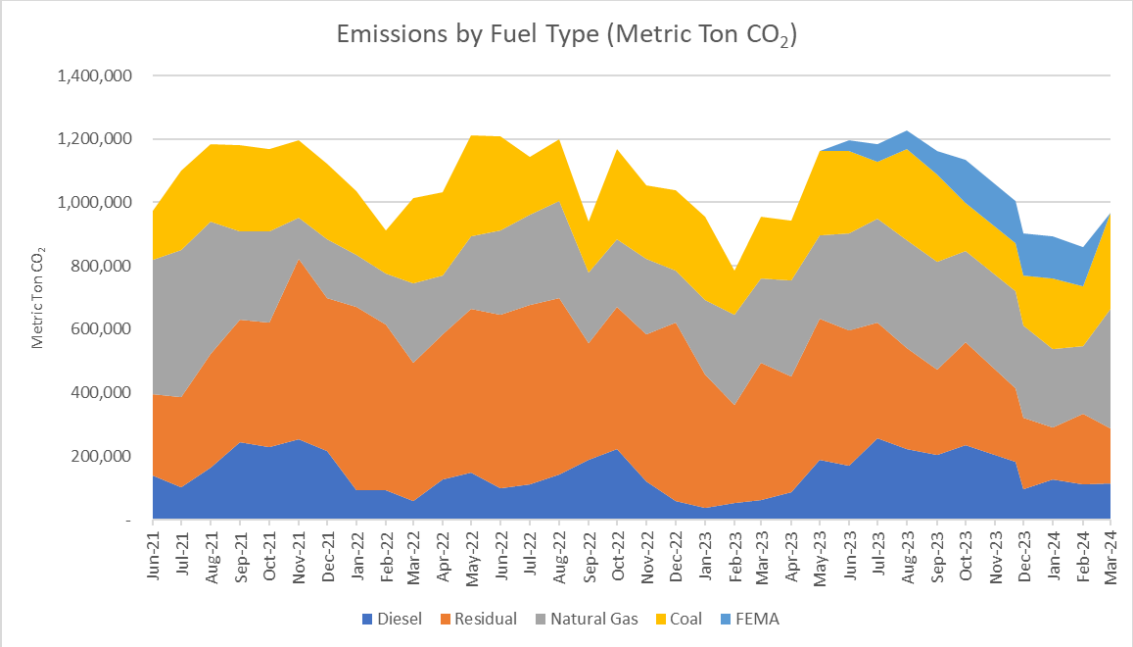
With respect to the PM2.5 NAAQS, based on information provided by Genera, the San Juan TM units (1-7) and the Palo Seco TM units (1-10) could be significant contributors of PM2.5 emissions.

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[32] 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[33]. 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[34] and the regulations adopted by EPA establishing National Emissions Standards for Hazardous Air Pollutants (NESHAP).[35]

[32] 42 U.S.C. §7412.
[33] 42 U.S.C. §7412(b).
[34] 42 U.S.C. §7412(c).
[35] 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).[36] 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.[37] In the 2019 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 2019 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.[38]

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.[39]

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

[36] *See* 77 Fed. Reg. 9304 (February 16, 2012).
[37] *See id.*
[38] *See* 89 Fed. Reg. 38508 (May 7, 2024).
[39] *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[40] 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	

[40] 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)

With respect to 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.[41]

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

[41] 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[42] 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 2019 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 2019 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)) [43] States are required to submit implementation plans within 24 months of the rule's publication.[44]

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.[45] 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.[46] The period to comment on this rule ended on August 7, 2025.[47]

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

[42] 42 U.S.C. §7411.
[43] See 89 Fed. Reg. 39798 (May 9, 2024).
[44] *See id.*
[45] *See* 90 Fed. Reg. 25752 (June 17, 2025).
[46] *See id.* 25752.
[47] *See id.*

Clean Water Act Section

The Clean Water Act[48] (as amended, "CWA") is a comprehensive federal law governing water pollution. Section 301 of the CWA[49] 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.[50]

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.[51]

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.[52] 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)[53] of the CWA authorizes EPA to issue a variance for effluent limitations for the control of the thermal component of a discharge.[54] Section 316(b)[55] 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.[56] These requirements apply to facilities designed to withdraw at more than two million gallons per day.[57]

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

[48] 33 U.S.C. §§1251 *et seq.*
[49] 33 U.S.C. §1311.
[50] *See* 33 U.S.C. §1341; 12 LPRA 8002c(B)(7); Puerto Rico Water Quality Standards Regulation, Regulation 9677, approved April 30, 2025.
[51] *See* 40 C.F.R. Chapter I, Subchapter N.
[52] *See* 40 C.F.R. §423.10(a).
[53] *See* 33 U.S.C. §1326(a).
[54] See 40 C.F.R. §122.21(m)(6).
[55] *See* 33 U.S.C. §1326(b).
[56] *See* 40 C.F.R. Parts 122 and 125, Subparts I, J and N.
[57] *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.[58]

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.

[58] *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 2019 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 a 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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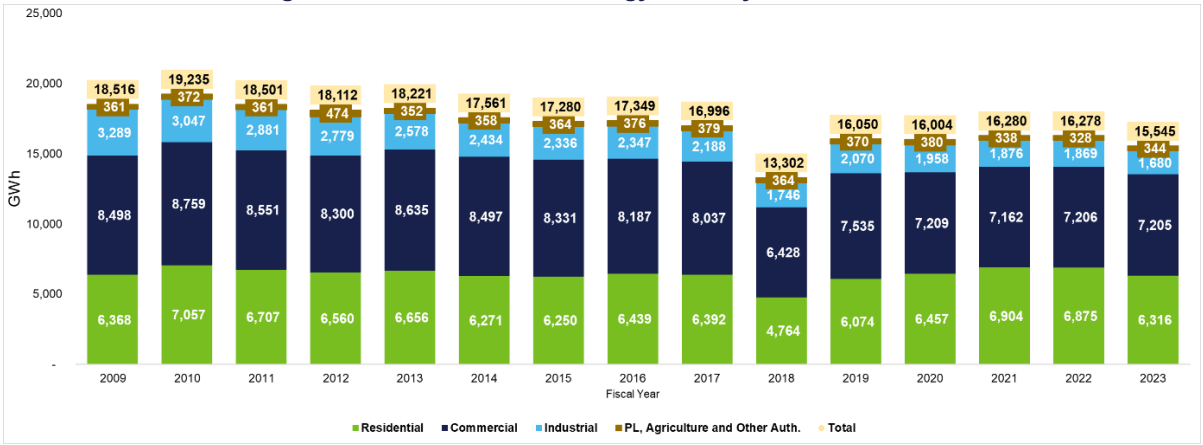
The 2019 IRP considered historic total sales data from FY2000 to FY2017. After Hurricane María hit in September 2017, there was a significant shift in sales trends. A compound annual growth rate of -1.48% was evident between 2017 and 2023.

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

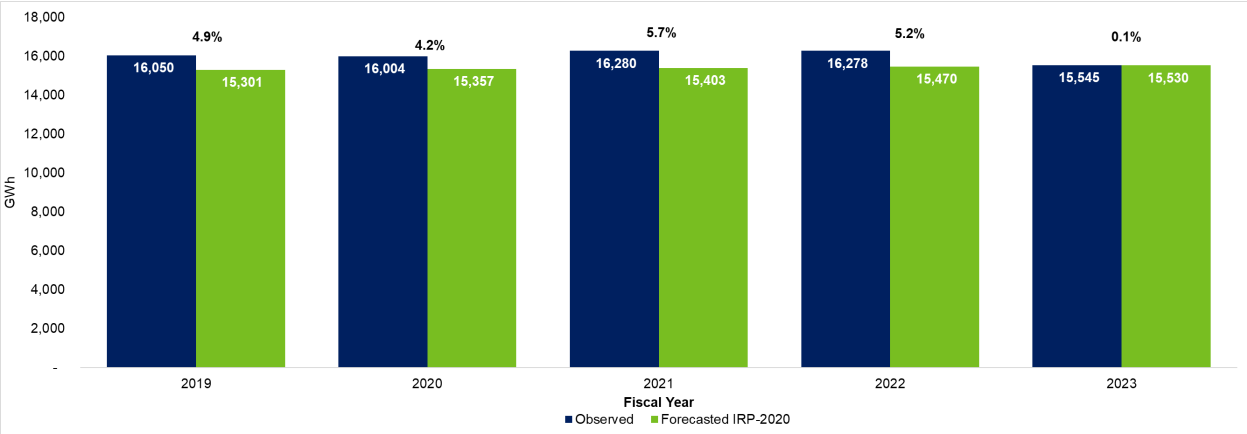
Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2009	6,368	8,498	3,289	274	31	57	18,516
2010	7,057	8,759	3,047	285	30	58	19,235
2011	6,707	8,551	2,881	281	29	51	18,501
2012	6,560	8,300	2,779	398	27	49	18,112
2013	6,656	8,635	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 2019 IRP Forecast

The total historic sales at meter level compared to the 2019 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

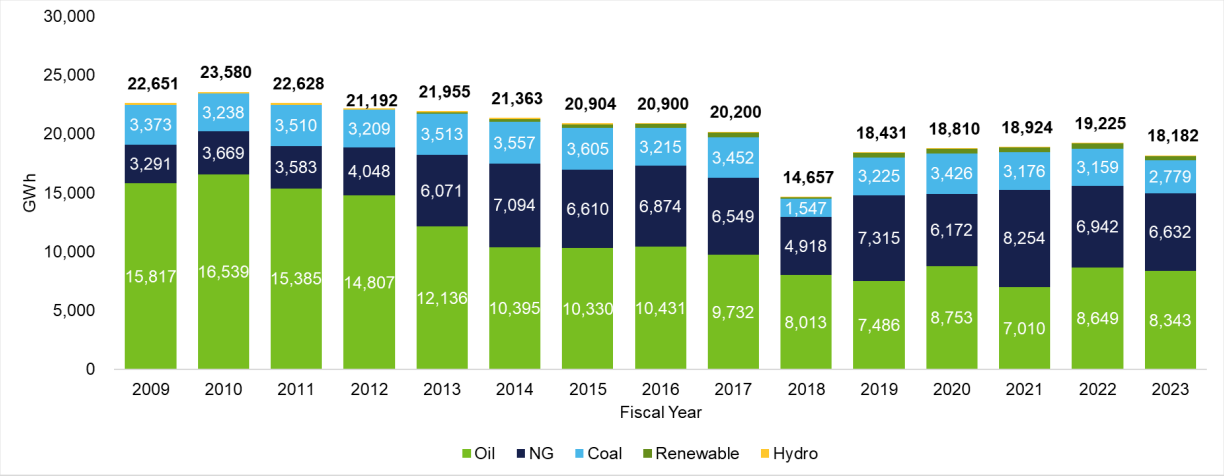


Table 28: Historic System Level Energy Generation

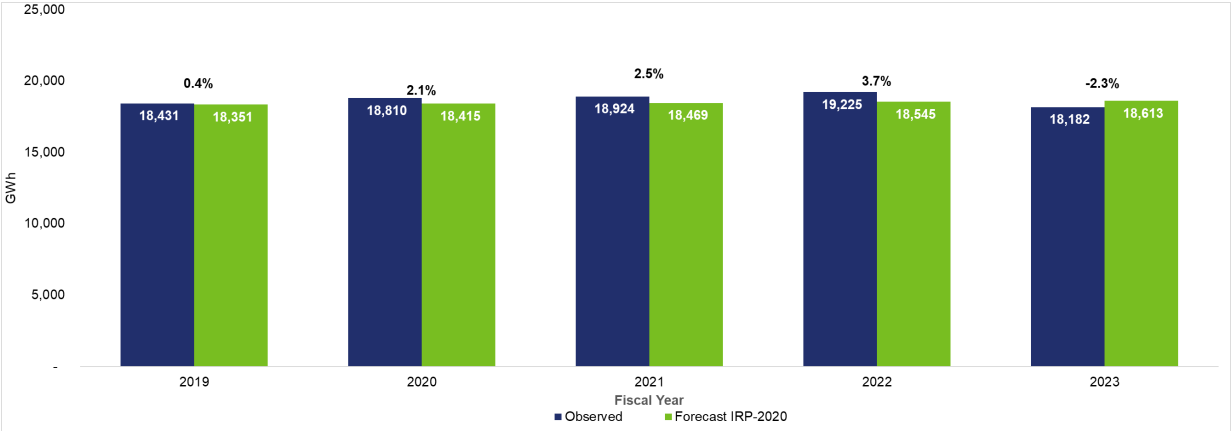
Fiscal Year	Gross Energy Generation (GWh)	Net Energy Generation (GWh)
2009	22,651	21,763
2010	23,580	22,562
2011	22,628	21,636
2012	22,192	21,204
2013	21,955	21,009
2014	21,363	20,508
2015	20,904	20,107
2016	20,900	20,113
2017[59]	20,200	19,449
2018	14,657	14,039
2019	18,431	17,753
2020	18,810	18,174
2021	18,924	18,289
2022	19,225	18,536
2023	18,182	17,568

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

3.1.4 Gross Generation - Historic and 2019 IRP Forecast

The average annual variance between the historic and 2019 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 2019 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.

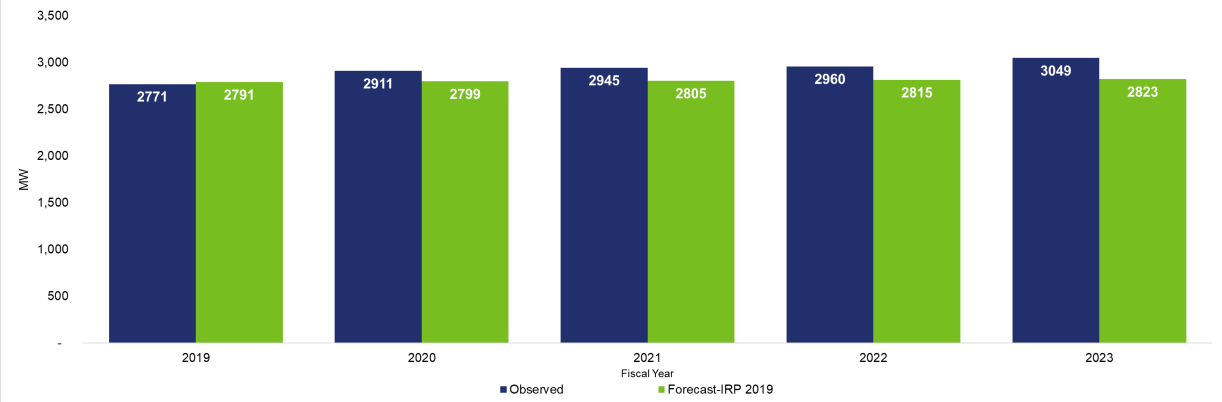
Table 29: Historical Coincident System Peak Demand

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 2019 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 2019 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.

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

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 the 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.[60]

$COVIDCOMtrans_t$ = 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.

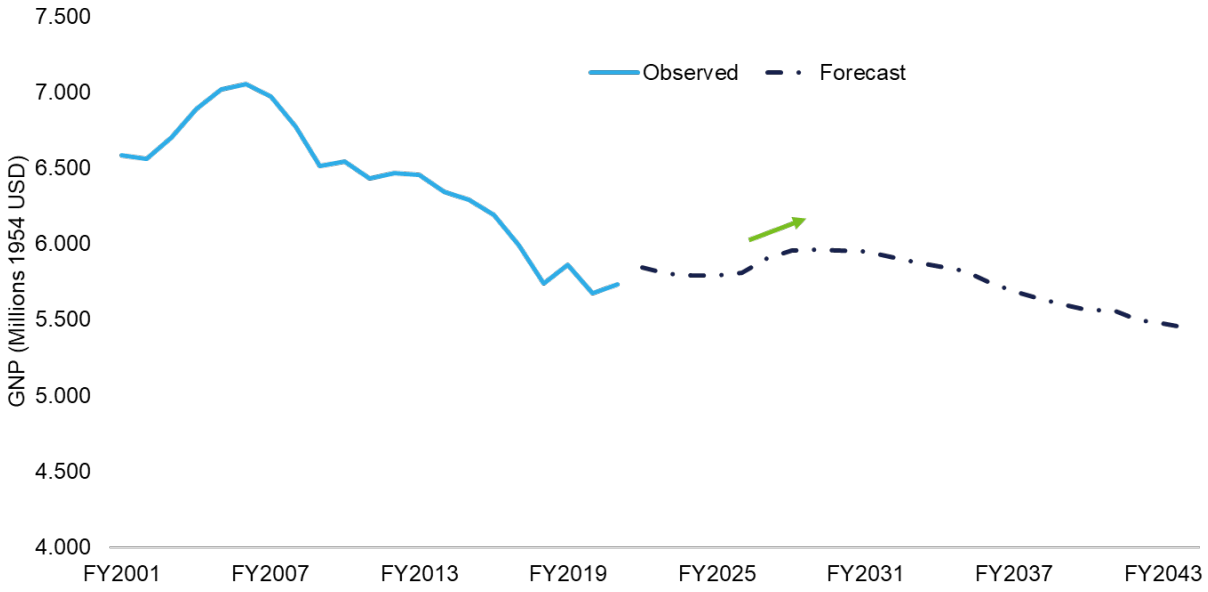
3.1.8 Exogenous Variables

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.

[60] 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.

Figure 8: Historic and Forecast Gross National Product



Population Forecast

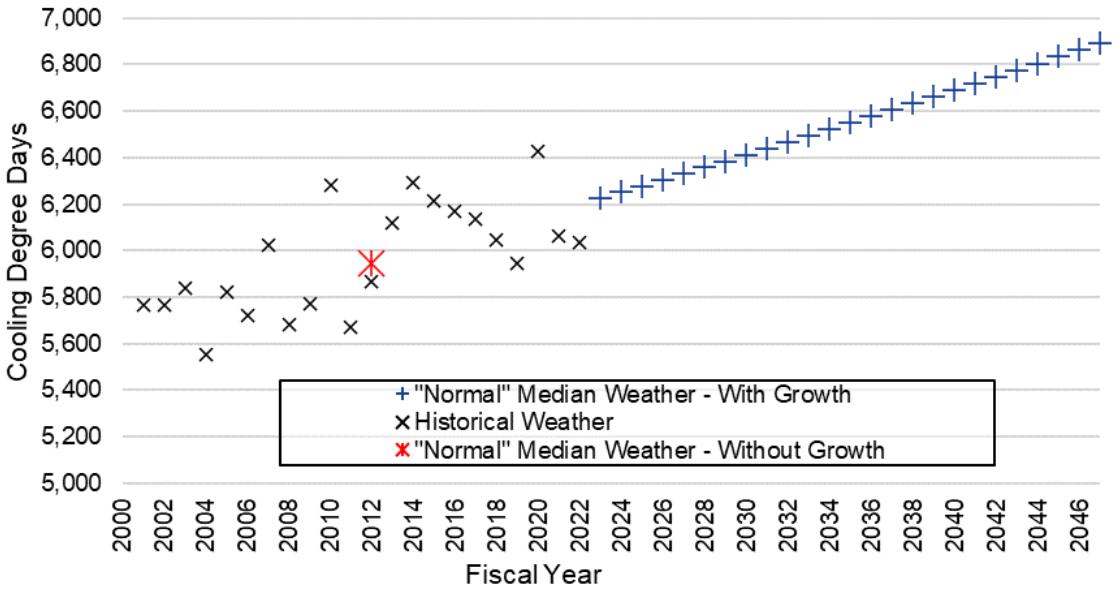
The population is anticipated to continue decreasing. The census revealed an increase in 2019 and 2020; however, the estimation after those years indicates a decline. The observed fiscal year 2001 to 2022 data exhibit a compound annual growth rate of -0.78%. The compound rate is anticipated to be similar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

Figure 9: Observed and Forecast Cooling Degree Days[61]



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.

[61] Source: NOAA, analysis by Guidehouse

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

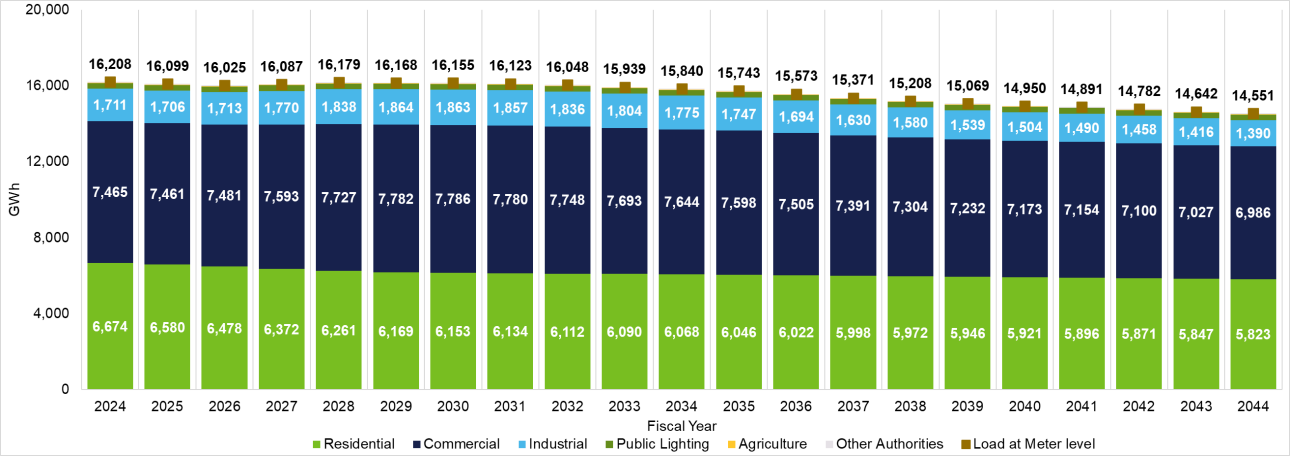


Table 30: Forecast Energy Sales

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.[62]

[62] 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.

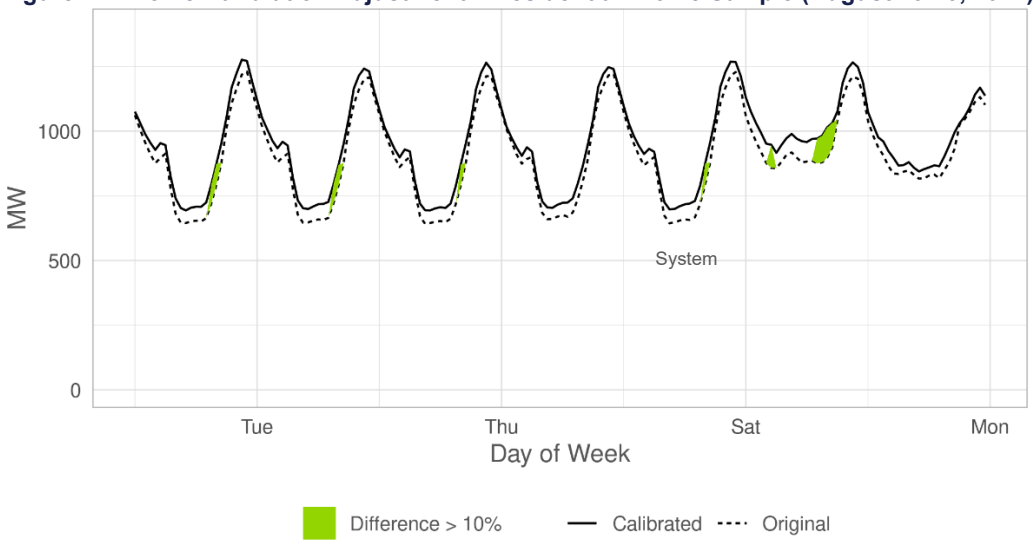
$Hour$ is a set of binaries, one for each hour of the day.

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)

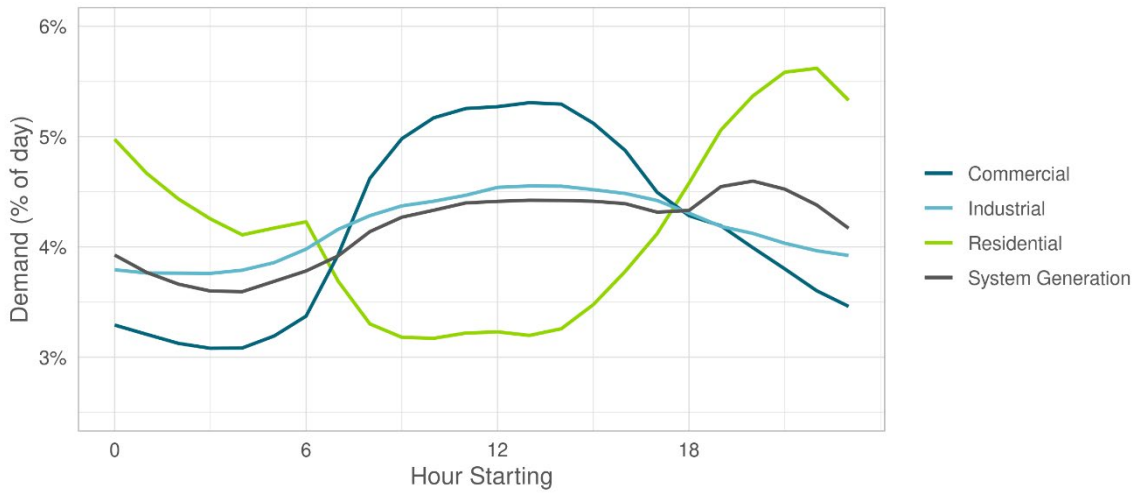


Figure 13 depicts average system-level demand profiles in FY2009 and FY2019. Over time, consumption during midday hours (8 a.m. - 3 p.m.) has declined, and consumption in the late afternoon and evening (4 p.m. - 10 p.m.) has increased slightly. These changes may result from increased adoption of air conditioning and the decline in Commercial sales, which contribute a greater share of mid-day demand.[63]

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

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

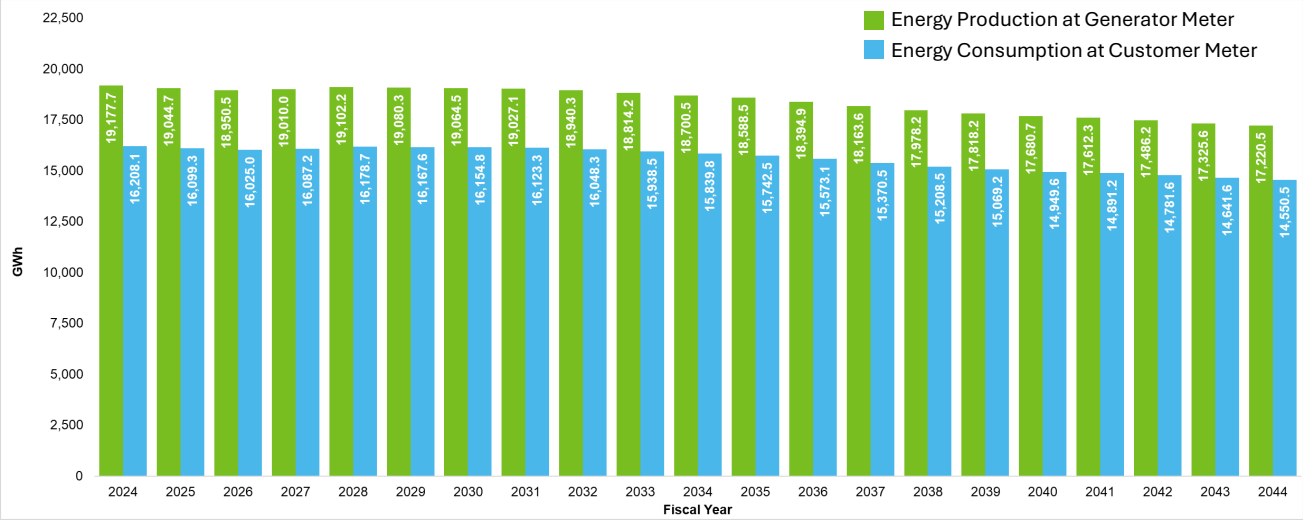
The energy forecast at the generator meter level was calculated by factoring in the losses based on customer class. Table 32 below shows the energy forecast at the generator meter level and Figure 14 compares the energy production to energy consumption at the meter level.

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

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:

- 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

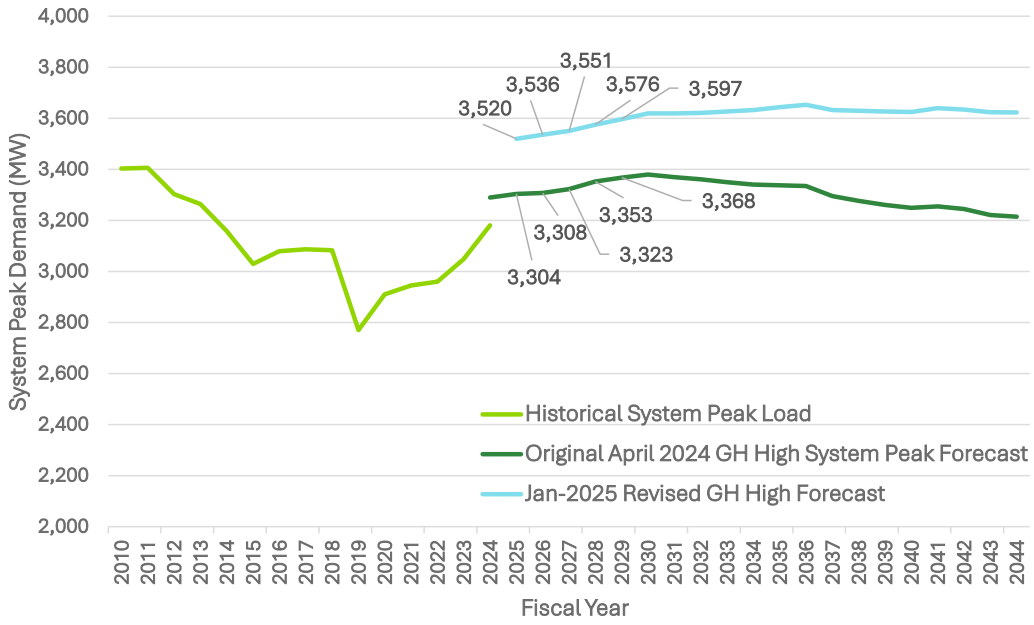
summer of 2024. The volatility factor is applied to the hourly disaggregation of peak monthly sales to reflect the historically observed variation in annual peak demand values due to factors beyond macroeconomic trends and monthly CDD.

- 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

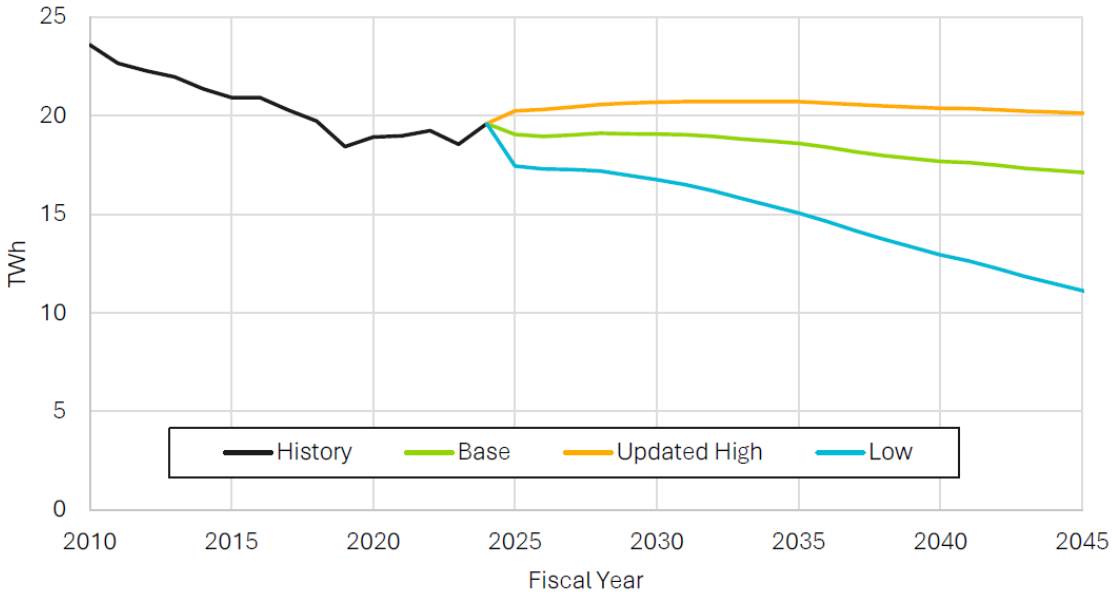


Table 34: Sales Forecast at Generator Level (High Scenario)

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.

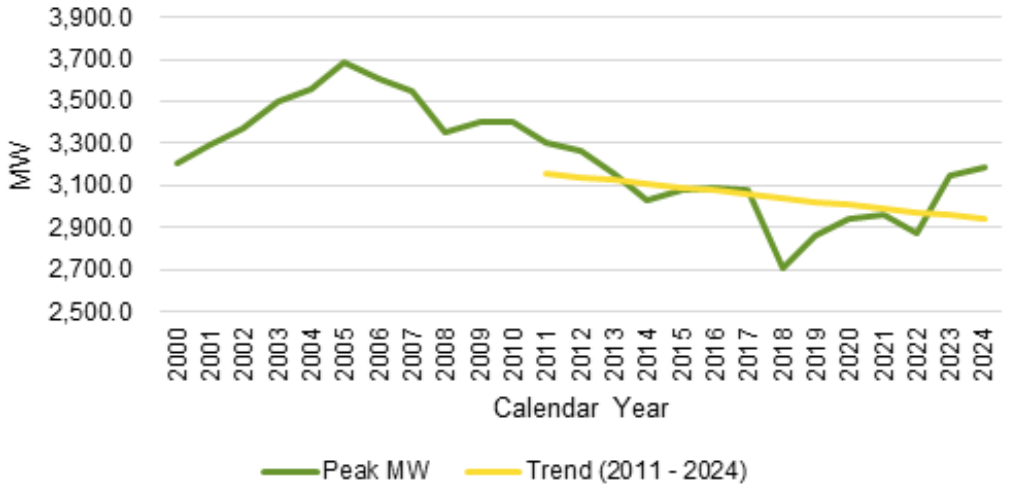
3.1.15 Peak Volatility Factor

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.

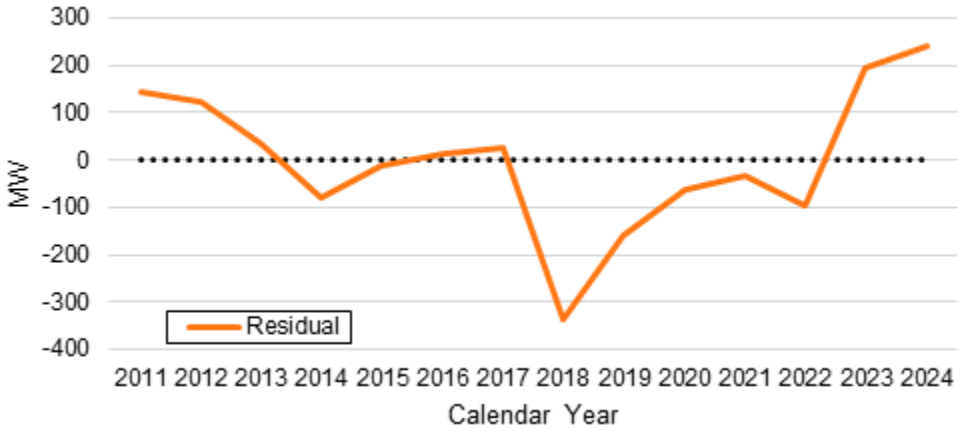
Figure 17 depicts historical observed peak generation (green line) with a linear trend (yellow line) during the historical IRP study period (2011-2024[64]).

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)

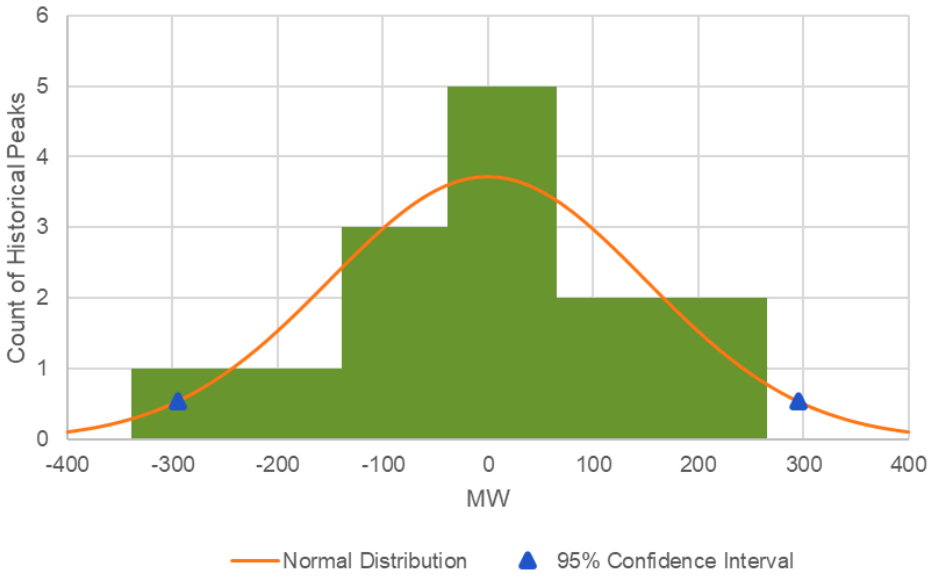


Step 3. Estimate Distribution of Peaks and 95th Percentile Peak: The GH team used the trend-normalized peaks to estimate a 95% confidence interval, assuming the trend-normalized peaks follow a normal distribution. The upper confidence interval value provides a peak volatility factor that can be added 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

[64] 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.[65] 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).

[65] 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.

2025 Integrated Resource Plan Report

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

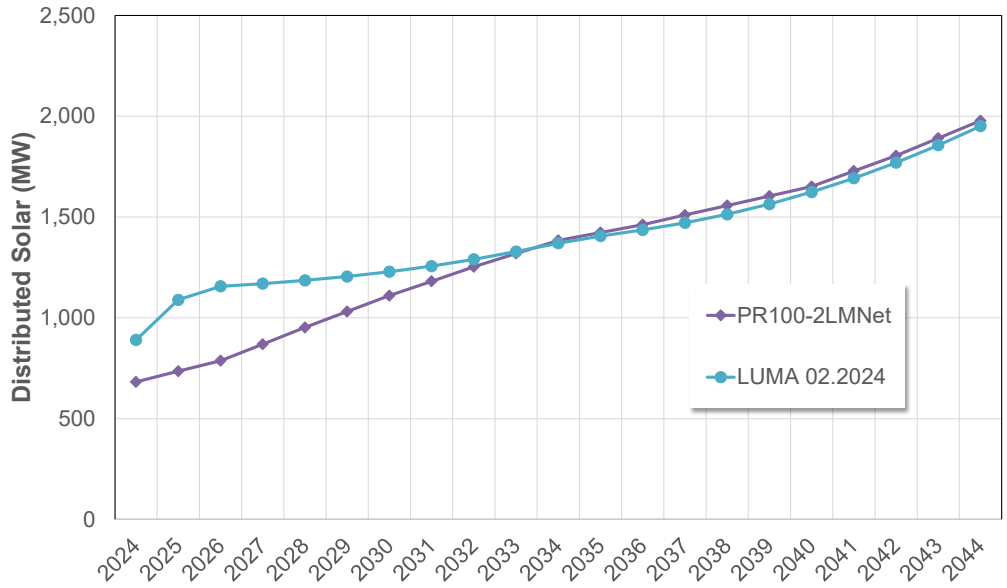


Table 35: Comparison of LUMA Base Case DPV and PR100 DPV Forecasts

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%

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

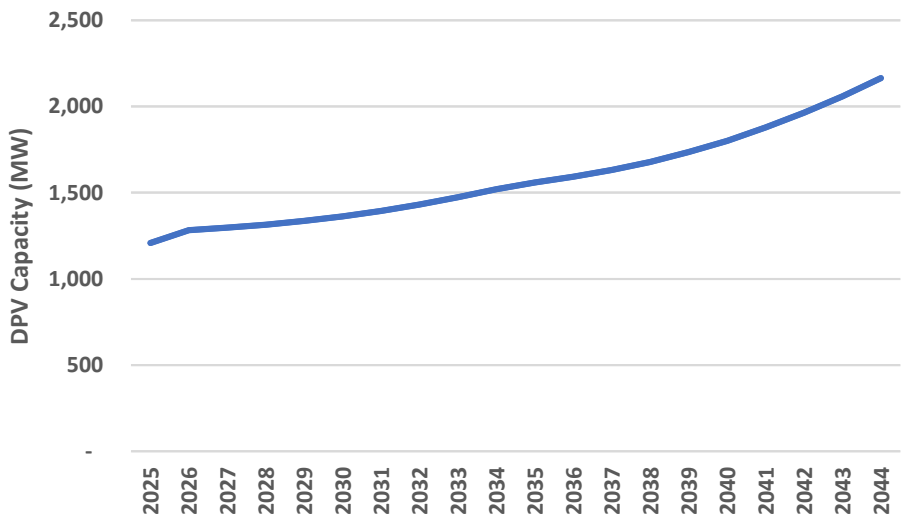
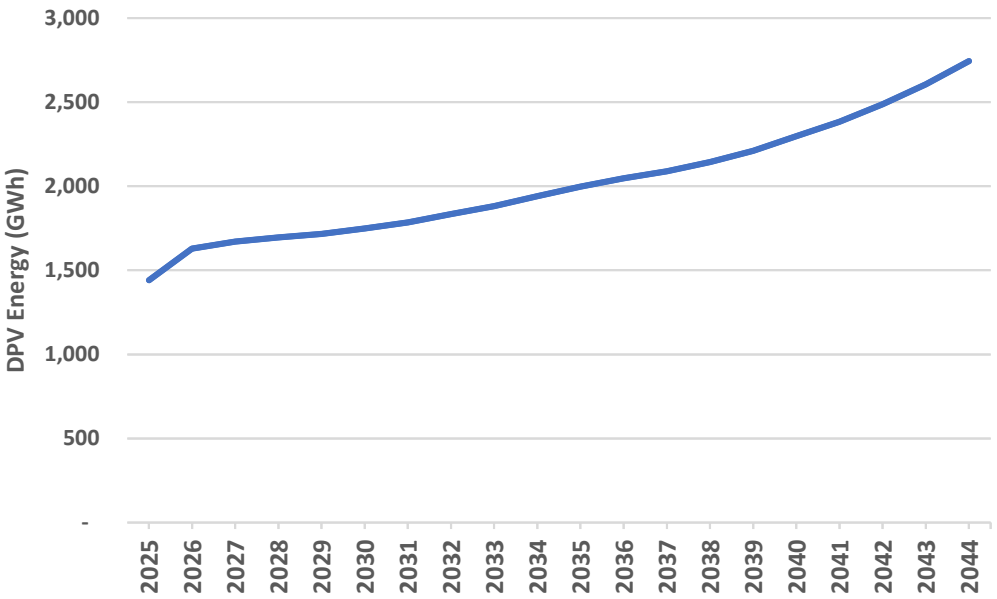


Figure 22 presents the forecast of the Base Case DPV energy impact as measured at the utility generator.

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 customer-owned DBESS batteries was 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.[66]

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

[66] This program was approved by the Energy Bureau in Case Number NEPR-MI-2022-0001, In re: Energy Efficiency and Transition Period Plan.

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 customers 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 analysis[67] 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.[68] 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.

[67] Guidehouse DR Potential Study, completed for LUMA August 2024.
[68] 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).[69] 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[70] 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:

[69] 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.
[70] PR100 Study, Sec. 5.2, Energy Efficiency. https://pr100.gov/

2025 Integrated Resource Plan Report

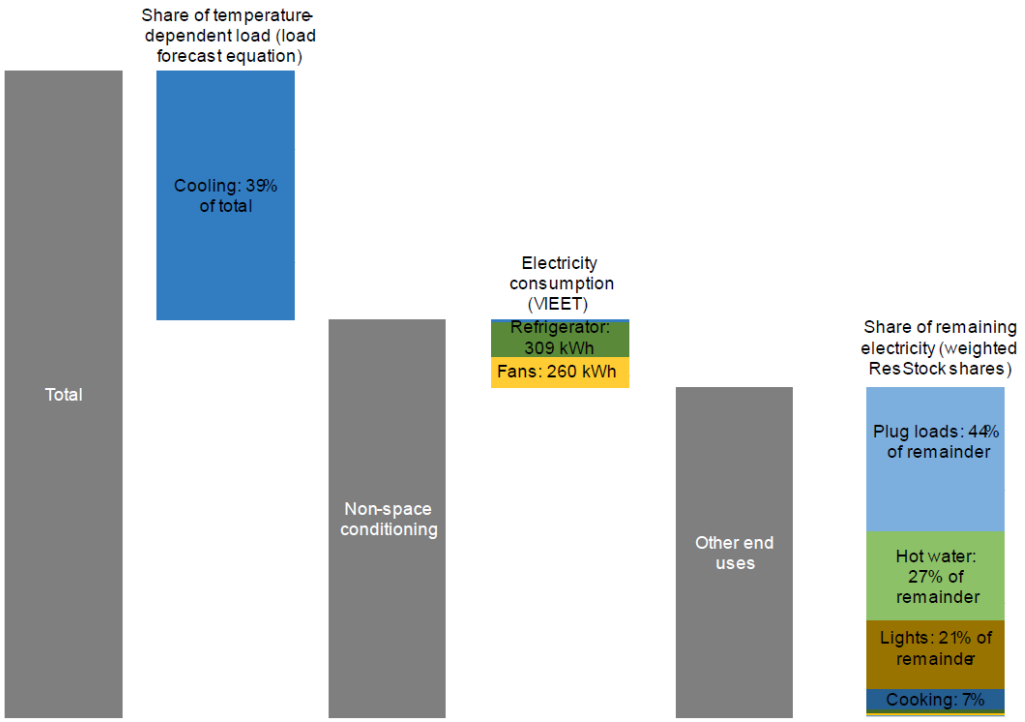
Figure 23: Annual End-Use Savings Formula[71]



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 2019 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[72]



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

[71] Ibid, Figure 68.
[72] 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[73]

End Use	TPP Measures	PR100 Assumptions	Sources/Notes
Cooling	Ductless air conditioner Window air conditioner	Window air conditioner efficiency projections from EIA (2023)74	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)[75]
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)[76]	

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[77]

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)

[73] Ibid, Table 18
[74] 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
[75] Energy Information Administration. (2020). Residential Energy Consumption Survey (RECS): 2020 RECS Survey Data. https://www.eia.gov/consumption/residential/data/2020/.
[76] EIA 2023
[77] 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.[78]

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[79]

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)[80]
16 years	Expected Useful Life (EUL)	DOE, Better Buildings (2021)[81]

[78] 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
[79] PR100 Report, Table 20.
[80] 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
[81] 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

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.[82] The projected savings based on the bottom-up approach do not achieve that goal.

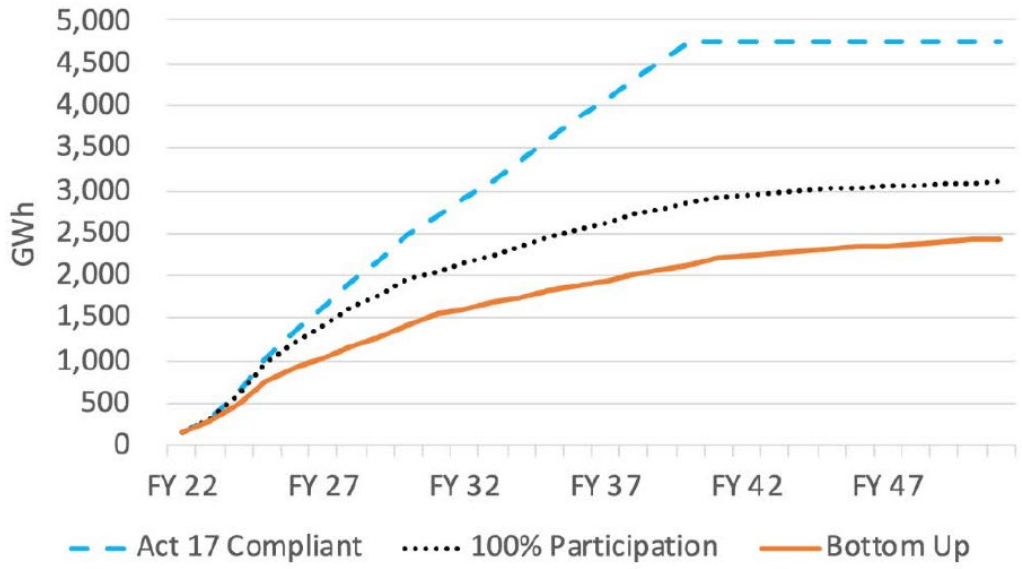
To create a projection that was compliant with the regulations, PR100 first assumed that 100% of residential and commercial systems participated in the EE programs and implemented high-efficiency options.

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.

[82] 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)[83]



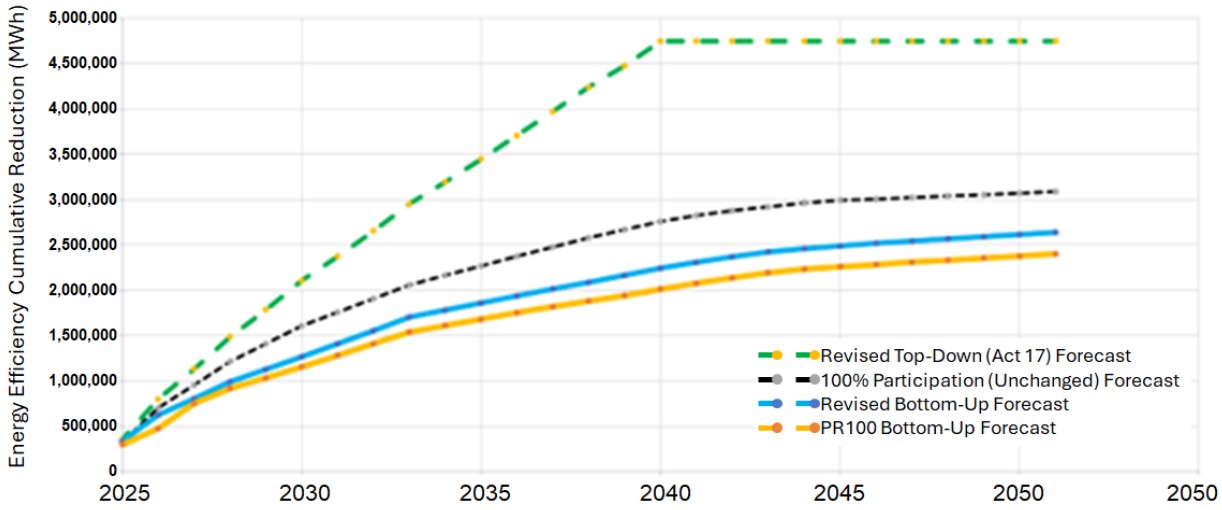
Adjusted Energy Efficiency Forecast

As indicated in Figure 25, the PR100 EE savings were forecasted to start in FY2022 based on the original TPP plan.[84] 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 TPP[85] 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.

[83] PR100 Study
[84] 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)
[85] 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)

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.

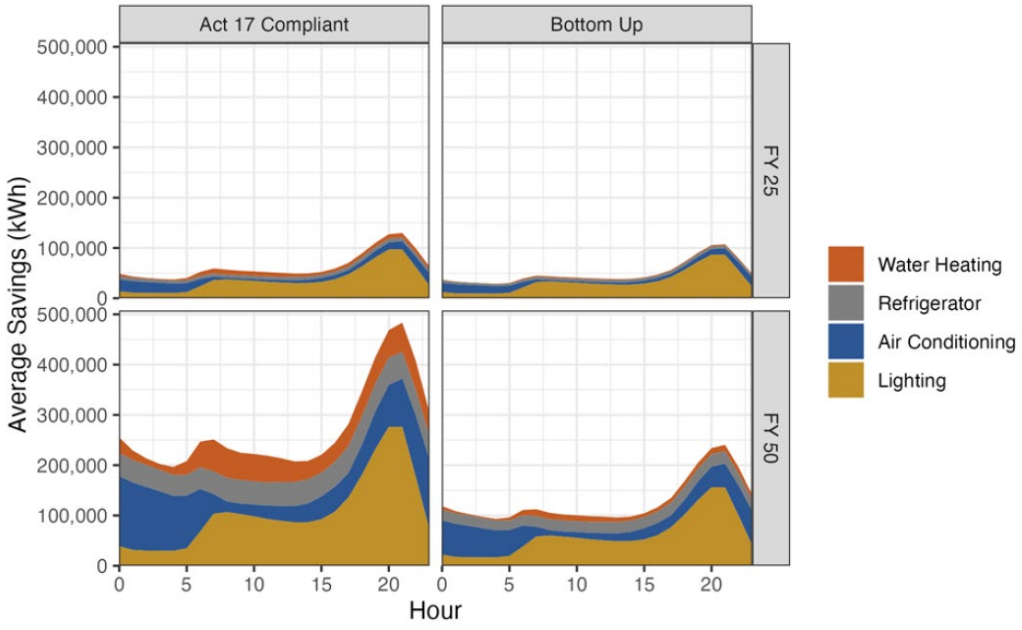
Load Shape Changes Due to EE

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.[86] 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.

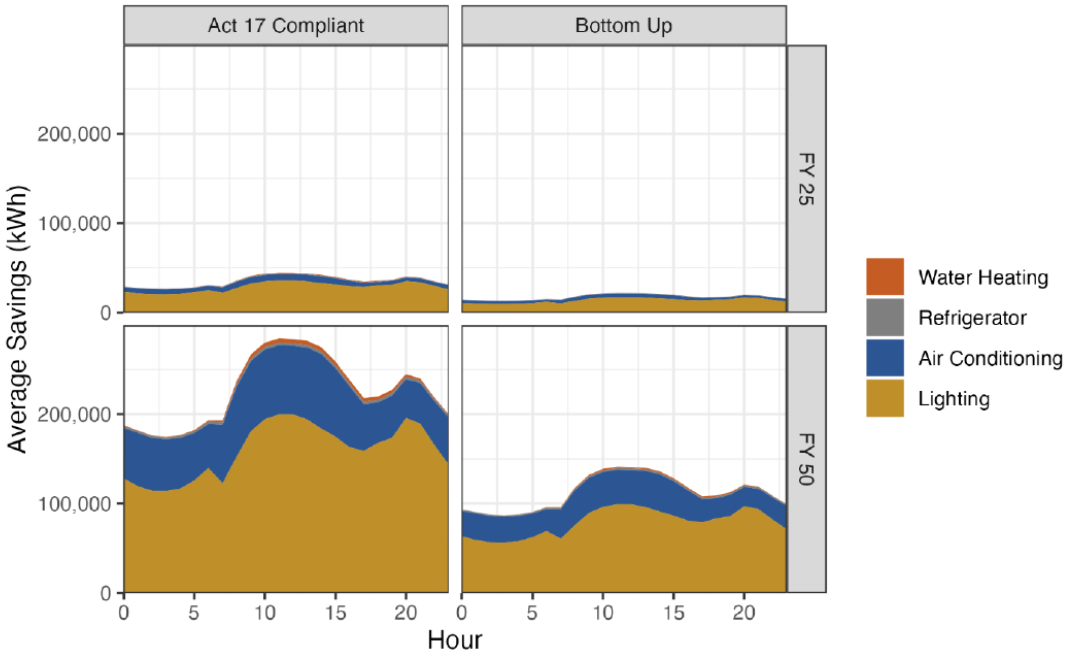
Figure 27 and Figure 28 show the average hourly savings for the top-down and bottom-up forecasts in FY2025 and FY2050 for the residential and commercial sectors, respectively. The savings peak at 9 p.m. in residential buildings, a bit before the overall residential peak, because lighting contributes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

Figure 27: Average Hourly Electricity Savings – Residential[87]



[86] This tool is not publicly available.
[87] PR100 Report, Figure 77

Figure 28: Average Hourly Commercial Electricity Savings[88]



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.[89] 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.[90] This EE savings target of 30% by 2040 was subsequently absorbed in Act 17, but the first EE programs were only implemented,

[88] Ibid, Figure 78
[89] "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
[90] 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)

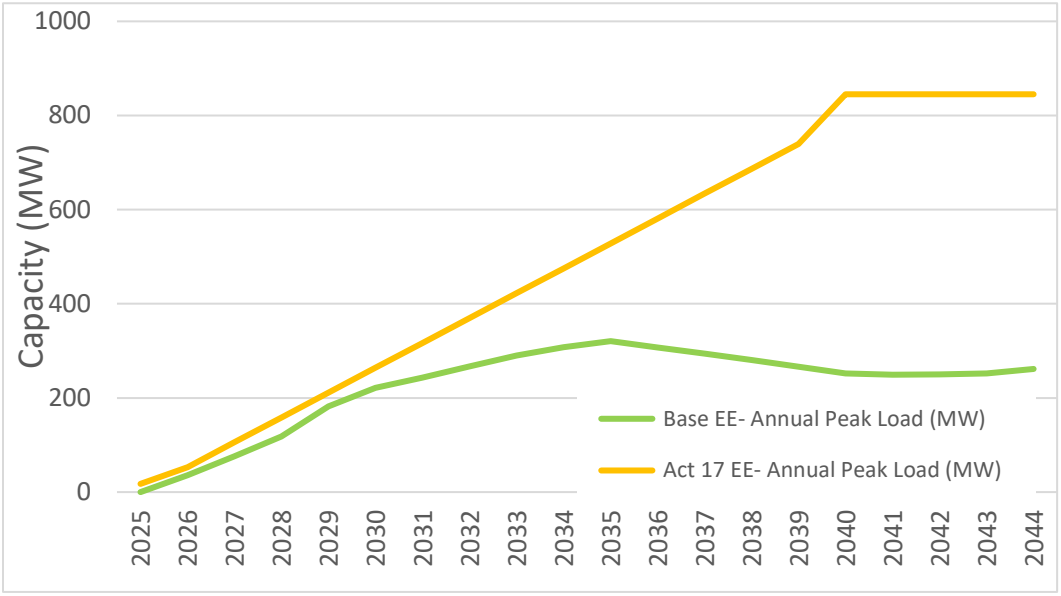
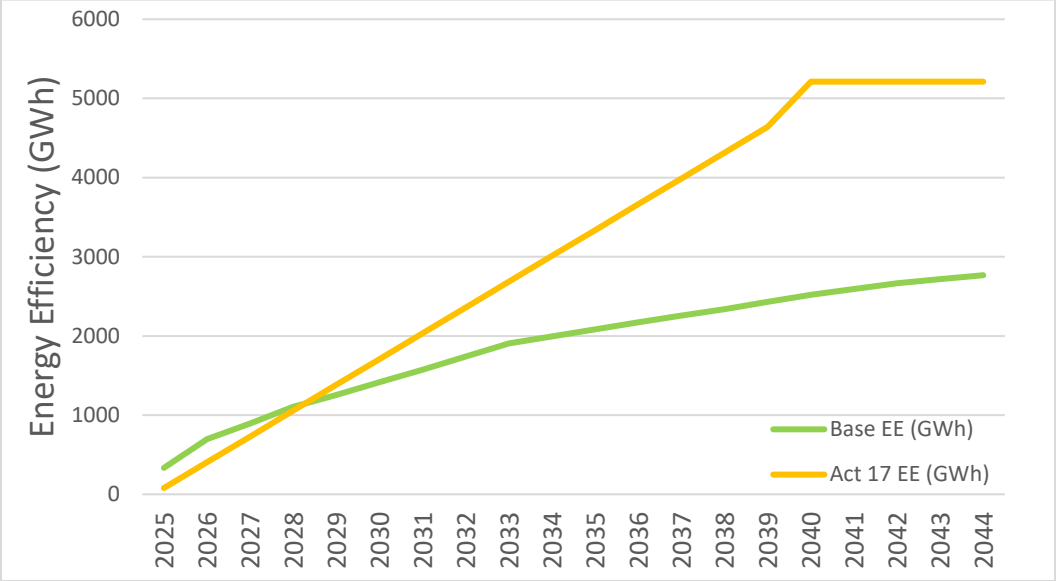


Figure 30 compares the base EE and the Act 17 EE energy savings (in GWh).

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.

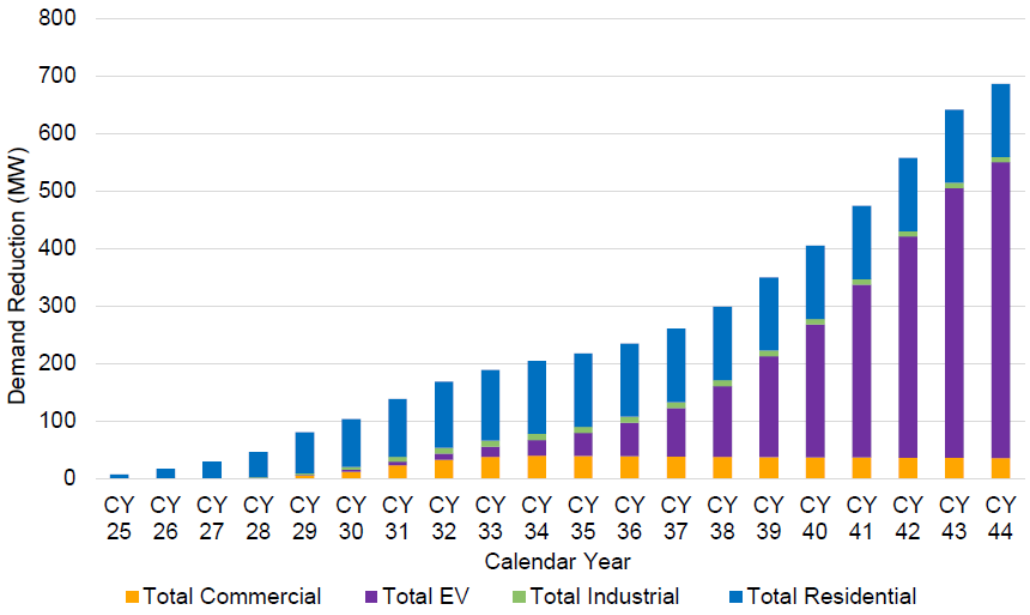
Table 41: Demand Response Reduction with "Optimal" and Focused Deployment

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

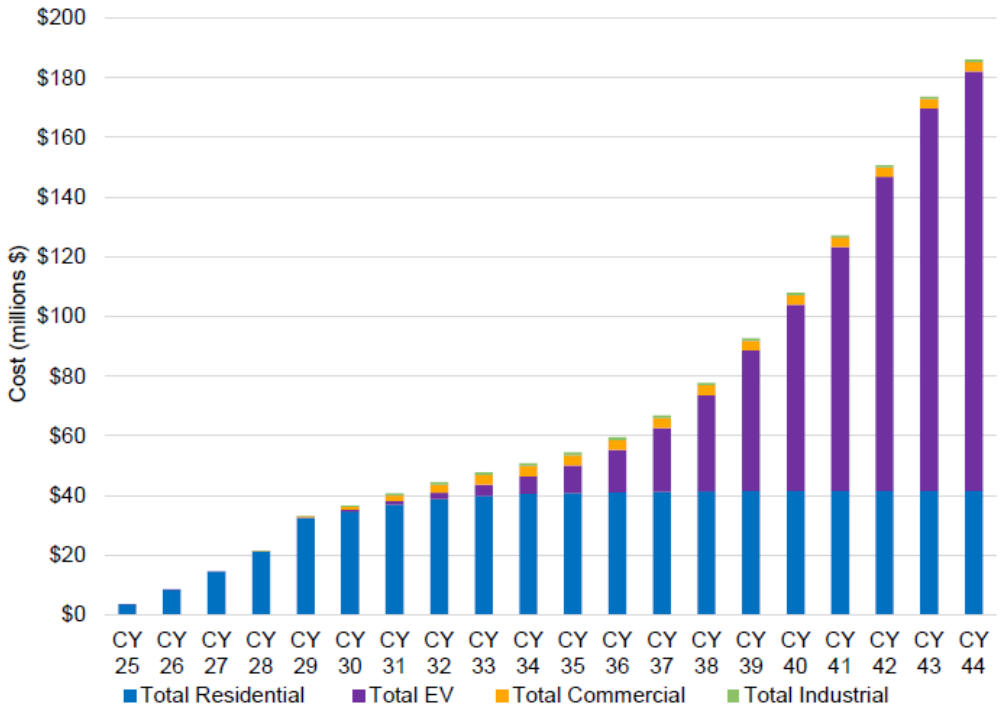
The analysis conducted on the GH DR Potential Study shows that the residential sector has the highest potential savings, followed by commercial, industrial, and EV sectors. However, due to the expected increase in EVs and participation in EV-related measures, EV becomes the sector with the highest potential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

Figure 31: Demand Reduction over Forecast Period by Sector



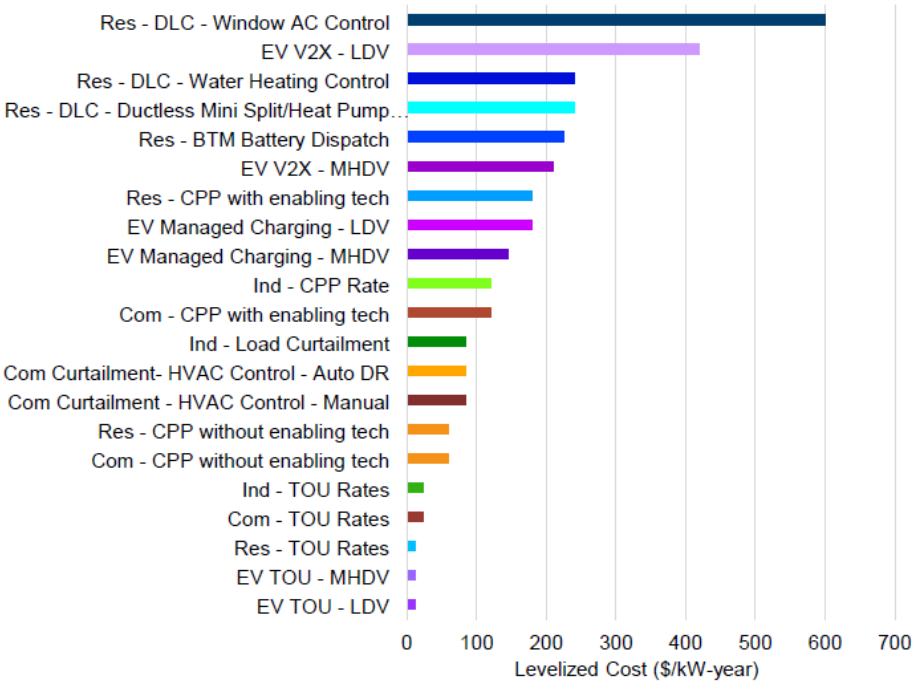
The cost for each sector of implementing the different DR measures is presented in Figure 32. Like the potential savings, the residential sector has the highest costs over the first few years, while over time EV becomes the sector with the highest associated cost.

Figure 32: Cost over Forecast Period by Sector



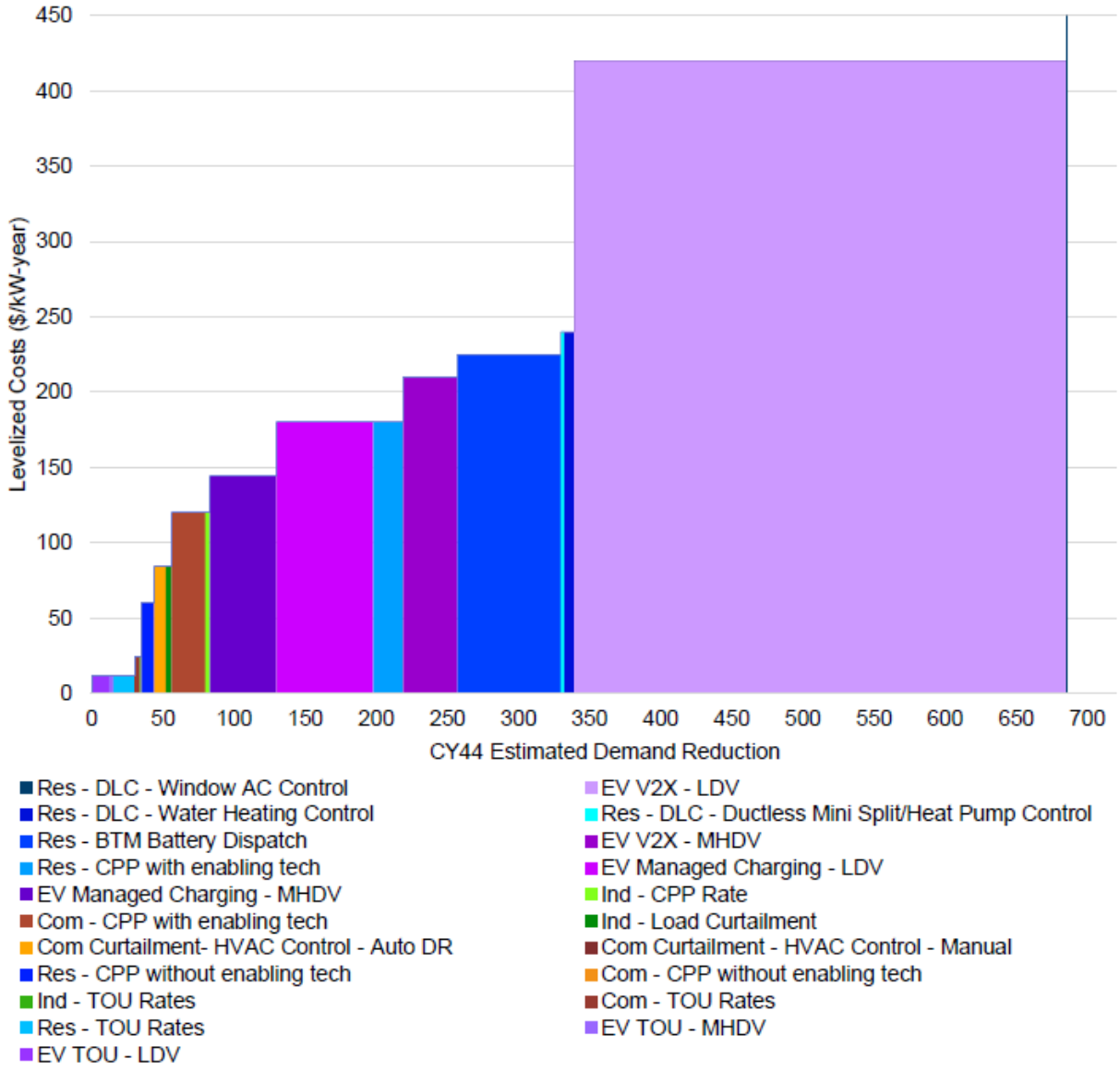
The comprehensive list of levelized cost values used is presented in Figure 33, including the 20% Puerto Rico Cost Adder.

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%).[91] 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.[92] 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.[93] 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.[94] 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 Charging 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.

[91] "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
[92] Global Fleet; https://www.globalfleet.com/en/wikifleet/puerto-rico
[93] 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
[94] 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.

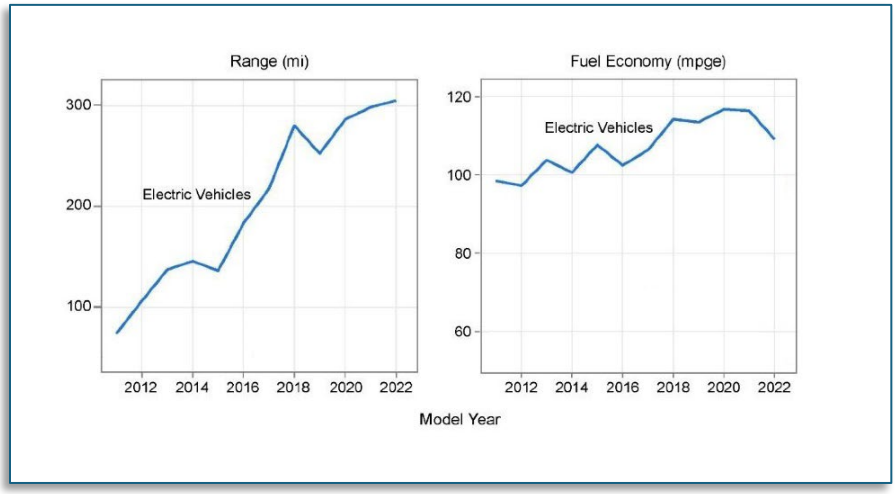
EPA estimated real-world data, which is measured using additional laboratory tests to capture a broader range of operating conditions (including hot and cold weather, higher speeds, and faster accelerations) encountered by an average driver. This expanded set of tests is referred to as "5-cycle" testing. 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.[95].

[95] 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[96]



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.[97] 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.

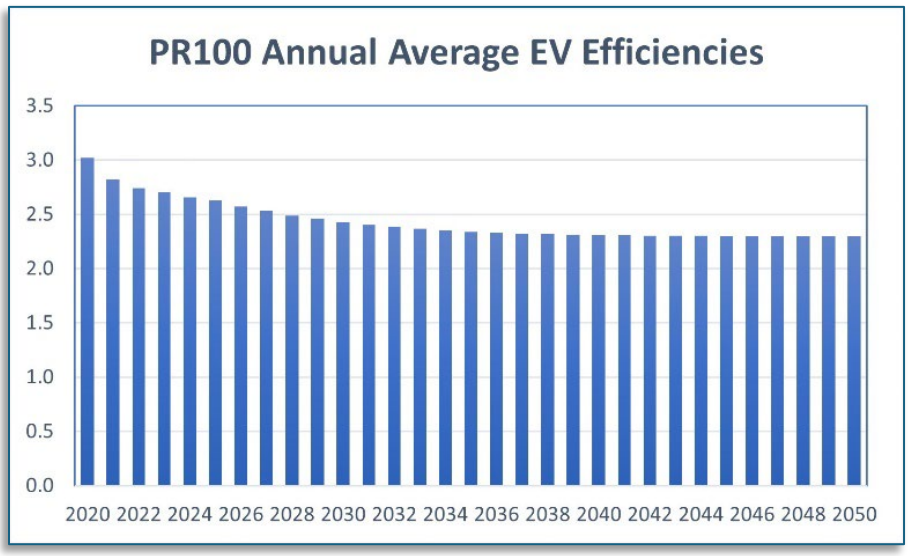
From model year 1981 to model year 2004, the trend reversed, and average new vehicle weight began to slowly but steadily climb. By 2004, the average weight of a new vehicle had increased 28% from the model year 1981 and reached 4,111 pounds per vehicle, partly because of the increasing truck share. The 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.

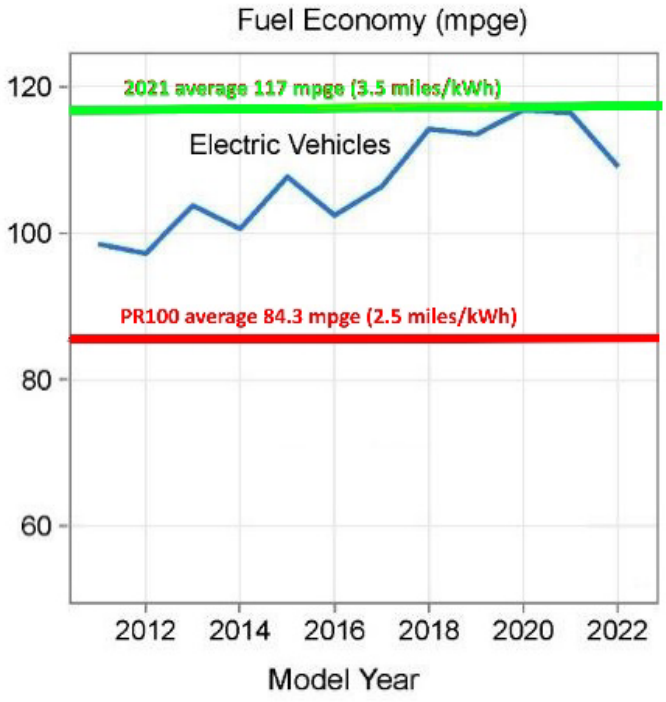
[96] "The 2023 EPA Automotive Trends Report: Greenhouse Gas Emissions, Fuel Economy, and Technology since 1975," U.S. EPA EPA-420-R-23-033, December 2023; https://www.epa.gov/system/files/documents/2023-12/420r23033.pdf
[97] ibid

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.

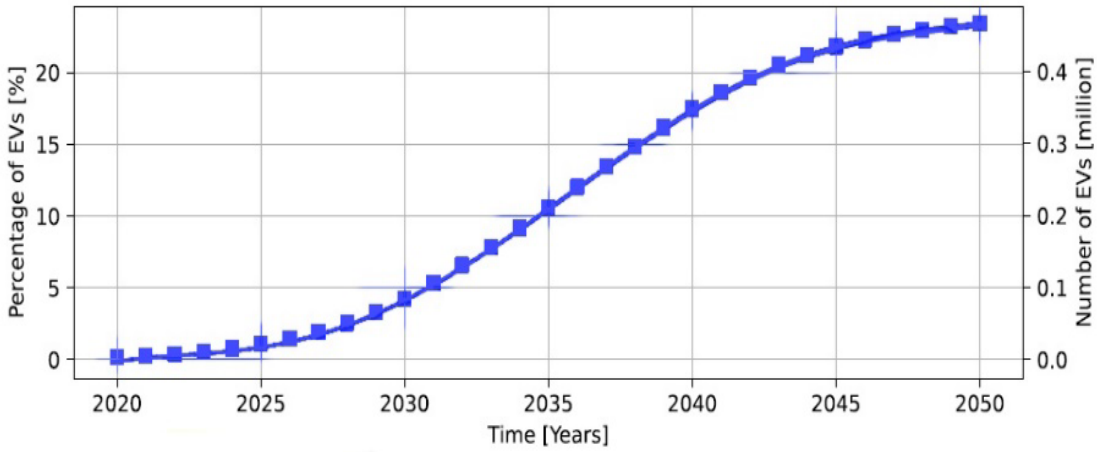
As more data from the LUMA EV TOU pilot becomes available, many questions about Puerto Rico's driving behaviors are expected to be answered.[98]

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%.

[98] 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



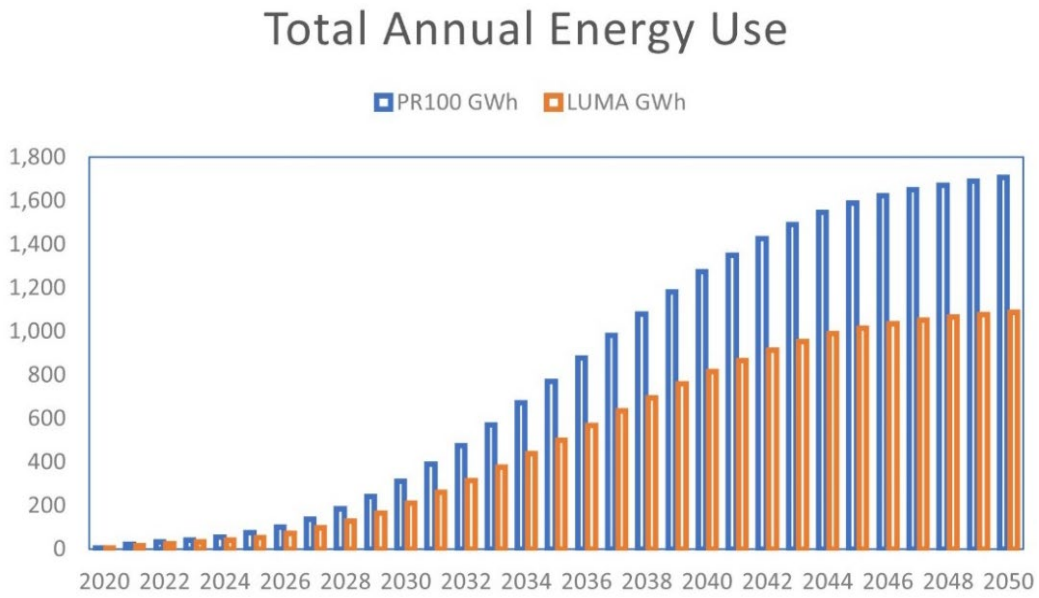
The vehicle count shown in the context of LDV market penetration is inconsistent with the mileage and energy use provided in a separate analysis in the PR100 study. Using vehicle counts from Figure 38 above, the electricity use per car becomes too high, ~10 kWh/day per car. Perhaps the mileage and the 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.

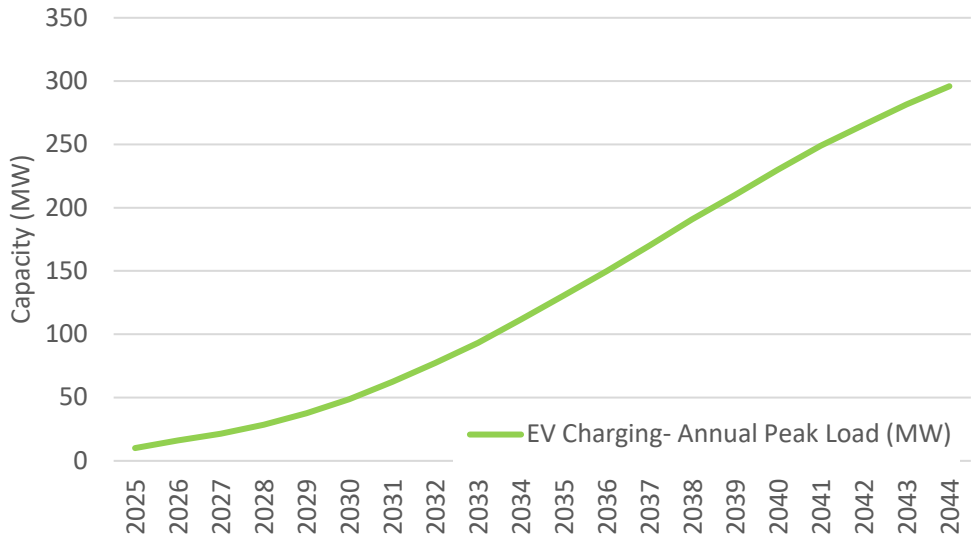
Figure 39: Annual Electricity Use for Light-Duty Vehicle Charging in Puerto Rico



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

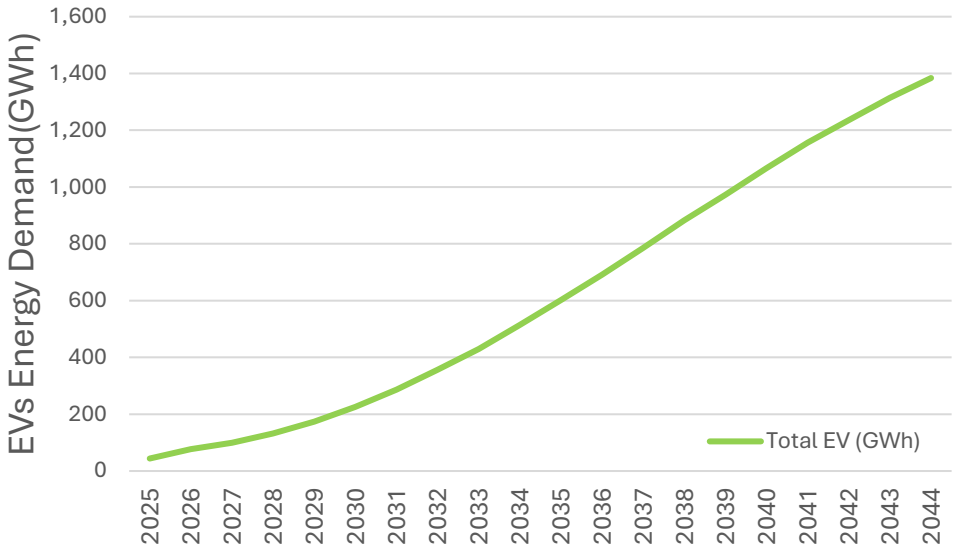
Figure 40 showcases LUMA's impact on the system peak load derived from EVs at peak hour (21:00 hours). This impact includes all types of EVs, including LDV (residential, commercial, and industrial) and MHDV (commercial and industrial), considering that the vehicles are not being charged in workplaces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

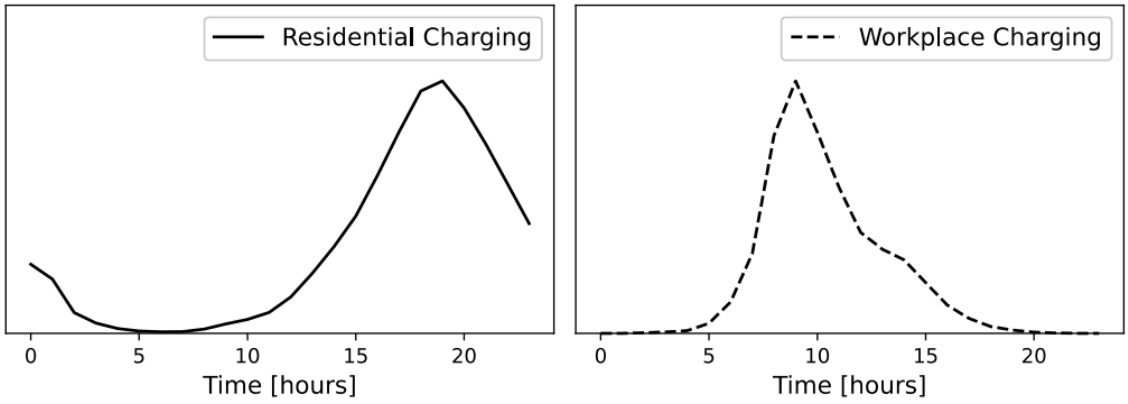


Figure 84. Two light-duty EV unmanaged charging profiles assumed to occur at residential locations (left) and places of work (right)

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.[99] 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,[100] 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

[99] 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

[100] 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[101] 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[102]



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.

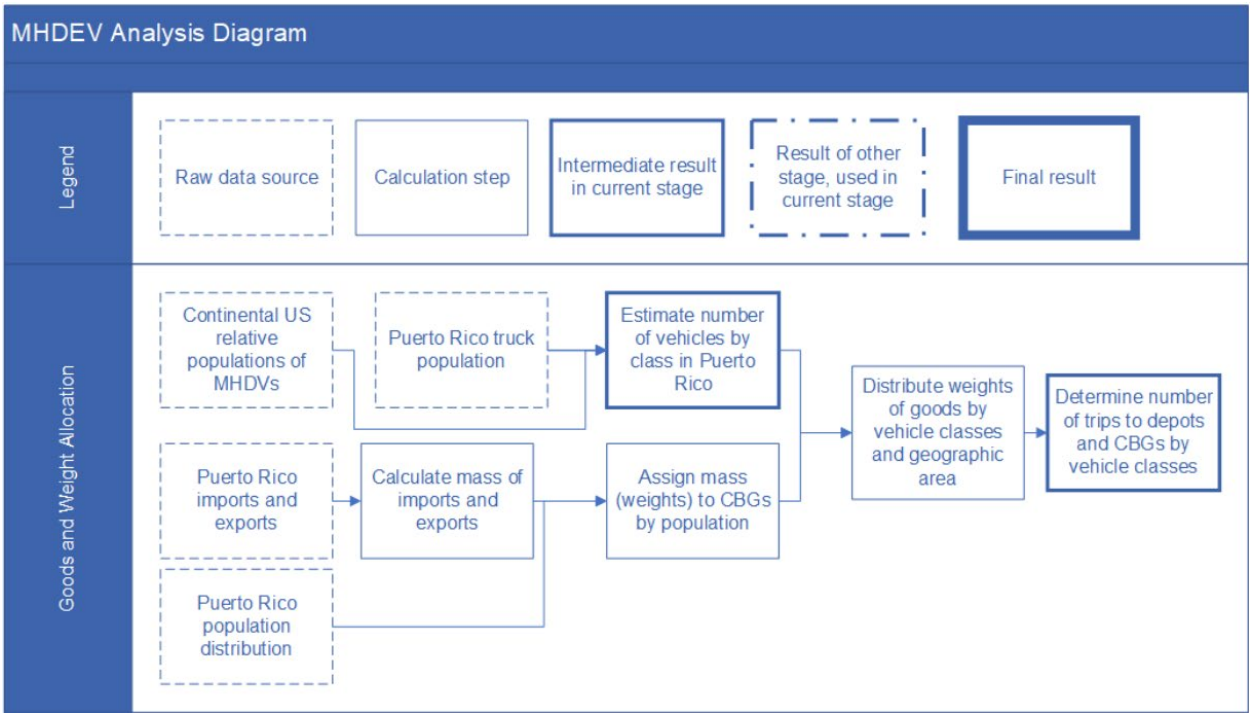
STEP 1. Goods and Weight Allocation: Figure 45 shows the process used to determine the number of trips, by vehicle class, required to transport goods between the Port of San Juan and census block groups (CBGs), via notional depots located at population centers at each municipality. The primary aim of

[101] U.S. Energy Information Administration. (n.d.). Puerto Rico Territory Energy Profile. https://www.eia.gov/state/print.php?sid=RQ
[102] 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

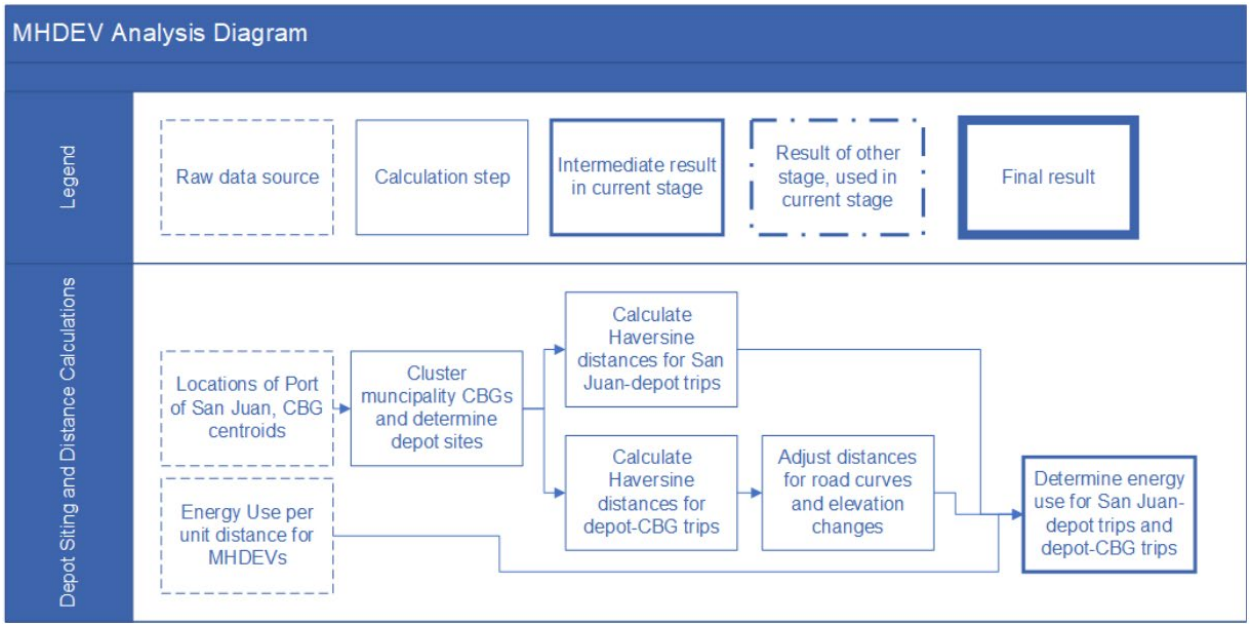


STEP 2. Depot Siting and Distance Calculations: This step (illustrated in Figure 46) was to compute the distances between the Port of San Juan and population centers at each municipality and between population centers and CBGs. This stage aimed to construct a transportation model to estimate distances 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

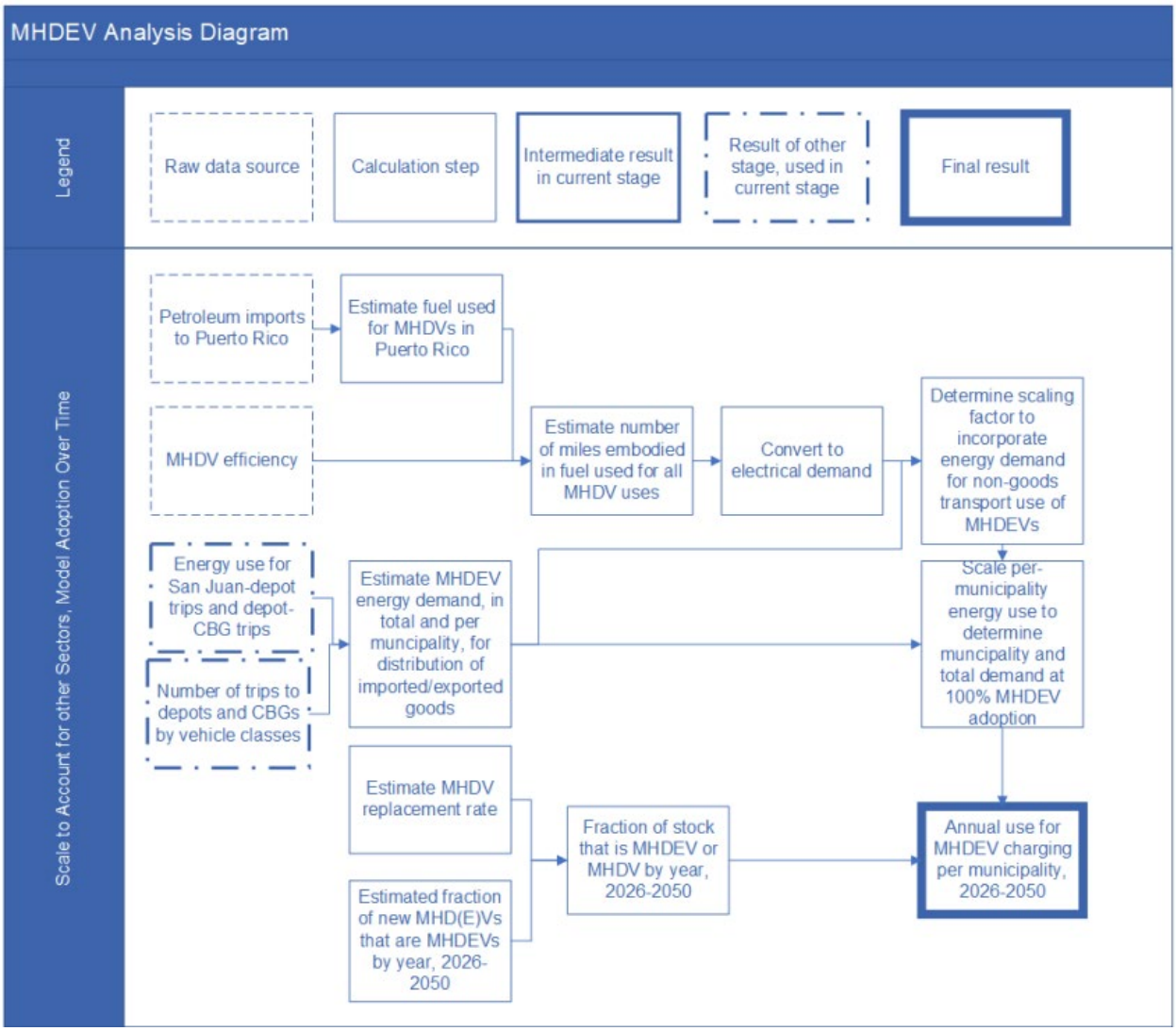
Route	Vehicle Class	Energy Efficiency (kWh/mile)	Route	Vehicle Class	Energy Efficiency (kWh/mile)
San Juan to the municipality depot:	7	1.7	Municipality depot to destination	2b	.5
	8	2.0		3, 4, 5	1.25
				6	1.5

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[103] 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



[103] 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,[104] 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.

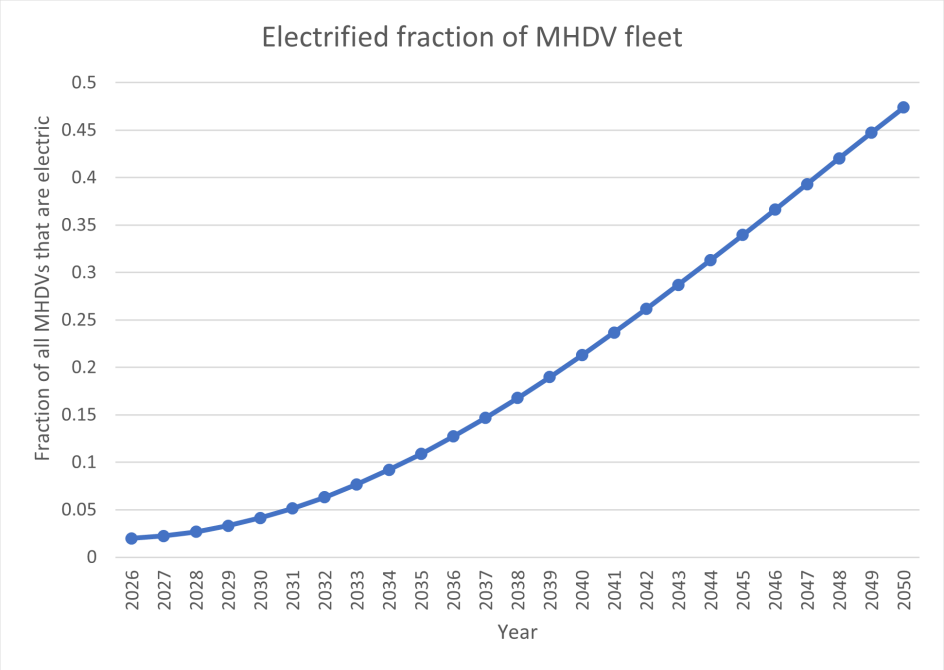
Step 3B. Estimating Electric Vehicle Market Size and Corresponding Charging Load: PR100 estimated the growth of MHDEVs as follows:

- 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.

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

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

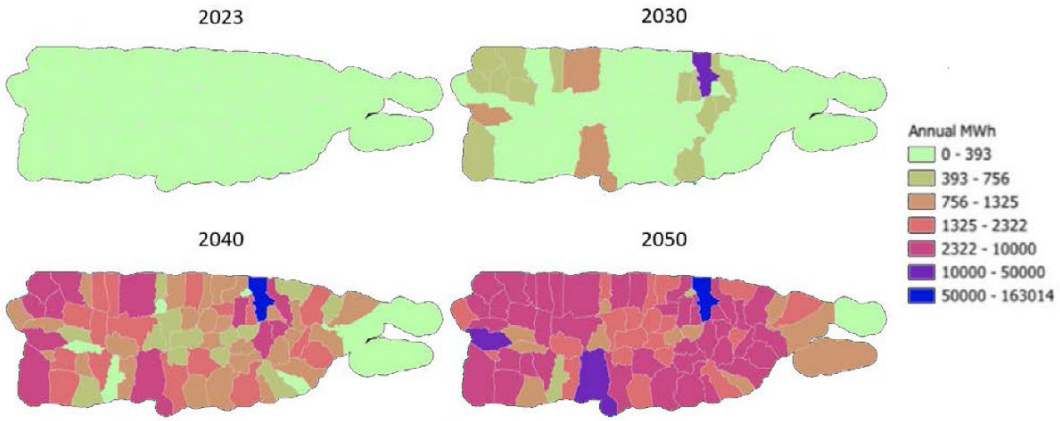
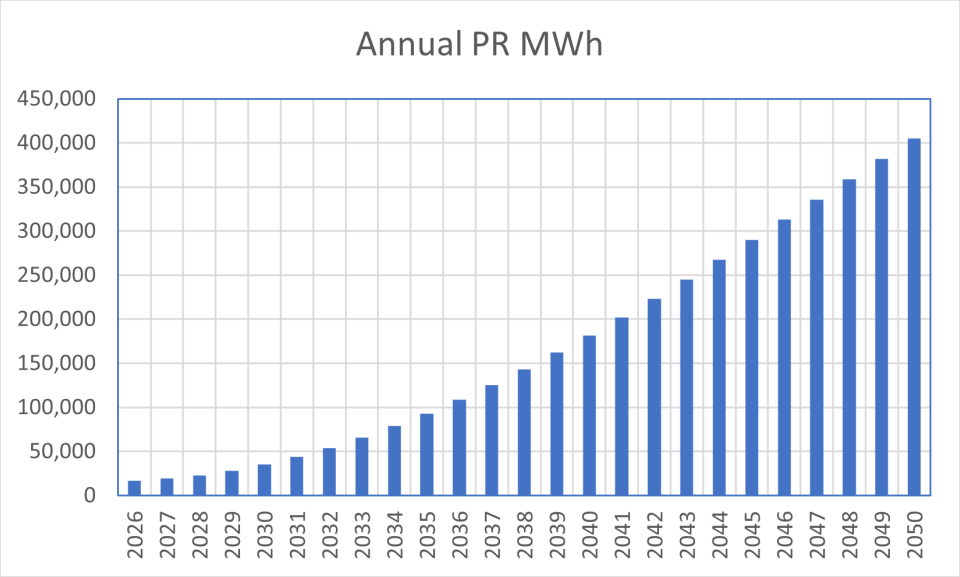


Figure 50: Total Annual Electricity Use by MHDEV in Puerto Rico

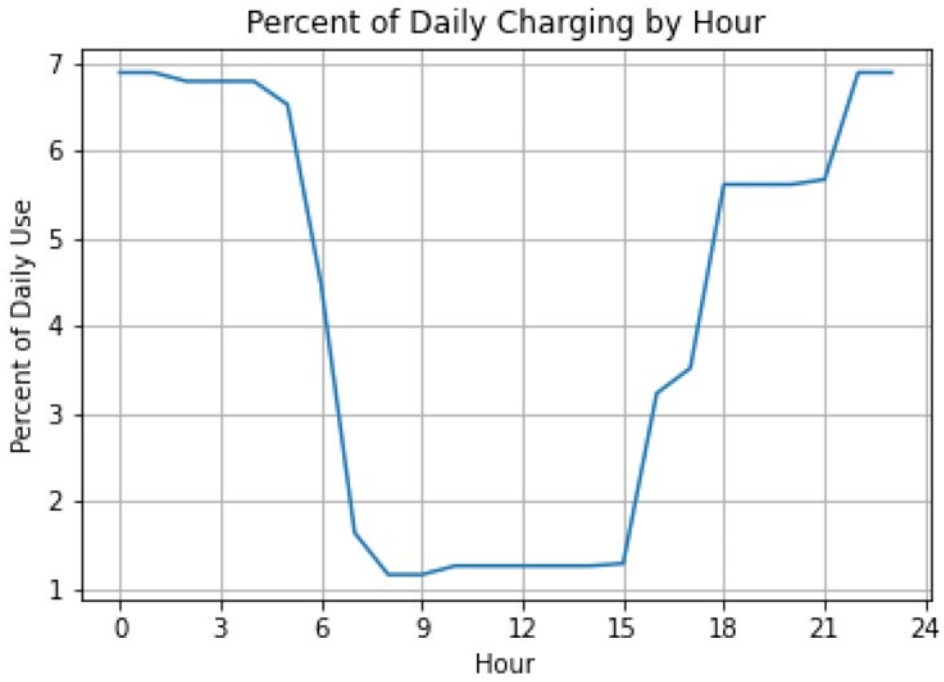


STEP 4. Charging Schedule Estimation: A charging schedule for each MHDV end use is estimated based on the mission, the vehicle miles traveled are estimated for each end use, and a weight factor based on the miles traveled is associated with the charging schedule for each end use, allowing the calculation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

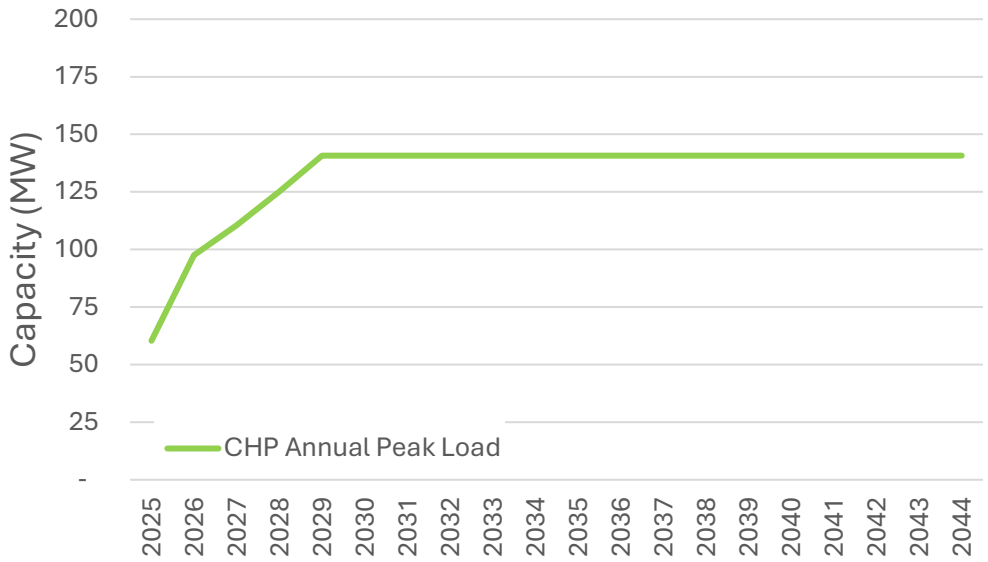
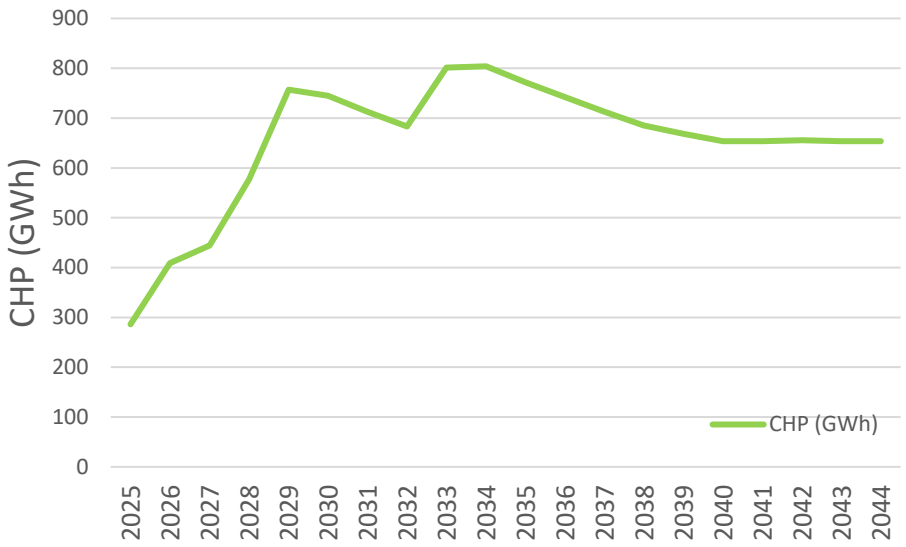


Figure 53 showcases the impact on energy generation (in GWh) associated with the CHP.

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)

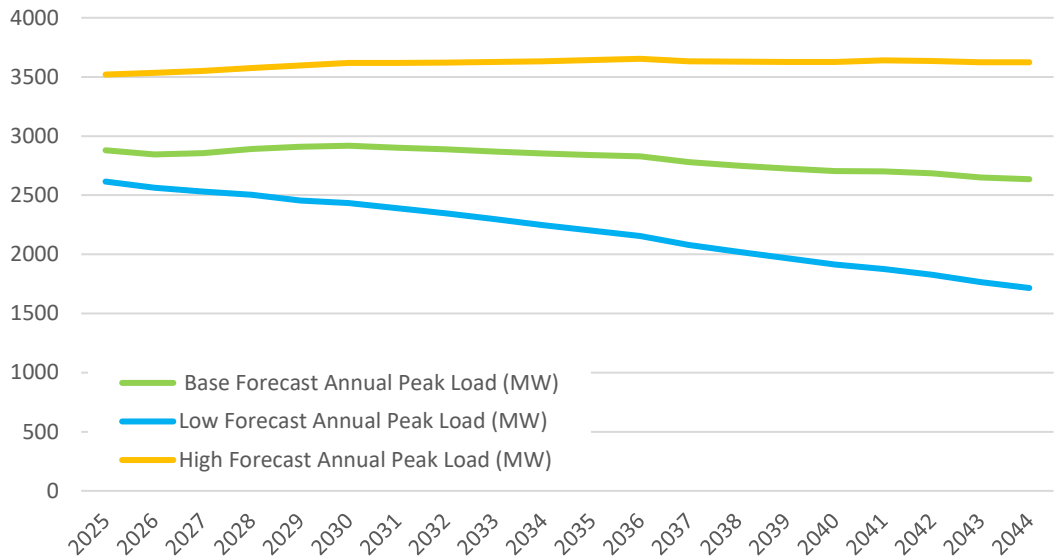


Figure 55 showcases a graph including the core peak load forecasts, adding the base load modifiers. As such, the impact of the load modifiers on the core load forecast can be appreciated if compared with the previous graph (Figure 54).

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

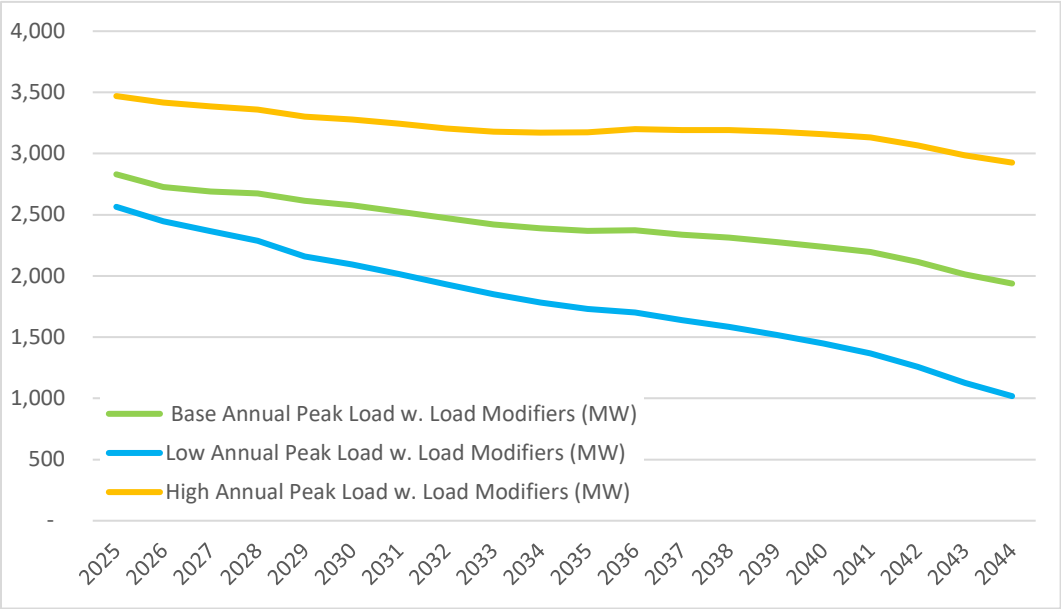


Figure 56 showcases the energy demand for each load forecast (base, low, and high) before applying the different load modifiers.

Figure 56: Core Load Forecast before Modifiers (GWh)

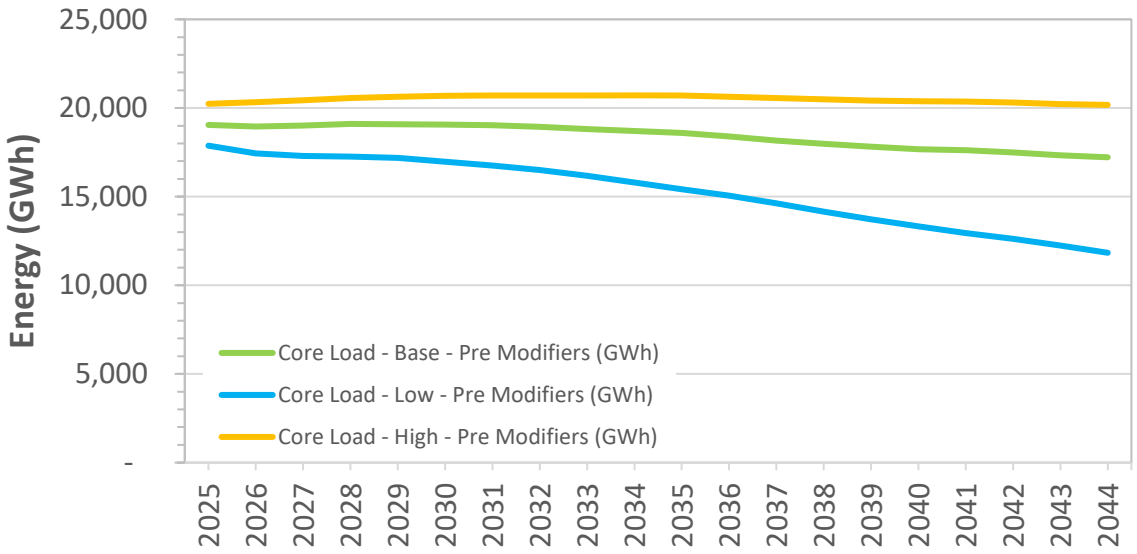
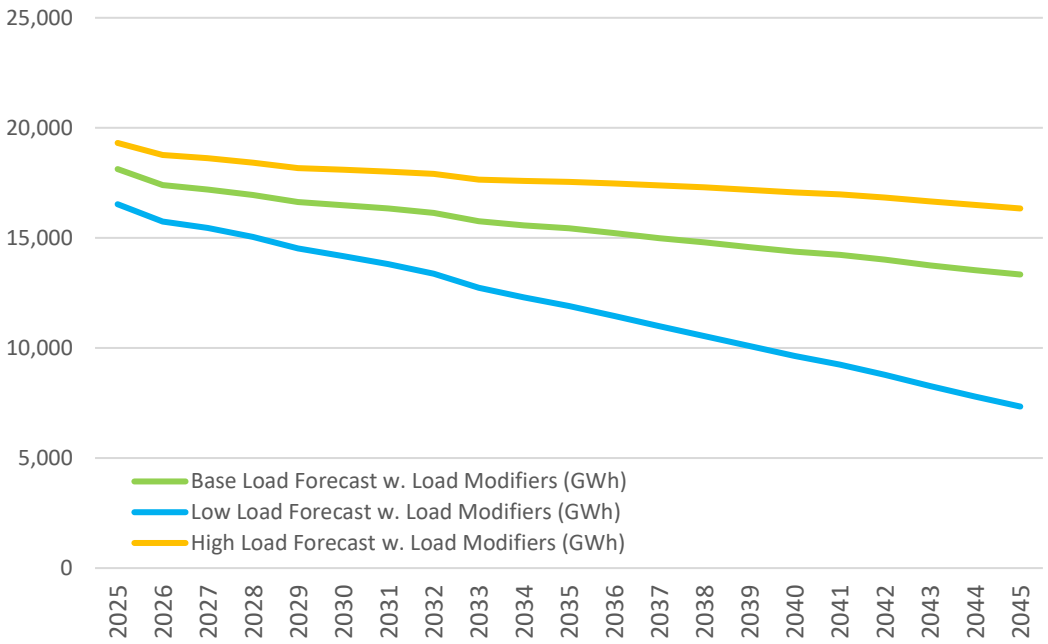


Figure 57 showcases a graph including the core load forecasts, adding the base load modifiers. As such, the impact of the load modifiers on the core load forecast can be appreciated if compared with the previous graph (Figure 56).

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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)[105], 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

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

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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[106] 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

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

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
AES_1	Thermal	Coal	AES, LP	Guayama	2002	2032
AES_2	Thermal	Coal	AES, LP	Guayama	2002	2032
EcoEléctrica	Thermal	Natural gas	EcoEléctrica, LP	Peñuelas	2000	2032
AES Ilumina	Renewable	Solar	AES Ilumina, LLC	Guayama	2012	2032
Fonroche Energy	Renewable	Solar	Fonroche Energy, LLC	Humacao	2021	*2051
Horizon Energy	Renewable	Solar	Horizon Energy Inc	Salinas	2015	2040
San Fermín Solar	Renewable	Solar	Coqui Power, LLC	Loíza	2014	*2040
Cantera Martinó	Renewable	Solar	Windmar	Ponce	2011	2031
Vista Alegre/ Coto Laurel	Renewable	Solar	Windmar	Ponce	2016	2036
Oriana	Renewable	Solar	Yarotek PR, LLC	Isabela	2016	2036
Fajardo Landfill Tech	Renewable	Landfill gas	Landfill Gas Technologies of Fajardo, LLC	Fajardo	2016	2036
Toa Baja Landfill Tech	Renewable	Landfill gas	Landfill Gas Technologies of Fajardo, LLC	Toa Baja	2017	2037
Pattern	Renewable	Wind	Pattern, LLC	Santa Isabel	2016	2051
Punta Lima	Renewable	Wind	Polaris Renewable Energy Inc	Naguabo	2024	2044

*Fonroche's original term was for 20 years, but a 10-year contract extension was agreed.
*San Fermín's original term was 20 years, but a 5-year contract extension was agreed.

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 (%)
Aguirre 1	450	Assumed out of service	10.09	30%
Aguirre 2	450	Assumed out of service	10.3	30%
Costa Sur 5	410	380	10.64	20%
Costa Sur 6	410	360	10.54	20%

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Generator	Nameplate Capacity (MW)	Available Capacity (MW)	Heat Rate (MMBTU/MWh)	Forced Outage Rate (%)
Palo Seco 3	216	180	10.3	25%
Palo Seco 4	216	200	10.3	35%
San Juan 5 CC	220	210	7.79	10%
San Juan 6 CC	220	210	7.69	20%
San Juan 7	100	100	11.88	45%
San Juan 9	100	100	11.55	10%
Aguirre 1 CC	296	165	12.21	50%
Aguirre 2 CC	296	100	12.19	60%
Cambalache 2	82.5	78	13.42	15%
Cambalache 3	82.5	78	13.45	15%
Mayagüez 1	55	50	10.46	30%
Mayagüez 2	55	50	10.55	30%
Mayagüez 3	55	25	10.56	35%
Mayagüez 4	55	25	10.72	35%
GT01 - Palo Seco	21	21	12.26	45%
GT02 - Palo Seco	21	21	12.26	45%
GT11 - Yabucoa	21	21	12.26	45%
GT19 - Jobos	21	21	12.26	45%
GT20 - Jobos	21	21	12.26	45%
GT21 - Daguao	21	21	12.26	45%
GT22 - Daguao	21	21	12.26	45%
Palo Seco Mobile Pack 1	27	27	11.5	50%
Palo Seco Mobile Pack 2	27	27	11.5	50%
Palo Seco Mobile Pack 3	27	27	11.5	50%
Palo Seco TM Gen 4-1	20	20	11.30	15%
Palo Seco TM Gen 4-2	20	20	11.30	15%
Palo Seco TM Gen 6-1	25	25	11.30	15%
Palo Seco TM Gen 6-2	25	25	11.30	15%
San Juan TM Gen 6-1	25	25	10.90	20%
San Juan TM Gen 6-2	25	25	10.90	20%
San Juan TM Gen 6-3	25	25	10.90	20%
San Juan TM Gen 6-4	25	25	10.90	20%
San Juan TM Gen 6-5	25	25	10.90	20%
San Juan TM Gen 6-6	25	25	10.90	20%
San Juan TM Gen 6-7	25	25	10.90	20%
San Juan TM Gen 6-8	25	25	10.90	20%
San Juan TM Gen 6-9	25	25	10.90	20%
San Juan TM Gen 6-10	25	25	10.90	20%
Dos Bocas 2	5	5	N/A	N/Av

Generator	Nameplate Capacity (MW)	Available Capacity (MW)	Heat Rate (MMBTU/MWh)	Forced Outage Rate (%)
Dos Bocas 3	5	5	N/A	N/Av
Garzas 1-1	3.6	3.6	N/A	N/Av
Garzas 1-2	3.6	3.6	N/A	N/Av
Toro Negro 1-1	1.5	1.5	N/A	N/Av
Toro Negro 1-2	1.5	1.5	N/A	N/Av
Toro Negro 1-3	1.5	1.5	N/A	N/Av
Yauco 2-1	4.5	4.5	N/A	N/Av
Yauco 2-2	4.5	4.5	N/A	N/Av

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 (%)
AES 1	227.15	227.15	[redacted]	
AES 2	227.15	227.15		
EcoEléctrica	545	545		
AES Ilumina	20	20		
Fonroche Energy	40	40		
Horizon Energy	10	10		
San Fermín Solar	20	20		
Cantera Martinó	2.1	2.1		
Vista Alegre/Coto Laurel	10	10		
Oriana	45	45		
Fajardo Landfill Tech	2.4	2.4		
Toa Baja Landfill Tech	2.4	2.4		
Pattern	95	95		
Punta Lima	26	26		

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
Aguirre 1	Bunker	[redacted]	[redacted]	$13.32
Aguirre 2	Bunker			$13.32
Costa Sur 5	Natural gas and bunker			$9.23 & $13.32
Costa Sur 6	Natural gas and bunker			$9.23 & $13.32
Palo Seco 3	Bunker			$13.32
Palo Seco 4	Bunker			$13.32
San Juan 5 CC	Natural gas and diesel			$10.23 & $16.50
San Juan 6 CC	Natural gas and diesel			$10.23 & $16.50
San Juan 7	Bunker			$13.32
San Juan 9	Bunker			$13.32
Aguirre 1 CC	Diesel			$16.67
Aguirre 2 CC	Diesel			$16.67
Cambalache 2	Diesel			$16.67
Cambalache 3	Diesel			$16.67
Mayagüez 1	Diesel			$16.67
Mayagüez 2	Diesel			$16.67
Mayagüez 3	Diesel			$16.67
Mayagüez 4	Diesel			$16.67
GT01 – Palo Seco	Diesel			$16.67
GT02 – Palo Seco	Diesel			$16.67
GT11 – Yabucoa	Diesel			$16.67
GT19 – Jobos	Diesel			$16.67
GT20 – Jobos	Diesel			$16.67
GT21 – Daguao	Diesel			$16.67
GT22 – Daguao	Diesel			$16.67
Palo Seco Mobile Pack 1	Diesel			$16.67
Palo Seco Mobile Pack 2	Diesel			$16.67
Palo Seco Mobile Pack 3	Diesel			$16.67
Palo Seco TM Gen 4-1	Natural gas and diesel			$12.05 & $16.67
Palo Seco TM Gen 4-2	Natural gas and diesel			$12.05 & $16.67
Palo Seco TM Gen 6-1	Natural gas and diesel			$12.05 & $16.67
Palo Seco TM Gen 6-2	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-1	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-2	Natural gas and diesel			$12.05 & $16.67

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Generator	Fuel Type	FO&M ($/kW-yr)	VO&M ($/MWh)	Fuel prices ($/MMBtu) (as of May 2025
San Juan TM Gen+6-3	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-4	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-5	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-6	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-7	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-8	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-9	Natural gas and diesel			$12.05 & $16.67
San Juan TM Gen+6-10	Natural gas and diesel			$12.05 & $16.67
Dos Bocas 2	Hydro			N/A
Dos Bocas 3	Hydro			N/A
Garzas 1-1	Hydro			N/A
Garzas 1-2	Hydro			N/A
Toro Negro 1-1	Hydro			N/A
Toro Negro 1-2	Hydro			N/A
Toro Negro 1-3	Hydro			N/A
Yauco 2-1	Hydro			N/A
Yauco 2-2	Hydro			N/A

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
AES_1							
AES_2							
EcoEléctrica							
AES Ilumina							
Fonroche Energy	Solar	$0	$175.15	N/A	$175.15	1%	*2051
Horizon Energy	Solar	$0	$185.31	N/A	$185.31	2%	2040
San Fermín Solar	Solar	$0	$192.50	N/A	$192.50	2%	*2040
Cantera Martinó	Solar	$0	$229.00	N/A	$229.00	2%	2031
Vista Alegre/Coto Laurel	Solar	$0	$201.00	N/A	$201.00	2%	2036
Oriana	Solar	$0	$186.10	N/A	$186.10	2%	2036
Fajardo Landfill Tech	Landfill gas	$0	$100.00	N/A	$100.00	0%	2036
Toa Baja Landfill Tech	Landfill gas	$0	$100.00	N/A	$100.00	0%	2037
Pattern	Wind	$0	$170.38	N/A	$170.38	*Non-fixed	2051

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
Punta Lima	Wind	$0	$149.14	N/A	$149.14	*Non-fixed	2044

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)
2025	$170.38	$149.14
2026	$168.38	$151.02
2027	$170.91	$152.94
2028	$173.47	$154.88
2029	$176.07	$156.85
2030	$173.88	$158.86
2031	$176.49	$160.89
2032	$179.14	$162.95
2033	$181.83	$165.05
2034	$155.32	$167.17
2035	$157.65	$129.36
2036	$160.02	$131.95
2037	$162.42	$134.59
2038	$140.02	$137.28
2039	$141.00	$140.02
2040	$141.00	$141.00
2041	$141.00	$141.00
2042	$141.00	$141.00
2043	$141.00	$141.00
2044	$141.00	
2045	$141.00	
2046	$141.00	
2047	$141.00	

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.[107] 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.

[107] See Energy Bureau Case No. NEPR-MI-2021-0013, In re: The Deployment of Electric Vehicle Charging Infrastructure.

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."*[108] 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*".[109] 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*."[110]

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* […]"[111] 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,

[108] See: https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/2-ingles/17-2019.pdf
[109] See id.
[110] Id.
[111] 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.[112] 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.*"[113] 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.[114]

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

[112] See Act 17-2019, Section 1.9(2); Act 57-2014, as amended, Section 6.23.
[113] Regulation 9021, Section 1.03.
[114] The NERC Reliability Assessment Subcommittee (RAS) defines Reserve Margin (%) = (Resource Capacity – net internal demand)/net internal demand X 100.

operators[115,116,117] 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[118] 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

[115] 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

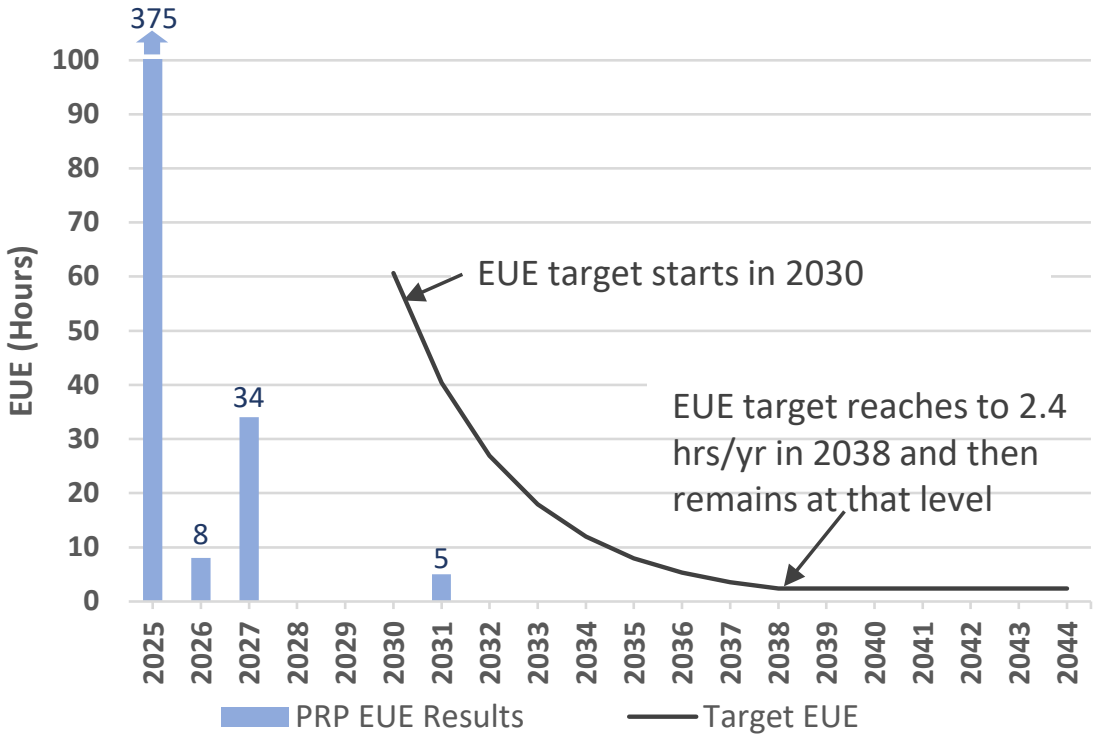
[116] See EPRI Metrics Explainers, https://msites.epri.com/resource-adequacy/metrics/metrics-explainers#4257225834-1165899977

[117] 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.

[118] 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 the 2025 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)[119]	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
CHP	**77**	**101**	**114**	**129**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**	**137**
DR	**0**	**0**	**0**	**3**	**17**	**40**	**76**	**107**	**128**	**143**	**156**	**175**	**202**	**243**	**298**	**356**	**430**	**520**	**610**	**658**
DPV	**254**	**298**	**314**	**333**	**356**	**384**	**418**	**458**	**501**	**543**	**579**	**615**	**658**	**709**	**769**	**839**	**919**	**1,008**	**1,107**	**1,215**
New Distributed Storage			**3**	**8**	**13**	**19**	**21**	**24**	**27**	**30**	**33**	**37**	**41**	**46**	**52**	**57**	**60**	**64**	**68**	**71**
Land Fill Gas Gen	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**2**			
Fajardo Landfill Tech	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2				
Tao Baja Landfill Tech	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2			
Hydro Gen	**4**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**
Hydro Caonillas 2		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Hydro Dos Bocas 1		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Hydro Dos Bocas 2		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Hydro Dos Bocas 3		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Hydro Garzas 1A		6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Hydro Toro Negro 1A		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Hydro Toro Negro 1B		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Hydro Toro Negro 1C		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

[119] 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
Hydro Toro Negro 1D		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Hydro Yauco 2A		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Hydro Yauco 2B	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Peaker Gen	**228**	**228**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**	**81**
GT01-Palo Seco (Diesel)	21	21																		
GT02-Palo Seco (Diesel)	21	21																		
GT03-Palo Seco (Diesel)	21	21																		
GT12-Yabucoa (Diesel)	21	21																		
GT20-Jobos (Diesel)	21	21																		
GT21-Daguao (Diesel)	21	21																		
GT22-Daguao (Diesel)	21	21																		
MG Palo Seco 1 (Diesel Fueled)	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
MG Palo Seco 2 (Diesel Fueled)	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
MG Palo Seco 3 (Diesel Fueled)	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
FEMA Gen	**340**	**340**	**340**	**340**	**340**	**340**	**340**	**340**	**340**	**340**	**265**	**265**	**265**	**265**	**265**	**265**	**265**	**265**	**265**	**265**
FEMA PS Gen 4 #1	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
FEMA PS Gen 4 #2	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
FEMA PS Gen 6 #1	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
FEMA PS Gen 8 #1	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
FEMA SJ Gen+ 6 #1	25	25	25	25	25	25	25	25	25	25										
FEMA SJ Gen+ 6 #10	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
FEMA SJ Gen+ 6 #2	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
FEMA SJ Gen+ 6 #3	25	25	25	25	25	25	25	25	25	25										
FEMA SJ Gen+ 6 #4	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
FEMA SJ Gen+ 6 #5	25	25	25	25	25	25	25	25	25	25										

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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
FEMA SJ Gen+ 6 #6	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
FEMA SJ Gen+ 6 #7	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
FEMA SJ Gen+ 6 #8	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
FEMA SJ Gen+ 6 #9	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Thermal Gen	**3,863**	**3,863**	**3,863**	**4,341**	**4,341**	**4,025**	**3,925**	**3,709**	**3,255**	**3,255**	**2,959**	**2,663**	**2,663**	**2,253**	**1,843**	**1,843**	**1,843**	**1,843**	**1,843**	**1,843**
AES_1	227	227	227	227	227	227	227	227												
AES_2	227	227	227	227	227	227	227	227												
AGUIRRE 1 CC	296	296	296	296	296	296	296	296	296	296	296									
AGUIRRE 2 CC	296	296	296	296	296	296	296	296	296	296										
CAMBALACHE CT_2	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
CAMBALACHE CT_3	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
COSTA SUR 5	410	410	410	410	410	410	410	410	410	410	410	410	410	410						
COSTA SUR 6	410	410	410	410	410	410	410	410	410	410	410	410	410							
ECOELECTRICA	545	545	545	545	545	545	545	545	545	545	545	545	545	545	545	545	545	545	545	545
MAYAGUEZ GT 1	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
MAYAGUEZ GT 2	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
MAYAGUEZ GT 3	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
MAYAGUEZ GT 4	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
PALO SECO 3	216	216	216	216	216	216	216													
PALO SECO 4	216	216	216	216	216															
SAN JUAN 460MW CC				478	478	478	478	478	478	478	478	478	478	478	478	478	478	478	478	478
SAN JUAN 5 CC	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
SAN JUAN 6 CC	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
SAN JUAN 7	100	100	100	100	100															
SAN JUAN 9	100	100	100	100	100	100														
Emergency Generator		**800**	**800**	**800**																
Aguirre_EG1		33	33	33																
Aguirre_EG1 1		33	33	33																

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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
Aguirre_EG1 2		33	33	33																
Aguirre_EG1 3		33	33	33																
Aguirre_EG1 4		33	33	33																
Aguirre_EG1 5		33	33	33																
Aguirre_EG2		33	33	33																
Aguirre_EG2 1		33	33	33																
Aguirre_EG2 2		33	33	33																
Aguirre_EG2 3		33	33	33																
Aguirre_EG2 4		33	33	33																
Aguirre_EG2 5		33	33	33																
Costa Sur_EG1		33	33	33																
Costa Sur_EG1 1		33	33	33																
Costa Sur_EG1 2		33	33	33																
Costa Sur_EG1 3		33	33	33																
Costa Sur_EG1 4		33	33	33																
Costa Sur_EG1 5		33	33	33																
Costa Sur_EG2		33	33	33																
Costa Sur_EG2 1		33	33	33																
Costa Sur_EG2 2		33	33	33																
Costa Sur_EG2 3		33	33	33																
Costa Sur_EG2 4		33	33	33																
Costa Sur_EG2 5		33	33	33																
New Genera Units		**272**	**674**	**674**	**674**	**674**	**674**	**674**	**674**	**674**	**638**	**638**	**638**	**638**	**466**	**466**	**466**	**466**	**466**	**430**
2X17MW 18V50DF Jobos			36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	
2X17MW 18V50DF Yabucoa			36	36	36	36	36	36	36	36										
2X50MW Costa Sur			136	136	136	136	136	136	136	136	136	136	136	136						
2X9MW 18V50DF Daguao			36	36	36	36	36	36	36	36	36	36	36	36						

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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
Aguirre - 4HR			158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158
Cambalache - 4HR		52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Costa Sur - 4HR		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Palo Seco - 4HR		101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Vega Baja - 4HR		49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Yabucoa - 4HR		40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
New Gas Gen							**104**	**104**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**104**	**104**	**104**	**104**	**104**
7F.05 1x1_S Juan									373	373	373	373	373	373	373					
LM2500 1x0_Arecibo							35	35	35	35	35	35	35	35	35	35	35	35	35	35
LM2500 1x0_Ponce OE							35	35	35	35	35	35	35	35	35	35	35	35	35	35
LM2500 1x0_S Juan							35	35	35	35	35	35	35	35	35	35	35	35	35	35
Biodiesel Conversions											**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**
Biodiesel FEMA SJ Gen+ 6 #1											25	25	25	25	25	25	25	25	25	25
Biodiesel FEMA SJ Gen+ 6 #3											25	25	25	25	25	25	25	25	25	25
Biodiesel FEMA SJ Gen+ 6 #5											25	25	25	25	25	25	25	25	25	25
New Gas Gen Biodiesel													**453**	**453**	**453**	**826**	**826**	**826**	**826**	**826**
7F.05 1x0_Bayamon Biodiesel													226	226	226	226	226	226	226	226
7F.05 1x0_S Juan Biodiesel													226	226	226	226	226	226	226	226
7F.05 1x1_S Juan Biodiesel																373	373	373	373	373
New Genera Units Biodiesel											**36**	**36**	**36**	**36**	**208**	**208**	**208**	**208**	**208**	**244**
2X17MW 18V50DF Jobos Biodiesel																				36
2X17MW 18V50DF Yabucoa Biodiesel											36	36	36	36	36	36	36	36	36	36

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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
2X50MW Costa Sur Biodiesel															136	136	136	136	136	136
2X9MW 18V50DF Daguao Biodiesel															36	36	36	36	36	36
Tranche 1 Solar	**35**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**	**739**
AES Jobos Solar		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
AES Salinas Solar		120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Ciro Two Salinas		68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Coamo Solar		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Guayama Solar Energy		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Juncos I PV		125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Pattern Barceloneta Solar ITC		70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Solaner San German	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Tetris Power		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Yabucoa		32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
Yabucoa Energy Park Solar ITC		39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Tranche 2 Solar			**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**
Marisol Power			40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Solar Project San Juan			26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Solar	**237**	**287**	**287**	**347**	**347**	**347**	**347**	**345**	**325**	**325**	**325**	**295**	**240**	**240**	**240**	**240**	**240**	**240**	**240**	**240**
AES Illumina	20	20	20	20	20	20	20	20												
Fonroche Energy (Humacao Solar Project)	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Horizon Energy	10	10	10	10	10	10	10	10	10	10	10									
San Fermin Solar	20	20	20	20	20	20	20	20	20	20	20									
Solar Ciro One	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Solar Ciro One Phase 2		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50

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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
Solar Xzerta-Tec				60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Windmar (Cantera Martino)	2	2	2	2	2	2	2													
Windmar (Vista Alegre/Coto Laurel)	10	10	10	10	10	10	10	10	10	10	10	10								
Yarotek (Oriana)	45	45	45	45	45	45	45	45	45	45	45	45								
Wind Gen	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**
Go Green (Punta Lima)	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Pattern (Pattern Santa Isabel)	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Tranche 1 BESS		**435**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**
AES Jobos (BESS)- ITC		110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
AES Salinas (BESS)- ITC		175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Caguas Energy Storage		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Pattern Barceloneta STORAGE			50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Pattern Santa Isabel Storage			50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Peñuelas Energy Storage		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Ponce Energy Storage		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Tranche 2 BESS			**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**
Vega Baja BESS			60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Tranche 4 BESS			**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
Isabela BESS (6-hour)			50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
ASAP Phase 1		**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**
EcoEléctrica 4hr BESS		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Fonroche Humacao Solar 4hr BESS		40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Horizon Energy BESS_Phase1		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20

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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
Punta Lima Wind Farm BESS_Phase1		40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
San Fermin Solar Farm BESS_Phase1		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Yarotek (Oriana) 4hr BESS		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
ASAP Phase 2							**418**	**418**	**418**	**418**	**418**	**418**	**425**	**425**	**425**	**425**	**425**	**425**	**425**	**425**
Ciro ONE 4hr BESS Phase 2							98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ciro Two BESS_Phase2							48	48	48	48	48	48	48	48	48	48	48	48	48	48
Fonroche Humacao Solar 4hr BESS Phase 2							28	28	28	28	28	28	28	28	28	28	28	28	28	28
Guayama Solar Energy BESS_Phase2							35	35	35	35	35	35	35	35	35	35	35	35	35	35
Juncos I PV BESS_Phase2							3	3	3	3	3	3	3	3	3	3	3	3	3	3
Landfill Gas Technologies Fajardo BESS_Phase2							7	7	7	7	7	7	7	7	7	7	7	7	7	7
Landfill Gas Technologies Toa Baja BESS_Phase2													7	7	7	7	7	7	7	7
Punta Lima Wind Farm BESS_Phase2							28	28	28	28	28	28	28	28	28	28	28	28	28	28
San Fermin Solar Farm BESS_Phase2							53	53	53	53	53	53	53	53	53	53	53	53	53	53
Solaner BESS_PHase2							28	28	28	28	28	28	28	28	28	28	28	28	28	28
Tetris Power BESS_Phase2							14	14	14	14	14	14	14	14	14	14	14	14	14	14
XZERTA-TEC BESS_Phase2							42	42	42	42	42	42	42	42	42	42	42	42	42	42
Yabucoa YFN BESS_Phase2							35	35	35	35	35	35	35	35	35	35	35	35	35	35

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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
Regulation Only BESS (4x25)				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
Aguadilla				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Barceloneta				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Manati				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
San Juan				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Grand Total	**5,164**	**7,721**	**8,284**	**8,964**	**8,214**	**7,954**	**8,448**	**8,303**	**8,270**	**8,331**	**8,087**	**7,819**	**8,298**	**7,984**	**7,695**	**7,829**	**7,984**	**8,164**	**8,357**	**8,516**

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[120]. 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
CIRO One-Phase 1	Solar PV	Solar	Ponce ES	90	Aug-25	-			
CIRO One-Phase 2	Solar PV	Solar	Ponce ES	50	May-26	-			

[120] 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
Xzerta Tec	Solar PV	Solar	Arecibo	60	Oct-27	-			
Energiza	Combined cycle unit	Natural gas	San Juan	478	Jun-28	[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 (%)
AES Jobos Solar	Solar PV	Ponce ES	80	Sep-26	Clean Flexible Energy	$0.1057	-	2%
AES Jobos (BESS)- ITC	BESS	Ponce ES	110	Sep-26	Clean Flexible Energy	-	$25,117	2%
AES Salinas Solar	Solar PV	Ponce ES	120	Mar-26	Clean Flexible Energy	$0.1061	-	2%
AES Salinas (BESS)- ITC	BESS	Ponce ES	175	Mar-26	Clean Flexible Energy	-	$25,096	2%
Pattern Barceloneta Solar ITC	Solar PV	Arecibo	70	Mar-26	Pattern Energy	$0.1531	-	0%
Ciro Two Salinas	Solar PV	Ponce ES	68	May-26	Putnam Bridge	$0.0955	-	2%
Guayama Solar Energy	Solar PV	Ponce ES	50	Mar-26	Putnam Bridge	$0.1005	-	2%
Yabucoa YFN	Solar PV	Caguas	32.1	May-26	YFN Sonnedix Solar Puerto Rico, LLC	$0.1469	-	2%
Yabucoa Energy Park Solar ITC	Solar PV	Caguas	38.7	Aug-26	Go Green	$0.1397	-	0%
Tetris Power	Solar PV	Carolina	20	Mar-26	Yarotek PR, LLC	$0.1385	-	1%
Coamo Solar	Solar PV	Ponce ES	100	May-26	Convergent Energy and Power LLC	$0.1000	-	2%

Project Name	Resource Type	Location	Capacity	COD	Owner	PPOA Price ($/kWh)	Monthly Capacity Payment Price ($/MW-month)	Escalator (%)
Caguas Energy Storage	BESS	Caguas	25	Mar-26	Convergent Energy and Power LLC	-	$28,524.36	2%
Peñuelas Energy Storage	BESS	Ponce OE	100	May-26	Convergent Energy and Power LLC	-	$28,669.75	2%
Ponce Energy Storage	BESS	Ponce OE	25	Mar-26	Convergent Energy and Power LLC	-	$27,236.95	2%
Solaner San Germán	Solar PV	Mayagüez	25	Sep-25	Solaner Puerto Rico One, LLC	$0.1219	-	2%
Juncos Solar	Solar PV	Caguas	125	Nov-25		$0.1360	-	0%
Pattern Barceloneta BESS	BESS	Arecibo	50	Feb-25	Pattern Energy	-	$25,854	2%
Pattern Santa Isabel BESS	BESS	Ponce ES	50	Apr-27	Pattern Energy	-	$26,673	2%

Table 55: Tranche 2 Projects

Project Name	Resource Type	Location	Capacity	COD	Owner	PPOA Price ($/kWh)	Monthly Capacity Payment Price ($/MW-month)	Escalator (%)
San Juan Solar	Solar PV	Caguas	26.07	Aug-27	Fonroche	$0.1450	-	0%
Marisol Solar	Solar PV	Ponce ES	40	Aug-27	Yarotek PR, LLC	$0.1530	-	0%
Vega Baja BESS	BESS	Arecibo	60	Aug-27	Canadian Solar - Uriel	-	[redacted]	0%

Table 56: Tranche 4 Projects

Project Name	Resource Type	Location	Capacity	COD	Owner	Monthly Capacity Payment Price ($/MW-month)	Escalator (%)
Isabela BESS	BESS (6-hr)	Arecibo	50	Aug-27	Infinigen	[redacted]	0%

6.1.3 Genera Fixed Units (Thermal and BESS units)

Genera PR is promoting the development of energy generation projects listed in Table 57 that include both thermal and BESS.[121] LUMA expects that these projects will strengthen Puerto Rico's energy system by improving the grid's reliability and resiliency.

[121] See Puerto Rico Energy Bureau Case Number NEPR-MI-2021-0002, In re: Review of the Puerto Rico Electric Power Authority's 10-Year Infrastructure Plan – December 2020.

Table 57: Genera Thermal and BESS Units

Project Name	Resource Type	Location	Capacity	COD	Owner
Costa Sur	Peaker unit- natural gas	Ponce OE	136	2027	Genera
Daguao	Peaker unit- natural gas	Caguas	36	2027	Genera
Jobos	Peaker unit- natural gas	Ponce ES	36	2027	Genera
Yabucoa	Peaker unit- natural gas	Caguas	36	2027	Genera
Aguirre	BESS	Ponce ES	158	2027	Genera
Cambalache	BESS	Arecibo	52	2025	Genera
Costa Sur	BESS	Ponce OE	30	2025	Genera
Palo Seco	BESS	Bayamon	101	2026	Genera
Vega Baja	BESS	Arecibo	49	2025	Genera
Yabucoa	BESS	Caguas	40	2026	Genera

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.[122] 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
EcoEléctrica	BESS	Ponce OE	20	May-26		
Horizon Energy	BESS	Ponce ES	20	May-26		
Oriana Energy	BESS	Arecibo	50	May-26		
San Fermín Solar Farm	BESS	Carolina	20	May-26		
Punta Lima Wind Farm	BESS	Caguas	40	May-26		
Fonroche	BESS	Caguas	40	May-26		
Punta Lima Wind Farm	BESS	Caguas	40	Dec-26		
Landfill Gas Technologies Fajardo	BESS	Carolina	10	Dec-26		
Landfill Gas Technologies Toa Baja	BESS	Arecibo	10	Dec-26		
San Fermín Solar Farm	BESS	Carolina	75	Dec-26		
Fonroche	BESS	Caguas	40	Dec-26		
CS-UR JUNCOS PV (Juncos I PV)	BESS	Caguas	4	Dec-26		
Xzerta-Tec	BESS	Arecibo	60	Dec-26		
Solaner	BESS	Mayagüez	40	Dec-26		
Yabucoa YFN	BESS	Carolina	50	Dec-26		
Tetris Power	BESS	Caguas	20	Dec-26		
Ciro One	BESS	Ponce ES	140	Dec-26		
Ciro Two	BESS	Ponce ES	68	Dec-26		
Guayama Solar Energy	BESS	Ponce ES	50	Dec-26		

*Please note that LUMA will consider only the70% of the total capacity of each of the ASAP Phase 2 units (COD on Dec 2026) included in the 2025 IRP, since it is assumed that 30% of the projects will not go forward.

[122] See Case Number NEPR-MI-2024-0002, In re: LUMA's Accelerated Storage Addition Program ("ASAP").

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.[123] 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.[124] 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.[125] 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.

[123] See Puerto Rico Energy Bureau Case Number NEPR-MI-2024-0005, In re: Electric System Priority Stabilization Plan.
[124] See Puerto Rico Energy Bureau Case Number NEPR-AP-2025-0003, In re: Petition for approval of amendment to PPA between Energiza, LLC and PREPA.
[125] Approved by the Energy Bureau in Case No. NEPR-MI-2022, In re: Review of the Puerto Rico Electric Power Authority’s 10-Year Infrastructure Plan- December 2020.

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 2. DBESS and UBESS 3. Distributed and utility-scale solar PV 4. Geothermal 5. Hydroelectric 6. Hydrogen 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)	1. Liquefied natural gas 2. Biodiesel 3. Distributed and utility-scale solar PV 4. DBESS and UBESS 5. Hydroelectric 6. Wind (onshore)

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% of 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.[126] 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.

[126] Approved by the Energy Bureau in Case Number NEPR-MI-2022-0001, In re: Energy Efficiency and Demand Response Transition Period Plan.

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.[127] 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.[128]

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.

[127] Diversegy. (2023). What are distributed energy resources (DERs)? https://diversegy.com/distributed-energy-resources/
[128] 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/

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 settled annually.[129] 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.

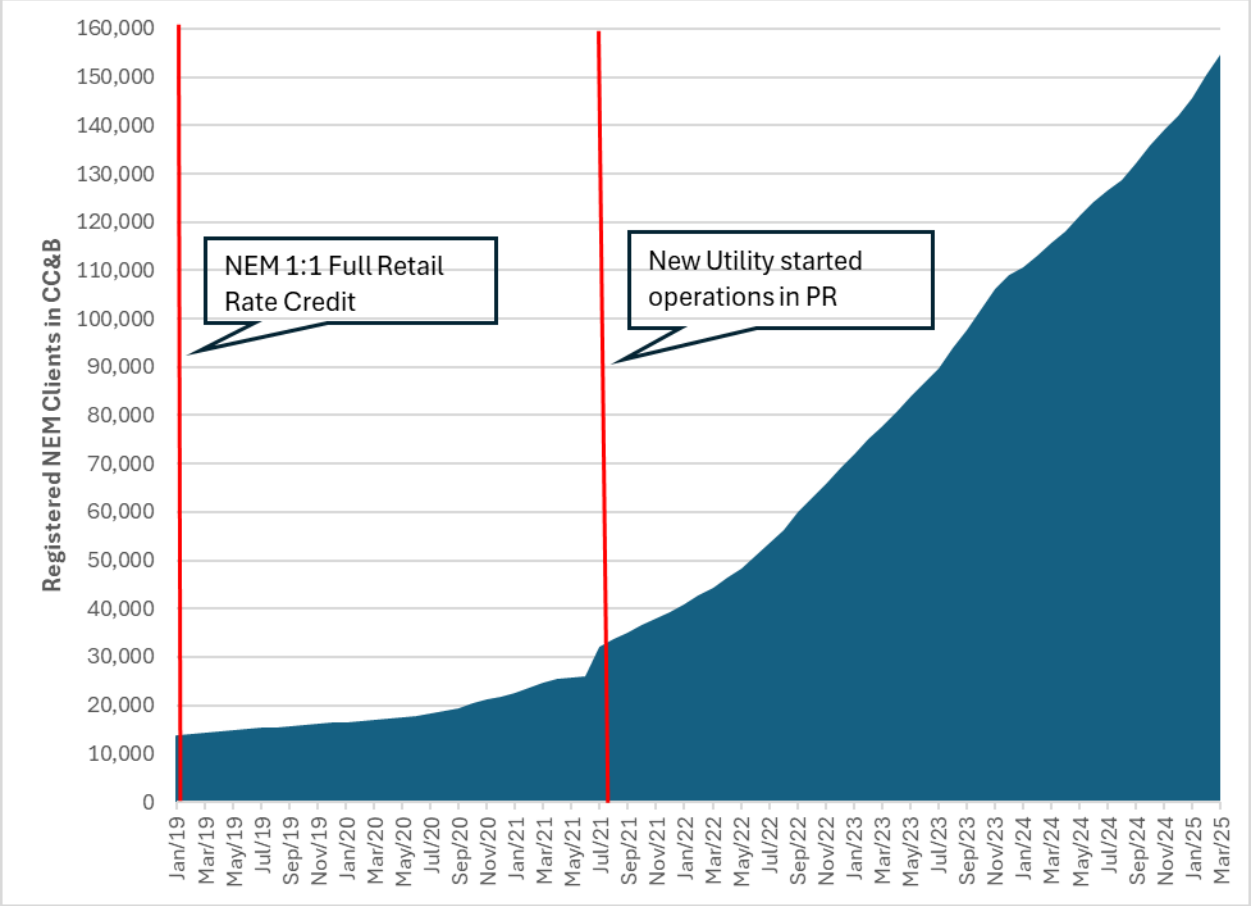
As of March 2025, over 140,000 residential customer accounts in Puerto Rico are equipped with PV systems. Between fiscal year (FY) 2021 and FY2025, approximately 68% of these customers also installed BESS, with adoption accelerating sharply in recent years. Notably, in FY2024 and FY2025, nine out of 10 new PV installations have included battery storage.[130]

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.[131] 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.

[129] 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
[130] Internal Utility Data as of March 2025
[131] 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.[132] 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.

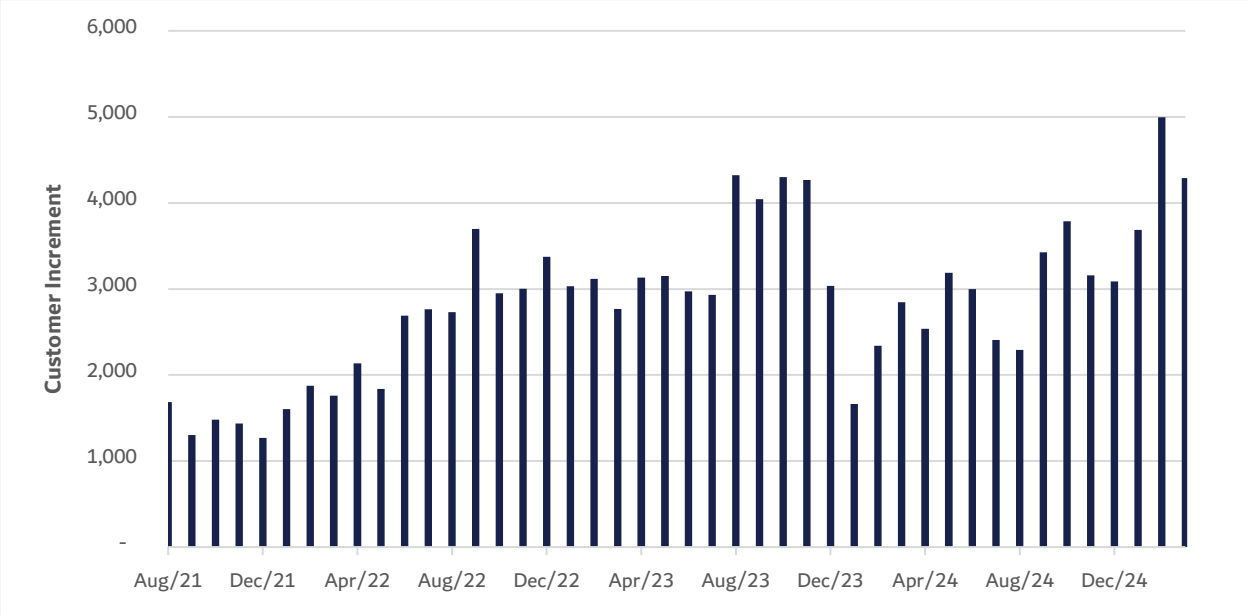
In June 2021, LUMA took over interconnections for DG systems, leading to a marked increase in residential installations.[133] Since assuming responsibility for DG interconnections in June 2021, LUMA has implemented operational efficiencies that significantly improved processing times and reduced the 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

[132] 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
[133] 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.[134] 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.[135]

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

[134]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

[135] 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.[136] 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,[137] 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.[138] 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

[136] 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.*
[137] 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
[138] 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.

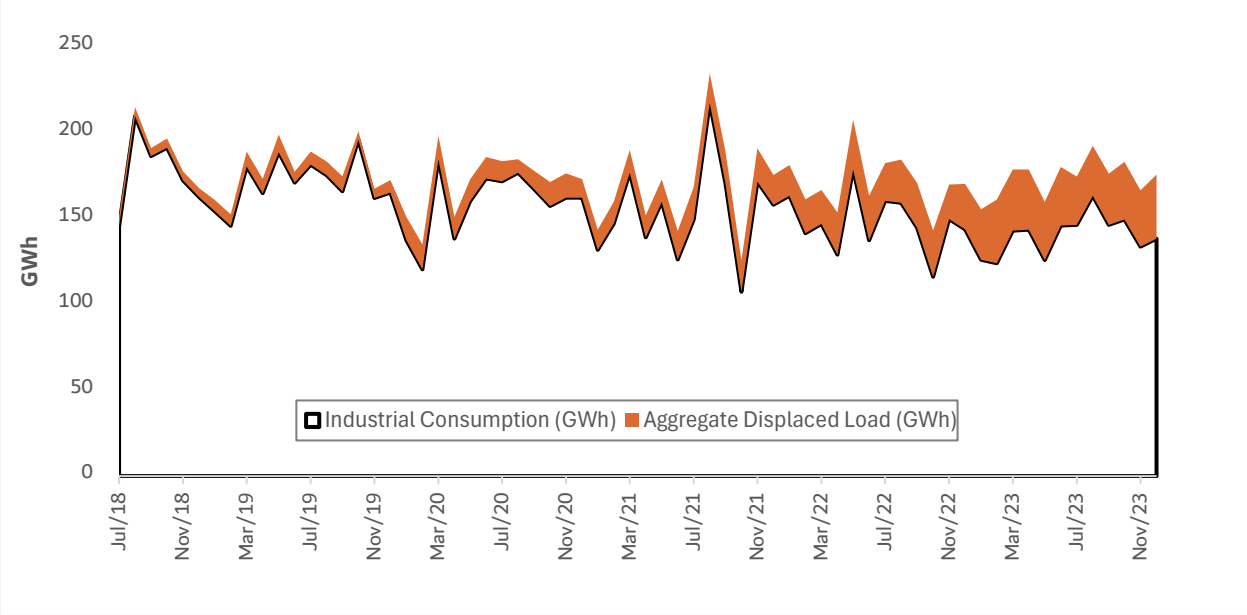
6.5.4 Combined Heat and Power Potential Grid Defection

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.[139]

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.[140] [141] 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.[142] 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.

[139] 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.
[140] 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/
[141] 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/
[142] 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
2024	8.49	9.49	5.86	16.63	19.92	27.74	39.7
2025	9.92	10.92	6.73	15.68	18.93	27.10	38.9
2026	10.62	11.62	6.27	15.24	18.37	26.63	38
2027	10.89	11.89	6.05	15.74	18.03	26.43	37.5
2028	10.89	11.89	5.99	16.21	17.82	26.10	36.8
2029	10.86	11.86	6.08	16.64	18.28	26.85	37.3
2030	10.63	11.63	6.22	17.11	18.69	27.45	37.8
2031	10.98	11.98	6.34	17.59	19.24	28.14	38.2
2032	11.41	12.41	6.39	18.09	19.76	28.90	38.7
2033	11.94	12.94	6.50	18.62	20.33	29.62	39.1
2034	12.39	13.39	6.65	19.17	20.85	30.43	39.7
2035	12.77	13.77	6.78	19.75	21.49	31.25	40.3

Year	EcoEléctrica	LNG SJ	Coal	Heavy Fuel Oil	Diesel	Biodiesel	Renewable Diesel
2036	12.96	13.96	6.92	20.28	22.0	32.02	40.8
2037	13.22	14.22	7.06	20.84	22.60	32.80	41.4
2038	13.66	14.66	7.32	21.41	23.17	33.56	41.9
2039	13.67	14.67	7.46	21.97	23.72	34.36	42.4
2040	14.18	15.18	7.63	22.54	24.29	35.08	43
2041	14.56	15.56	7.80	23.18	24.98	36.01	43.7
2042	14.75	15.75	7.97	23.72	25.54	36.78	44.3
2043	14.81	15.81	8.15	24.36	26.25	37.71	44.9
2044	14.93	15.93	8.32	24.90	26.77	38.47	45.5

*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.[143]

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.

[143] 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."[144] 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.[145] 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.[146] 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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[144] 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

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

[146] 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 $0.80 per 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 Table 65, 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%

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
2028	108%	108%	158%	112%	112%
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	2.16	$1,739	$30.07	$47.74
2027	2.08	$1,613	$28.34	$46.55
2028	1.99	$1,489	$26.62	$45.31
2029	1.91	$1,367	$24.94	$44.03
2030	1.82	$1,249	$23.28	$42.69
2031	1.73	$1,198	$22.37	$41.30
2032	1.65	$1,145	$21.44	$39.84
2033	1.56	$1,092	$20.49	$38.33
2034	1.48	$1,037	$19.52	$36.76
2035	1.39	$983	$18.53	$35.14
2036	1.39	$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	2.16	$4,276	$103.10	$53.00
2027	2.08	$4,135	$98.44	$51.68
2028	1.99	$3,991	$93.78	$50.31
2029	1.91	$3,845	$89.13	$48.88
2030	1.82	$3,697	$84.50	$47.40
2031	1.73	$3,576	$81.74	$45.85
2032	1.65	$3,450	$78.86	$44.24
2033	1.56	$3,319	$75.87	$42.56
2034	1.48	$3,183	$72.76	$40.82
2035	1.39	$4,286	$64.34	$39.02
2036	1.39	$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	2.16	-	-	-
2027	2.08	-	-	-
2028	1.99	-	-	-
2029	1.91	-	-	-
2030	1.82	$8,338	$136.25	$20.53
2031	1.73	$7,957	$128.35	$19.85
2032	1.65	$7,571	$120.50	$19.15
2033	1.56	$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	1.48	$6,790	$105.05	$17.67
2035	1.39	$6,398	$97.48	$16.89
2036	1.39	$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 turbines (GT) and combined cycle gas turbines (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[147] 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.[148]

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

[147][147] Sargent & Lundy's 2021 report to FEMA on the feasibility of locating a new CC plant at Palo Seco
[148] 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
1	San Juan	Bayamón	5	-	$4,036,007		-	$2,722,709	
2	Bayamón	Arecibo	37	$2,425,272	-		$2,057,372	-	
3	Arecibo	Mayagüez	33	$2,423,988	-		$2,054,874	-	
4	Mayagüez	Ponce OE	31	$2,427,259	-		$2,060,008	-	
5	Ponce OE	Ponce ES	40		$3,993,739		-	$2,561,435	
6	Ponce ES	Caguas	20	$2,429,967	-		$2,064,047	-	
7	Caguas	Carolina	12	$2,435,530	-		$2,071,366	-	
8	Carolina	San Juan	11	$2,434,254	-		$2,065,426	-	
9	Caguas	San Juan	10	$2,592,452	-		$2,071,468	-	
10	Caguas	Bayamón	13	$2,402,058	-		$2,067,994	-	
11	Ponce ES	Bayamón	30	-	$3,992,868		-	$2,562,193	
12	Ponce ES	Arecibo	50	$2,423,005	-		$2,055,212	-	
13	Ponce OE	Arecibo	31	$2,427,259	-		$2,187,441	-	

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.

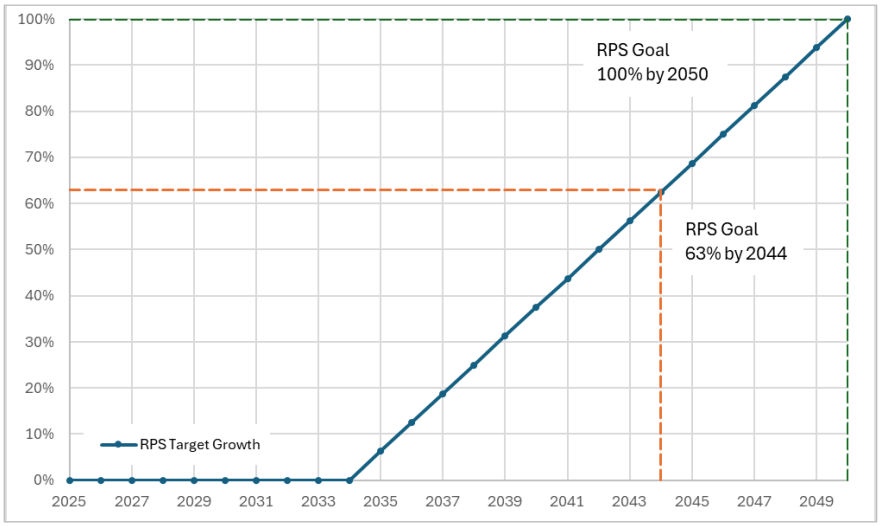
7.3.6 Renewable Portfolio Standard

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[149] 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

[149] 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 2019 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[150]:

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[151]

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

[150] Puerto Rico Energy Bureau. (2020). Proposed Definition for the Term "Highly Efficient Fossil Generation". (CEPR-MI-2016-0001, November 6)
[151] 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 dates 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.

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 number 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 agricultural 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 entrepreneurial 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. [152]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
5. Optimistic Load Growth and Costs	5. Storage Costs
6. Less Ag. Land Use	6. New Natural Gas Units Allowed
7. Compliance with Act 17 EE	7. Fossil Fuel Costs

[152] 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

Scenario Name	Characteristics
8. Marine Cable	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[153] and other changes within 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.

[153] 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 comply with the requirements in Regulation 9021. LUMA's methodology serves to:

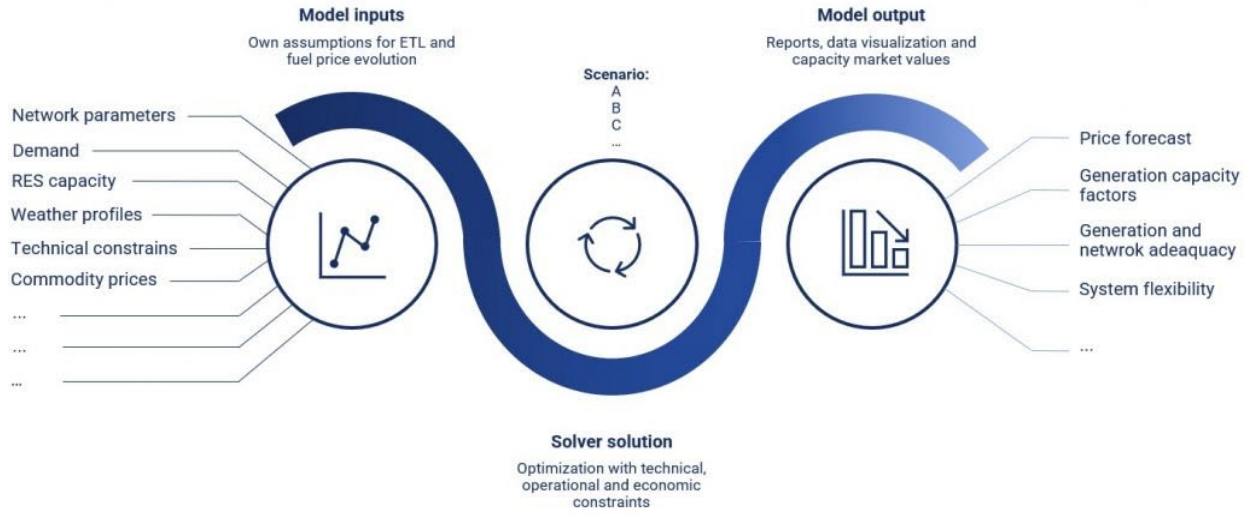
- Incorporate the input and feedback from a broad group of stakeholders through structured workshops held during multiple stages of the development process
- Optimize PVRR over the 2025 to 2044 Planning Period. LUMA employed a resource planning model developed to formulate least-cost resource plans that 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

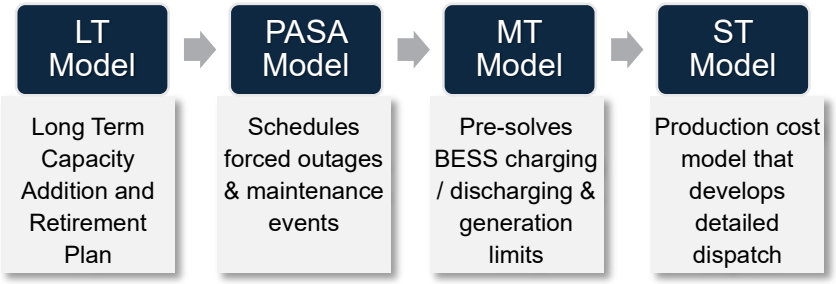


PLEXOS® works by dividing modeling into phases. Each phase performs a “handoff” and passes its results to the next phase. A brief description of the four phases of the PLEXOS® model is provided below:

- **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

For the development of the 2025 IRP modeling, LUMA considered a series of assumptions some of which were fixed decisions that applied to all the Scenarios. The fixed decisions included the addition of generation resource projects that have received government approval or are currently in advanced stages of development and mandated retirements of certain existing generation units. In addition, Puerto Rico must comply with an established list of additional planning criteria applied to all Scenarios. LUMA collectively refers to this work in the 2025 IRP as “Fixed Decisions.” The decisions are fixed in that the IRP takes these as given.

Fixed Capacity Additions and Retirements

The following fixed decisions were incorporated into the analysis as of May 2025 to ensure consistency and alignment with Act 1-2025, and existing and approved projects.

Fixed additions:

- Tranche 1: 739 MW Utility-Scale Solar (“UPV”) and 535 MW UBESS in 2025 and 2026
- Tranche 2: 66 MW UPV and 60 MW of UBESS in 2026
- Tranche 4: 50 MW UBESS in 2027
- Non-Tranche UPV: 200 MW from three projects, Ciro One, Phase 1, Ciro One Phase 2 and the Xzerta project with additions from 2025 to 2027
- Energiza Combined Cycle: 478 MW LNG fueled combined cycle generator in 2028
- Emergency Generators: 200 MW in 2025 and 600 MW in 2026 of natural gas generation
- Accelerated Storage Addition Program (“ASAP”): 196 MW of UBESS projects from the ASAP, Phase I program, and 425 MW of UBESS from the ASAP, Phase II projects, all in 2026
- Genera Peaking Units: 244 MW LNG Reciprocating Internal Combustion Engines (“LNG RICE”) and Combustion Turbines (“CT”) in 2027

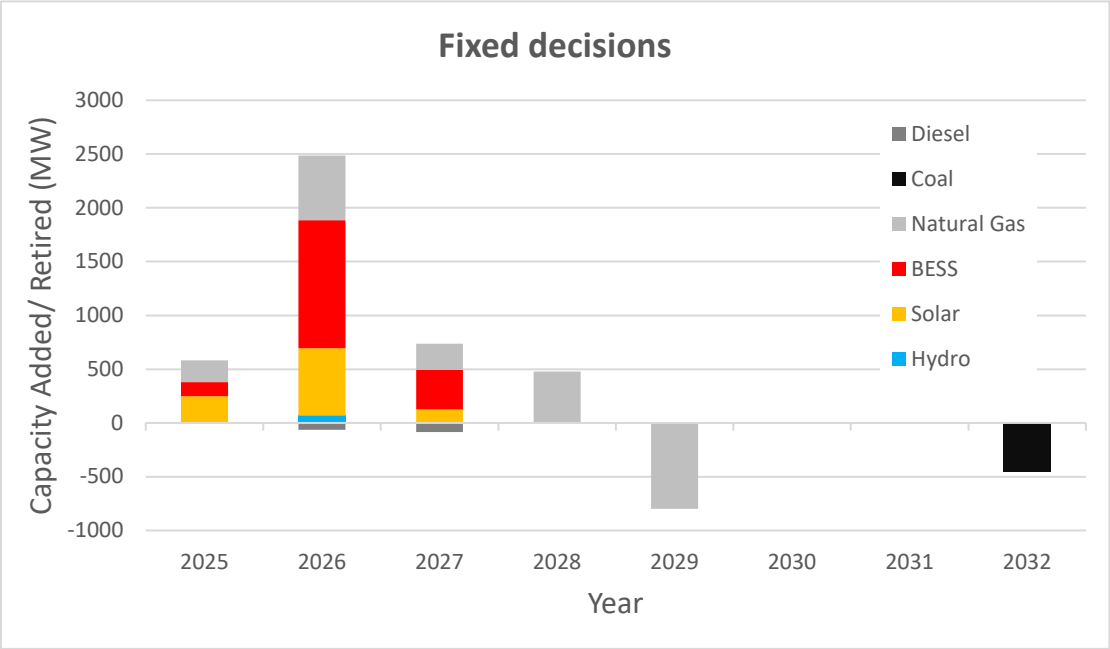
- Genera Batteries: 430 MW UBESS in 2026
- PREPA Hydroelectric 38 MW of additional capacity added in 2026 through refurbishment of existing units

Fixed retirements:

- Gas Turbine ("GT") Peaking Units: 147 MW Diesel in 2027
- AES 1 and AES 2: 454 MW Coal in 2032
- Emergency Generators: 800 MW fueled with natural gas in 2029 after the Energiza Combined Cycle COD
- Aguirre 1 & Aguirre 2 are assumed to be out of serviced during the full 2025 IRP Study period.

Figure 68 below shows the fixed capacity additions and retirements incorporated into the model of Scenarios 1 to 10.

Figure 68: Fixed Decisions Capacity Additions and Retirements



8.2.3 Additional Planning Criteria

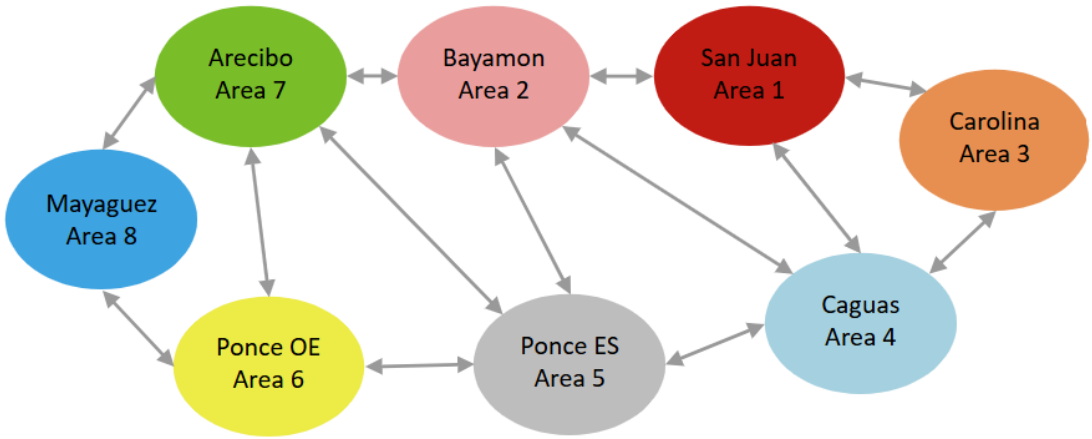
LUMA has established a list of planning criteria and outputs for multiple categories in addition to the Fixed Decisions. These were created with the input of stakeholders who participated in the SETPR meetings held around the Island. These were also reviewed with the Energy Bureau and the Energy Bureau's Consultant and updated to reflect changes in 2025. For example, the criteria related to RPS were 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 begin at zero in 2035 and then increases by 6.7% per year[154] 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. [155]
- 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 bidirectional transmission links, shown in Figure 69, that represent the collective T&D system connections and their 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, was 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

[154] 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.

[155] 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[156];
- 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%

[156] 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.

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[157]
  - 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

[157] 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.

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)
2025	300	0
2026	300	0
2027	300	0
2028	300	0
2029	300	0
2030	270	30
2031	240	60

Year	Reserves for Regulation Up (MW)	Reserves for Regulation Down (MW)
2032	210	90
2033	180	120
2034 - 2044	150	150

- 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)
1	San Juan	Bayamon	818*	773*
2	Bayamon	Arecibo	204	214
3	Arecibo	Mayaguez	249	206
4	Mayaguez	Ponce OE	336	229
5	Ponce OE	Ponce ES	150	1020*
6	Ponce ES	Caguas	233*	332*
7	Caguas	Carolina	120	132
8	Carolina	San Juan	221*	167*
9	Caguas	San Juan	321*	224*
10	Caguas	Bayamon	322*	225*
11	Ponce ES	Bayamon	232	1153*
12	Ponce ES	Arecibo	205	275
13	Ponce OE	Arecibo	115	287

* DC Transfer Limit

LUMA has modeled the Puerto Rico grid in PSS®e 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 PSS®e 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, are 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.

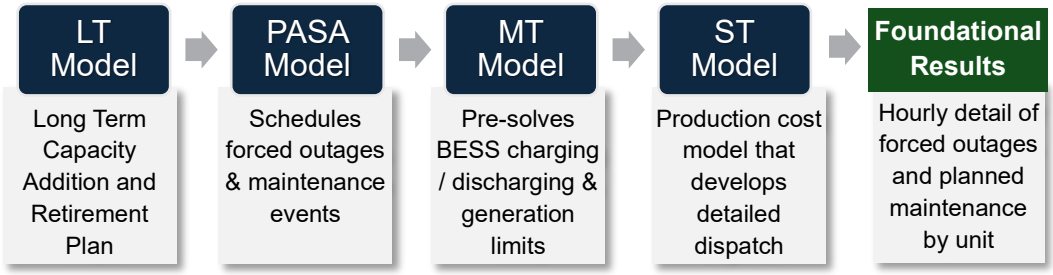
The planned and forced outages in the ST model are based on analysis performed in the PASA module. The PASA module schedules a specific time to perform planned maintenance, considering the planned maintenance needs of other units. The PASA module then uses a Stochastic simulation to schedule a repeatable 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%[158] 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 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 were 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®



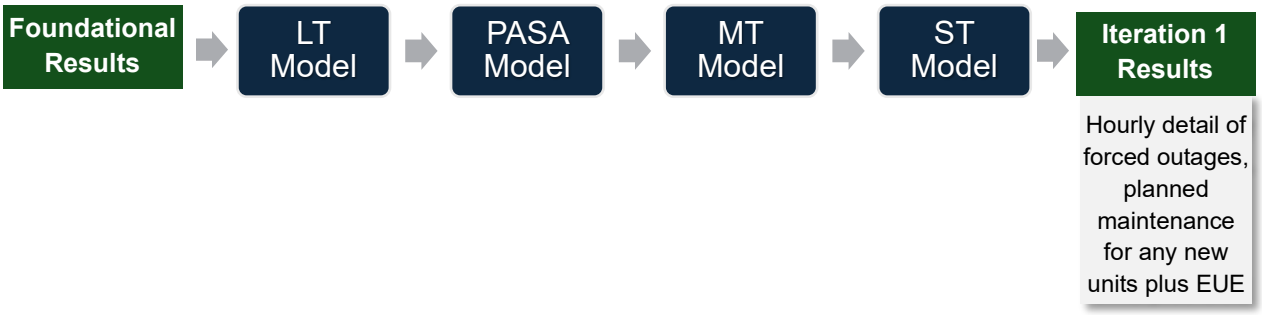
8.2.6 Loss of Load Expectation Modeling in PLEXOS®

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.

[158] 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

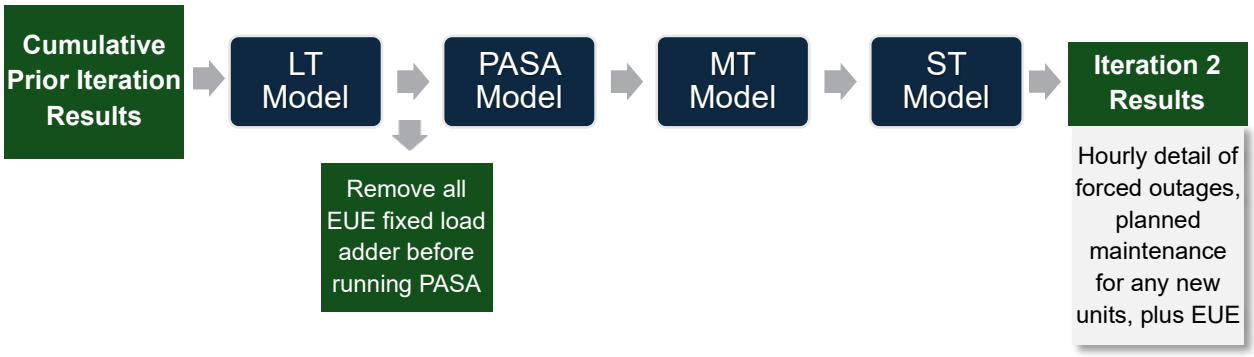
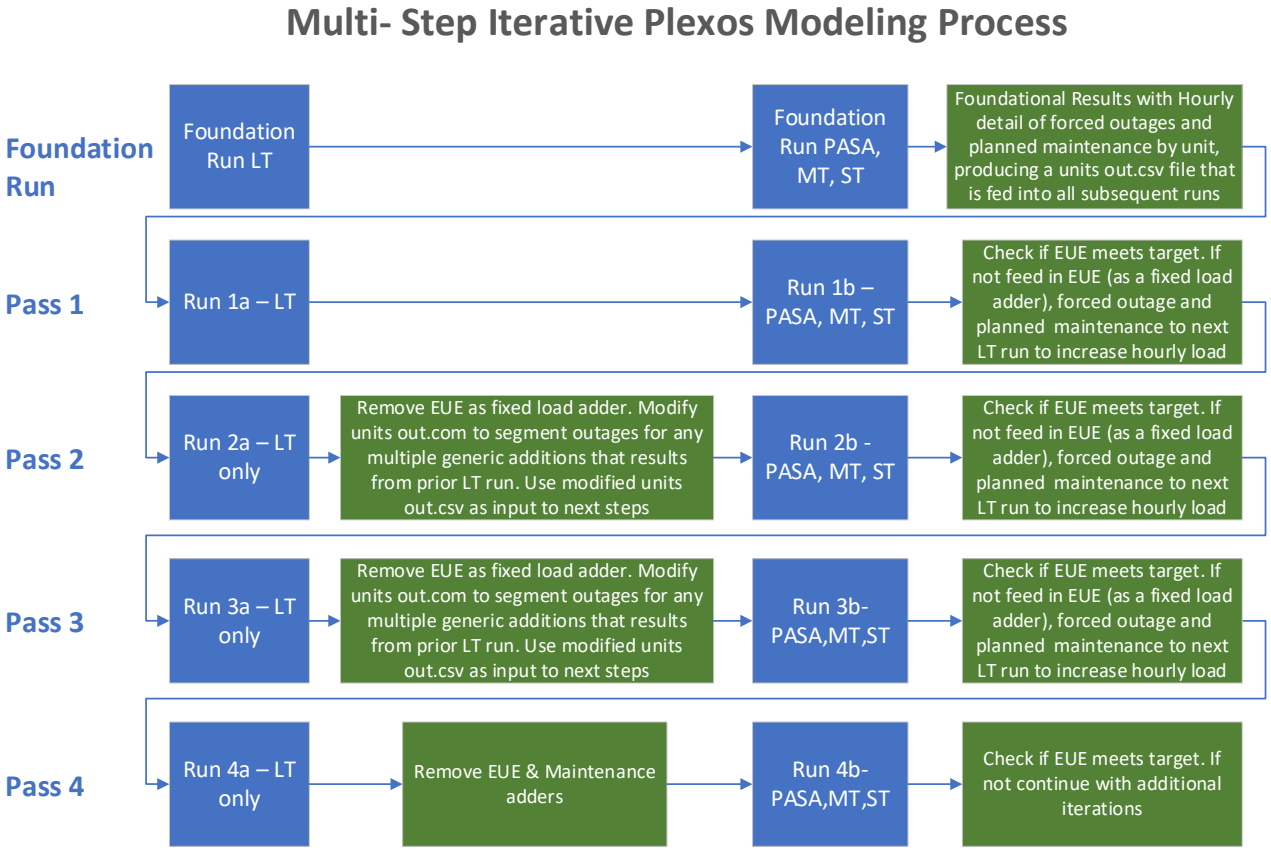


Figure 73 provides a more detailed illustration of the process used for the iterative runs.

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[159]	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

[159] 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.

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 describes 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, 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.

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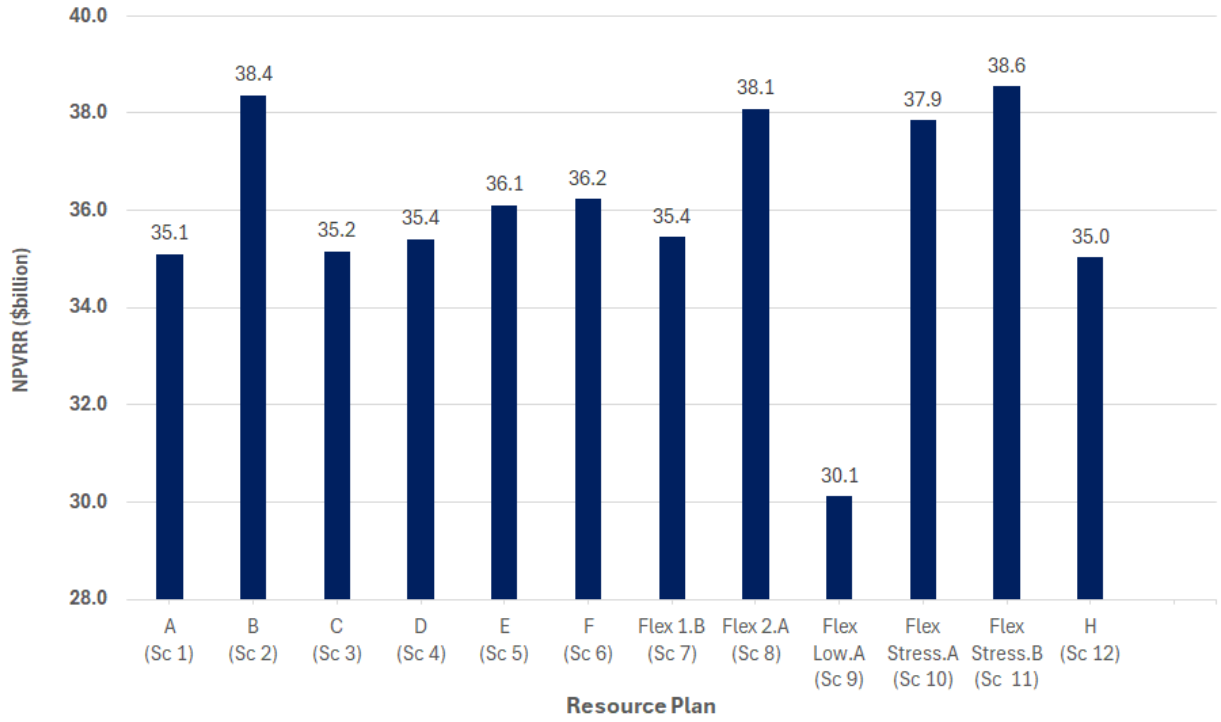
Table 90: Results of Multi-Step EUE Reduction Process for the development of Resource Plan A

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.

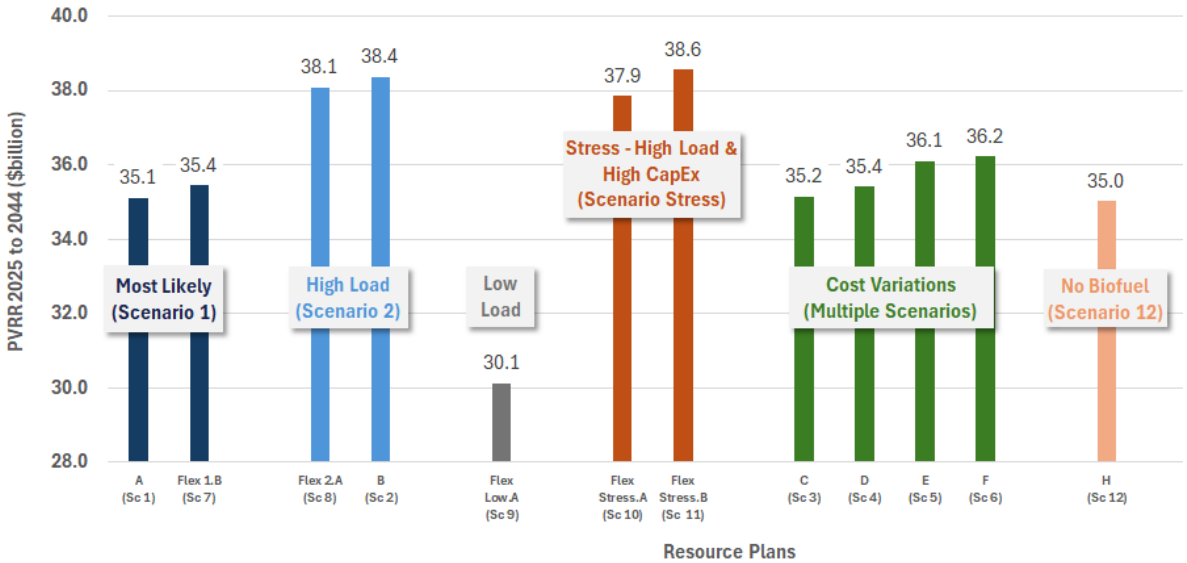
Each of the Resource Plans resulting from the Primary Scenarios included transmission system upgrades to increase the transfer capacity between TPAs. In addition to providing candidate expansion generation resources with their costs and technical characteristics, LUMA provided candidate transmission 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)

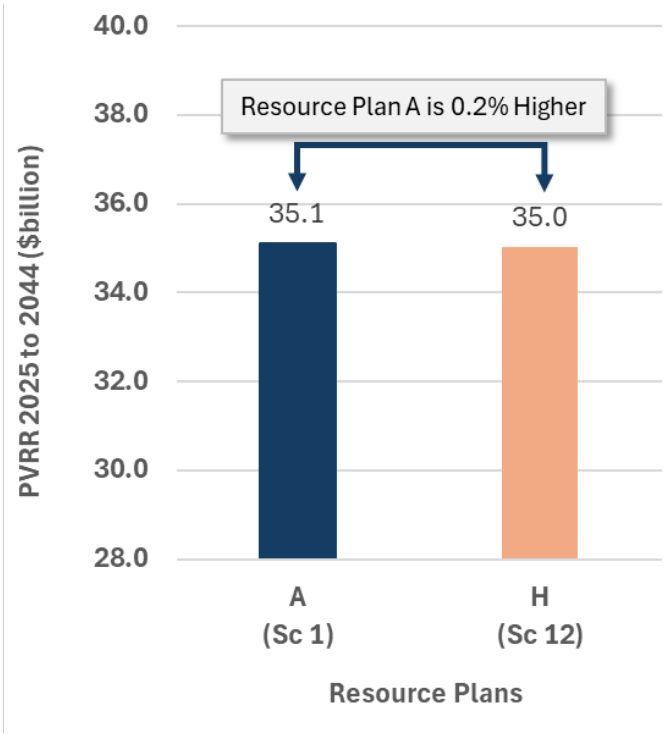
Figure 75: Reordered 20-Year PVRR for Resource Plans Resulting from the 12 Primary Scenarios



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[160] 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

[160] 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[161]	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%)**

[161] 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)[162]	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

[162] 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)[163]	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.

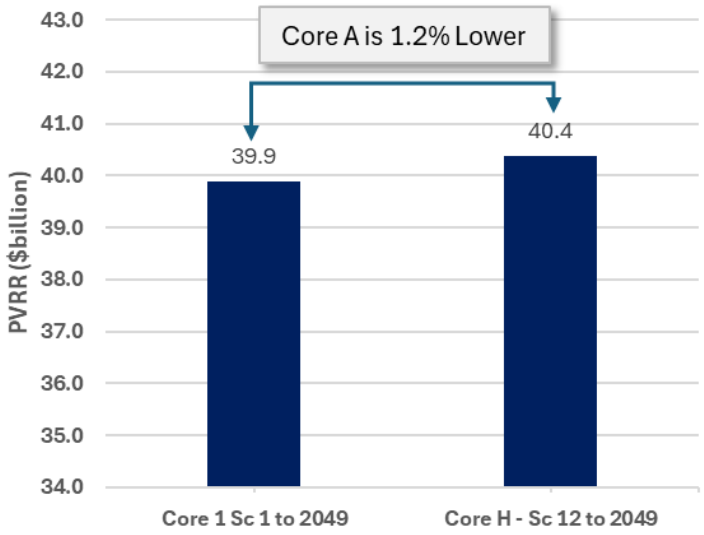
8.2.18 Extended Analysis Until 2050 for Biodiesel vs No Biodiesel Resource Plans (A vs H)

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

[163] 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 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

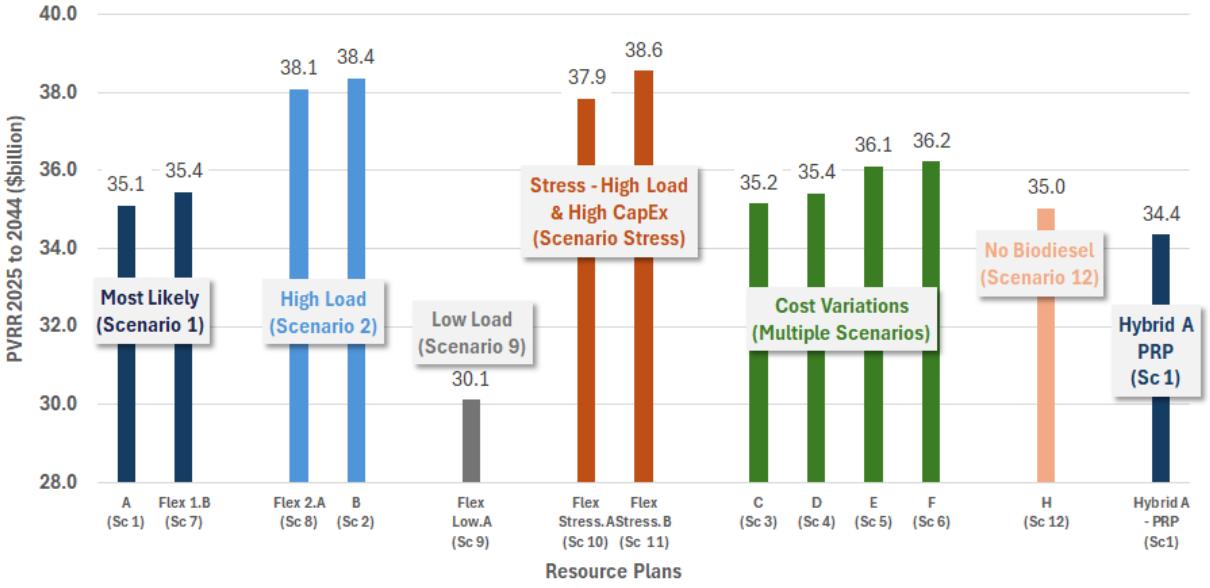
Resource Plan	Scenario	Load	Costs	Biodiesel Available	PVRR WACC 8% ($B)	PVRR WACC 7% ($B)	PVRR WACC 6% ($B)	PVRR WACC 5% ($B)	PVRR WACC 4% ($B)
Hybrid A - PRP	Scenario 1	Base	Base	Yes	34.4	37.6	41.3	45.6	50.5
Core A	Scenario 1	Base	Base	Yes	35.1	38.5	42.3	46.7	51.7
Core B	Scenario 7	Base	Base	Yes	35.4	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 Core Resource Plans was 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. [164]

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.

[164] Id.

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Table 98: Resource Plan Indicators Results- Scorecard Part 1[165]

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)			% 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 (%)
						5-year 2025 to 2029	10- year 2025 to 2034	20-year 2025 to 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

[165] 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.

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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
CHP	47	22	13	13	5																**100**
DR				1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	**661**
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	**1,109**
New Distributed Storage			3	5	5	6	2	3	3	3	3	4	4	5	6	6	3	4	4	4	**71**
Hydro Gen		38																			**38**
Emergency Generator	200	600																			**800**
Thermal Gen				478																	**478**
New Genera Gas Gen Biodiesel Conversion			244																		**244**
New Gas Generation							105		373												**478**
New Gas Gen Biodiesel													452			373					**825**
New Genera Gas Gen Biodiesel Conversion											36				172					36	**244**
Legacy Unit Biodiesel Conversions											75										**75**
Non-Tranche Solar	90	50	60																		**200**
Tranche 1 Solar	160	579																			**739**
Tranche 2 Solar			66																		**66**

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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	Total
ASAP Phase 1		190																			**190**
ASAP Phase 2							418						7								**425**
New Genera BESS Units	131	141	158																		**430**
Regulation Only BESS[166]				100																	**100**
Tranche 1 BESS		435	100																		**535**
Tranche 2 BESS			60																		**60**
Tranche 4 BESS			50																		**50**
Total[167]	**774**	**2,099**	**770**	**617**	**47**	**57**	**595**	**74**	**441**	**62**	**164**	**60**	**531**	**96**	**294**	**507**	**158**	**184**	**194**	**196**	**7,918**

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
Land Fill Gas Gen																	2	2			4
Emergency Generator					800																800
AES_1									227												227
AES_2									227												227
AGUIRRE 1 CC												165									165
AGUIRRE 2 CC											100										100
COSTA SUR 5															380						380
COSTA SUR 6														360							360

[166] Capacity from regulation only BESS was not used for generation purposes.
[167] Totals double count a 373 MW CC gas unit that is added in 2033 and then converted to biodiesel in 2040, and 244 MW of new gas Genera units that are added in 2027 and converted to biodiesel in 2035, 2039 and 2044. The total also includes 75 MW of conversion of currently existing legacy units from gas to biodiesel in 2035.

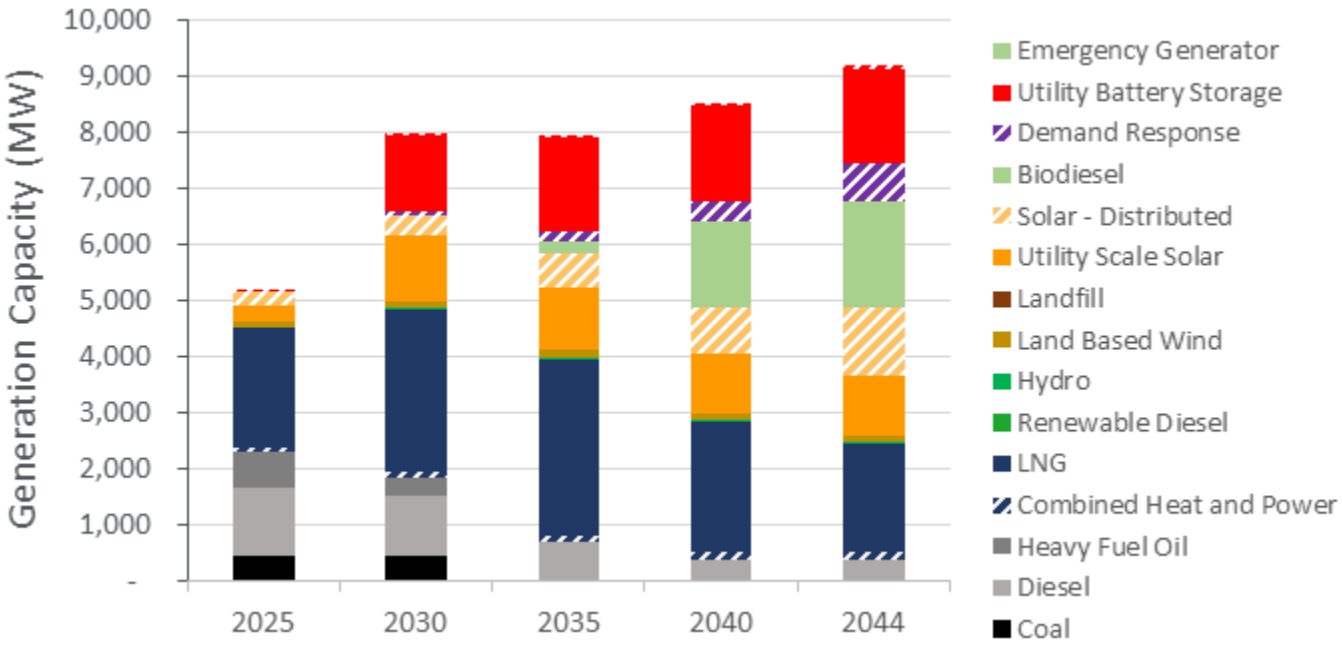
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Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
PALO SECO 3								180													180
PALO SECO 4						200															200
SAN JUAN 7						100															100
SAN JUAN 9							100														100
Peaker Gen		63	84																		147
Solar								2	20			30	55								107
Total[168]	**0**	63	84	0	800	300	100	182	474	0	100	195	55	360	380	0	2	2	0	0	3097

[168] 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.

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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.

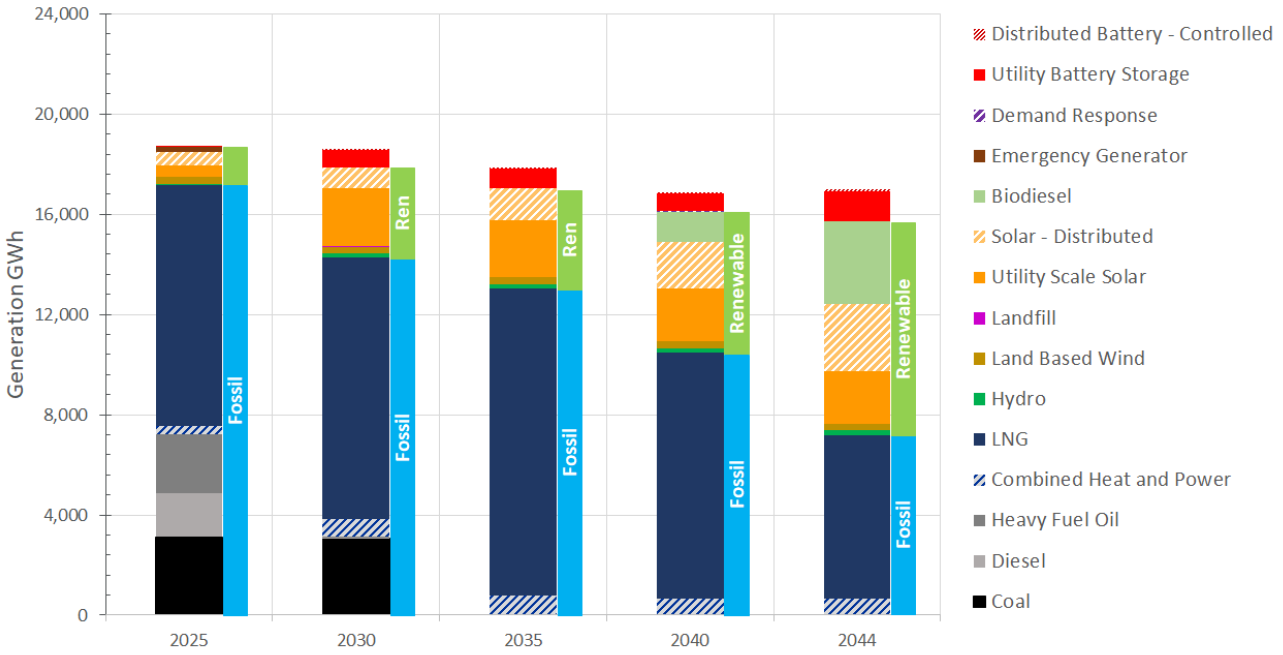
Table 102: Preferred Resource Plan Energy Production by Fuel or Resource (GWh)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Demand Response				0	1	2	3	4	2	6	6	7	8	9	11	14	17	21	25	**25**
Distributed Battery - Controlled			2	3	6	8	5	6	7	8	9	12	13	15	17	16	17	27	41	**54**
Coal	3115	3387	3144	3106	3138	3061	3056	3107												**0**
Diesel	1763	86	23	1	19	27	24	11	17	9	9	15	10	17	5	6	9	8	7	**8**
Heavy Fuel Oil	2324	524	204	7	80	40	10													**0**
LNG - EcoEléctrica	5178	3935	3894	3999	4151	4211	4281	4230	4202	4005	4023	4168	4077	4101	3943	3975	3890	3776	3402	**2842**
LNG - SJ	3852	3838	3377	5703	5773	5741	5640	5341	8250	8258	8040	7700	7648	7317	6857	5758	4945	4214	3825	**3680**
Hydro	24	67	149	149	149	177	177	178	178	177	177	178	177	177	177	178	178	177	177	**178**
Utility Scale Solar	398	740	854	946	945	944	944	943	898	900	899	844	724	726	724	728	725	725	726	**727**
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	**269**
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	**0**
LNG - Trucked	604	250	724	87	592	455	330	285	234	213	215	162	158	148	17	76	68	33	28	**4**
Biodiesel											6	1	5	48	530	1220	1903	2431	2904	**3305**
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1261	1263	1262	1267	1263	1261	1262	**1264**
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	**107**
Combined Heat and Power	346	426	511	667	751	729	698	742	803	788	757	727	699	677	661	653	654	654	652	**653**
Solar - Distributed	546	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1682	1842	2011	2207	2424	**2666**
Emergency Generator	215	3108	3072	1046																**0**
Utility Battery Storage - 4hr	5	100	161	162	195	190	151	153	166	159	160	177	170	184	181	155	153	187	231	**256**
Utility Battery - Tranche 1		123	271	237	307	304	236	238	258	251	252	273	265	285	286	241	244	292	379	**417**

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Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Utility Battery - Tranche 2			18	35	39	38	27	29	31	30	31	32	31	35	34	27	28	36	48	**53**
Utility Battery - Tranche 4			22	40	45	41	29	27	31	31	30	31	31	33	34	28	28	34	48	**55**
ASAP Utility Battery Phase 1		65	106	89	108	103	262	262	280	273	287	300	286	310	310	276	273	320	393	**423**
Total Generation	**18697**	**18531**	**18817**	**18670**	**18738**	**18571**	**18448**	**18224**	**18112**	**17955**	**17829**	**17642**	**17402**	**17292**	**17127**	**16858**	**16792**	**16781**	**16949**	**16986**

Figure 80: Preferred Resource Plan Energy Generation by Resource (GWh)



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
Coal																				
Heavy Fuel Oil	3491	617	203	10	113	39	10	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Diesel	1708	83	21	1	17	25	22	10	16	8	8	14	10	16	4	5	8	7	7	**7**
LNG	4766	5852	5700	4914	4686	4649	4567	4372	5457	5363	5270	5146	5075	4930	4566	4313	3896	3476	3118	**2770**
Biodiesel - B100	0	0	0	0	0	0	0	0	0	0	6	1	5	43	501	735	1133	1436	1705	**2005**
Grand Total																				

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
Coal																				
Heavy Fuel Oil	42033	7434	2448	117	1358	468	123	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	20884	1014	262	8	211	311	271	123	198	101	114	176	126	259	726	964	1216	1147	923	580
LNG	81409	99956	97348	83922	80041	79397	78002	74669	93198	91593	90002	87898	86672	84207	77985	73663	66542	59378	53261	47308
Biodiesel (portion of the blend)	0	0	0	0	0	0	0	0	0	0	62	14	47	455	5469	8115	12797	16575	20088	24117

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 considered the uncertainty of success to be 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. LUMA considered that the number of required daily LNG fuel truck deliveries to be 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[169] 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 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

[169] 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%.

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, 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 2028 addition of the four 25 MW, 4-hour batteries (referred to as Regulation Only BESS, or 4x25 BESS) is planned for only system regulation under regular operations. 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

Table 107 below summarizes the energy resource additions for 2025 to 2030.

Table 107: Preferred Resource Plan Energy Resource Additions for 2025 to 2030 (MW)

Energy Resource	2025	2026	2027	2028	2029	2030	Grand Total
Customer Distributed Generation							
CHP	47	22	13	13	5		100
DPV	146	44	16	20	23	29	278
Fixed Decision Generation							
PREPA HydroCo Repairs		38					38
Emergency Generators	200	600					800
Energiza Gas CC				478			478
New Genera Units			244				244
Non-Tranche Solar	90	50	60				200
Tranche 1 Solar	160	579					739
Tranche 2 Solar			66				66
Fixed Decision Batteries							
ASAP Phase 1		190					190
New Genera Units	131	141	158				430
Regulation 4x25 BESS				100			100
Tranche 1 BESS		435	100				535
Tranche 2 BESS			60				60
Tranche 4 BESS			50				50
PRP Recommended Customer Programs							
Demand Response				1	14	22	37
Controlled DBESS			3	5	5	6	19
Grand Total	**774**	**2,099**	**770**	**617**	**47**	**57**	**4,364**

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

Table 108: 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, negotiation of interconnection agreements, and implementation of any required transmission network upgrades.
Fixed Decision Batteries	1,365	31%	Process and assess 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 PSS®e analysis of the transmission impact of the PRP. The results of the PSS®e 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. Table 109 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 Table108. The retirement of the seven 21 MW GT units is contingent on the planned addition of the New Genera Peaking Units identified in Table 108. 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.

Table 109: Preferred Resource Plan Energy Resource Retirements for 2025 to 2030 (MW)

Energy Resource	2025	2026	2027	2028	2029	2030
Emergency Generator					800	
PALO SECO 4						200
SAN JUAN 7						100
Thermal Gen						
GT01-Palo Seco (Diesel)			21			
GT02-Palo Seco (Diesel)			21			
GT20-Jobos (Diesel)		21				
GT21-Daguao (Diesel)		21				
GT22-Daguao (Diesel)		21				
GT03-Palo Seco (Diesel)			21			
GT12-Yabucoa (Diesel)			21			
Grand Total		**63**	**84**	**0**	**800**	**300**

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

Table 110 provides a summary listing of the recommended action plan.

Table 110: 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

Appendixes

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Appendix 1: Transmission & Distribution Plan

NEPR-AP-2023-0004

1.0 Executive Summary

In this appendix LUMA provides a comprehensive Transmission and Distribution (T&D) Plan filing consistent with Regulation 9021 requirements. Included in this report are discussions and analyses of the existing state of the Puerto Rico T&D system relative to industry codes and standards. Specific focus is provided on system stabilization, reliability performance, resilience, and infrastructure needs to support decarbonization.

Not included in this T&D report are:

- Discussion and assessment of the T&D infrastructure required to support the Preferred Resource Plan which are anticipated to be delivered later.
- Discussion and analysis of ongoing System Stabilization Plan activities that include restoration of out-of-service substation transformers, restoration of out-of-service transmission line facilities, and other related activities being managed as part of PREB's ongoing System Stabilization Plan initiative.
- Discussion and analysis of near-term system investments supported by a recent (October 2025) Department of Energy Grant award which supports portions of the System Stabilization Plan and provides additional investments to support vegetation management, distribution automation and system improvements, advanced meter-infrastructure, and accelerate much needed investment in the Puerto Rico grid.

Section 2 of the report highlights the state of the system and progress since 2021. Although LUMA inherited a significantly deteriorated and unmaintained system that is experiencing accelerated degradation that shows up in reliability performance, the focused investments made since 2021 are highlighted. These include storm hardening through pole and structure replacement of over 32,400 the most vulnerable assets to better withstand hurricanes force winds, deployment of over 10,500 grid automation devices avoiding over 460 million customer outage minutes, cleared over 6,491 miles of vegetation from power lines, replaced over 184,000 streetlights to improve community safety, enabled over 175,000 rooftop solar systems with a record 153,000 battery energy storage systems accounting for over 1,282MW of solar energy capacity and 850MW/2,600MWh of battery energy storage capacity/energy.

Customers, stakeholders and regulators may track progress at: https://progresodelumapr.com/progreso-para-puerto-rico/

Section 3 discusses investment planning and prioritization strategies, methodologies, and processes. LUMA's investment strategy is driven by strategic pillars of system stabilization and asset replacements to improve public and worker safety and equipment and community support, reliability and resilience improvements to address the worst reliability impacts first and harden the grid against resilience threats, and supporting regulatory and community objectives of driving deep decarbonization and supporting distributed energy integration. Projects are prioritized using a multi-criteria model whose inputs include asset condition, system risk, historical reliability and stakeholder inputs. Anticipated funding sources include FEMA, DOE grants and customer-funded capital, and investments must optimize across strategic pillars to provide maximum value for customers.

Section 4 provides in-depth discussion and analysis of the Puerto Rico transmission network, including the 424 miles of 230kV network, 711 miles of 115kV lines and 1563 miles of 38kV sub-transmission lines. Key

findings of Transmission Planning assessments identify root causes of chronic poor reliability performance, including 26 critical contingencies that result in thermal overload of over 30 facilities that can result in cascading line trips affecting entire regions, or risks island-wide stability. And another 17 group of critical contingencies lead to severe voltage issues affecting entire regions. Together, these thermal and voltage violations demonstrate that the Puerto Rico grid does not adhere to basic electric utility criteria of N-1 reliability (where loss or failure of one element should not result in impact to customer load). Note that this result is partly due to existing out-of-service facilities, many of which are being restored under System Stabilization Plan and/or DOE grant activities described above, but many are underlying planning and design issues where redundancy and equipment ratings do not allow for industry standard reliability. Mitigation strategies and proposed projects have been identified, but do not yet have identified funding sources.

Section 5 provides in-depth discussion and analysis of the Puerto Rico distribution system. Supplied by 342 distribution substation transformers and constituting 1127 individual circuits across five voltage levels (13.2, 8.3, 7.2, 4.8 and 4.16kV). Over 50% of transformers have been in-service for 40 years or more. Additionally, over 25 of these are currently over 90% of their manufacturers specified maximum rating with 41 forecasted to exceed their ratings in the next 3 years based on the rate of requests for new-load connections. The aging infrastructure, with a lack of redundancy and gaps in maintenance history, puts increased pressure on maintenance requirements and investment needs as these devices need to be replaced on an aggressive schedule to control reliability performance. Finally, 87 of Puerto Rico's 299 substation sites are in flood-prone areas which will also require increased attention as a resilience risk in future severe weather events. Distribution circuits require investments in hardening main-lines, reconductor and rebuilds to improve the 309 circuits identified with voltage regulation issues due to loads, and distribution automation technologies to build redundancy to improve reliability performance.

Section 6 highlights the facilities, configuration and subsystems that constitute the Puerto Rico electric distribution system; these include substation transformers, distribution circuits, system protection, and voltage and reactive power control systems. Each of these subsystems is discussed in detail with regional and voltage-level specific considerations. The portfolio of programs that impact distribution substations (substation rebuilds and substation component replacement) is discussed with the various funding mechanisms (FEMA, DOE, and Non-Federal Capital) funds all required to achieve system stabilization, asset improvements, reliability improvements and resilience hardening strategic objectives. The portfolio of programs that impact distribution feeders and associated sub-systems includes feeder rebuilds targeting worst performing circuits, pole and conductor repairs targeting safety and asset condition highest priorities, and distribution automation and reliability improvement programs. Again, the blended funding sources of FEMA, DOE, and Non-Federal Capital are all required to achieve strategic objectives that benefit all of Puerto Rico's electric utility customers.

Section 7 details Puerto Rico's distributed renewable energy portfolio which is one of the highest in the U.S. with 49% average circuit penetration (installed PV capacity compared to circuit peak demand). LUMA supports the continued deployment of customer distributed renewable energy technologies to drive customer need for reliability and resilience, but strongly advocates for sensible policy and regulatory updates to ensure that non-participating customers, the grid infrastructure and feeder health, and utility work and public safety are also priorities. For example, the existing deployments already can implement Smart Inverter Settings, specifically Volt-VAR that shows significant potential to stem the DER related high voltage issues being experienced today. Additionally, significant investment will be required to keep distribution infrastructure healthy with the current pace of solar PV and battery installations.

Section 8 provides a summary of the improvements made to system stability's simulation tools and models, which are required to improve performance as customer-connected DER drive conventional plants closer to their minimum load levels, and as fast dynamics play a bigger role in a grid that is becoming more decentralized with both utility-scale and customer resources.

The analysis and report conclude that significant performance gaps exist in transmission, substation and distribution, and that basic customer needs and expectations of high quality and reliability from their electricity supply must be met. This requires significant additional investment to remedy the gaps that exist today, and to harden and optimize resources, infrastructure and customer technologies to meet customer needs.

2.0 Introduction and Background

This Transmission and Distribution (T&D) Plan Report is provided as an Appendix to the Integrated Resource Plan (IRP) filing consistent with regulations established in Regulation 9021 Section 2.03(J). The report follows the flow of the regulation, and provides existing facilities descriptions of the Transmission infrastructure, of the Distribution Infrastructure, then provides insights on the studies, assessments, and plans that are in place to improve the Puerto Rico grid. Do note, however, that the preferred resource portfolio assessment is expected to be delivered on a separate timeline and is not included in this report.

Section 2 discusses investment planning and prioritization strategies, methodologies, and processes. LUMA's investment strategy is driven by strategic pillars of system stabilization and asset replacements to improve public and worker safety and equipment and community support, reliability and resilience improvements to address the worst reliability impacts first and harden the grid against resilience threats, and supporting regulatory and community objectives of driving deep decarbonization and supporting distributed energy integration. Projects are prioritized using a multi-criteria model whose inputs include asset condition, system risk, historical reliability and stakeholder inputs. Anticipated funding sources include FEMA, DOE grants and customer-funded capital, and investments must optimize across strategic pillars to provide maximum value for customers.

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Section 7 provides summaries of improvements made to System Stability simulation tools and models, which are required to improve performance as customer-connected DER drive conventional plants closer to their minimum load levels, and as fast dynamics play a bigger role in a grid that is becoming more decentralized with both utility scale and customer resources.

2.1 System Conditions Prior to LUMA's Establishment

When LUMA began the operation of the electric system in July 2021, the grid impacts of decades of under-investment and neglect were evident. In fact, prior to LUMA's assumption of the operation, Puerto Rico's electric system was well below the minimally acceptable utility reliability standards, considerably worse than any peer utility, as defined by benchmarking conducted in accordance with IEEE 1366-2022 – IEEE Guide for Electric Power Distribution Reliability Indices. To understand whether the existing infrastructure at the time met utility standards for safe and reliable operation, LUMA conducted a system-wide gap assessment which resulted in the identification of over 1,000 gaps which determined that most system assets were past their useful design life, and/or in poor health – again, due to decades of neglect and mismanagement under the previous operator.

These gaps were identified and are related to the unmanaged and unmaintained physical assets on the grid. These gaps correspond directly to the below-industry-standard reliability performance of the grid. Remedying this situation requires significant improvements, resources, and capital. As recognized in the Transmission and Distribution Operation and Management Agreement (T&D OMA, Section 4.1(d)), LUMA began operating an electrical system which could not meet Prudent Utility Practice and could not meet the T&D OMA Contract Standards. LUMA developed the System Remediation Plan (SRP) to provide an appropriate transition from the initial state of the system and utility processes at commencement, to one where conditions are met for prudent utility practice and compliance with T&D OMA Contract Standards.

Since then, LUMA has been implementing multiple programs that focus on improvements to the T&D System and have made tremendous progress across all facets of Puerto Rico's electric grid. Examples of the significant progress made over the last four years include:

- **Strengthened the energy system against storms and hurricanes**: by replacing more than 32,400 utility poles with new stronger poles able to better withstand hurricane force winds;
- **Reduced the size and the impact of outages:** by installing over 10,500 grid automation devices, which have served to avoid over 460 million service interruption minutes for Puerto Rico electricity customers;
- **Addressed the largest cause of outages:** by clearing vegetation from over 6,491 miles of powerlines and electric infrastructure through June of 2025;
- **Improved community safety and energy efficiency:** by replacing over 184,00 streetlights as part of LUMA's Community Streetlight Initiative;
- **Enabled the adoption of DPV:** by connecting over 175,000 customers to rooftop solar, representing over 1,282 MW of clean, renewable energy for Puerto Rico, along with a recorded 153,000 Battery Energy Storage Systems representing 850MW and 2,600MWh of energy storage capacity, and;
- **Improved reliability during generation shortfalls:** by launching the Customer Battery Energy Sharing (CBES) initiative to aggregate customer home batteries to provide system support during known generation shortfall events. By October 2025, CBES had over 80,000 participants reliably providing up to 65MW of response over 4-hour events during summer 2025.

2.2 Reliability, Resiliency and Enabling Growth of Distributed and Utility-Scale Renewables

LUMA's T&D planning practices anticipate future needs, mitigate risks, and optimize grid infrastructure to improve reliability every day, improve system resilience to extreme weather, and improve utility worker and public safety by mitigating or eliminating unsafe conditions. T&D planning focus is to create a reliable, efficient, and flexible grid capable of meeting both present and future energy needs. System performance improvements must address capacity constraints, reliability, renewable energy integration, smart grid technologies, resilience, cost optimization, regulatory compliance, and extreme weather hardening. Reliability, resiliency, and the enabling of growth for distributed and utility-scale renewables are critical aspects of modern T&D planning. As the energy landscape shifts toward renewable energy sources, these factors become central to ensuring that the electrical grid can meet the evolving demands of both consumers and the environment.

- **Reliability:** A key focus is ensuring that the transmission and distribution network is reliable. Simply defined, a reliable system is one where customers experience very few interruptions in electricity service. Improving reliability requires designing systems that can handle faults, eliminate grid disturbances, and minimize disruptions. Reliability is improved by providing alternate routes for power delivery in case of equipment failure or distribution line, transmission line, or substation asset outages, thereby minimizing downtime experienced by the customer and improving the overall reliability of the grid.

- **Resiliency:** Resiliency refers to the grid's ability to limit the impacts and customer interruptions from extreme weather like storms, but also to recover quickly when these extreme events occur. These events include natural disasters (storms, floods, and wildfires), equipment failures, or cyberattacks. Examples of evolved infrastructure plans include strengthening infrastructure to withstand higher wind speeds, using underground cables to limit wind exposure or wildfire exposure, and/or developing emergency response plans to improve damage prediction, damage assessment and accelerate system restoration.

- **Enabling Growth of Distributed and Utility-Scale Renewables:** Customers are sending a clear message with the rapid pace and scale of rooftop solar PV and battery energy storage adoption. With the increasing adoption of renewable energy sources (such as solar, wind, and battery energy storage), grid modernization enables these resources to provide maximum benefit at an affordable cost. Grid planning must focus on integrating these weather-dependent, variable energy resources into the grid. This requires upgrades to infrastructure to accommodate the intermittent generation and two-way power flows on the distribution network, upgrades to back-office systems and tools to gain real-time visibility into grid performance, and rapidly balance supply and demand which become increasingly variable with system load.

3.0 Methodology for Identifying and Prioritizing T&D Investments

3.1 Description of System Assessment and Analysis Methodologies

LUMA's System Assessment and Analysis Methodologies for developing Transmission rebuild projects are derived from industry-standard objective criteria (such as North American Electric Reliability Corporation [NERC] Transmission Planning criteria), and the Puerto Rico grid existing performance is evaluated against these objective criteria, and for developing Distribution rebuild projects are derived from LUMA's Distribution Planning Criteria. These assessment and analysis methodologies described below are essential for evaluating the grid performance, reliability performance, and required capacity of the electrical grid for current and future scenarios. Performance gaps such as thermal overloads, voltage violations, or simulated grid instability are identified for the system "as operated", "as planned", and against contingency scenarios where loss of an individual element, or group of elements, should not lead to customer load interruptions. In the event load loss or cascading to more widespread outages is identified, a mitigation solution should be developed. Mitigation solutions for each gap identified, and potential future projects are evaluated against the same criteria to ensure that each potential future solution a.) solves an existing thermal, voltage, or stability violation, and b.) are still relevant for future scenarios and sensitivities analyzed, or the mitigation solution may be modified to ensure projects today serve near-term future grid needs. LUMA implements the T&D planning methodologies listed below:

- **Power Flow Analysis** – evaluates the steady-state operation of the electrical network during normal conditions, identifying voltage profiles, power losses, and the load-carrying capacity of the network. Note that models are built to represent the system as it operates today, as well as future predictive models for how the system will operate. LUMA utilizes PSS®E for this analysis on the transmission system. LUMA utilizes Syneri for this analysis on the distribution system.

- **Contingency Analysis** – identifies the potential impact of various "what-if" scenarios such as loss of a key transmission line or generation unit. Performance violations like thermal overloads, voltage violations, and cascading outages leading to massive blackouts can be identified. LUMA utilizes PSS®E for this analysis.

- **Short Circuit Analysis-** helps in determining the fault levels that could occur during various fault scenarios. Equipment like busbars and circuit breakers must be designed to withstand the modeled fault-current values or upgrades may be required to ensure the equipment is rated to interrupt fault current magnitudes that will be experienced during a fault. LUMA uses both PSS®E and CAPE for this analysis.

- **Reliability Analysis**- helps to assess the risk of failures and plan for contingencies. Alternate configurations, generation dispatch levels, and/or system switching may be required to ensure the system can perform reliably under a given load and generation configuration.

- **Transmission and Distribution Planning (Capacity Expansion)** – together, the analyses described above help to plan a system layout and configuration, where each element has sufficient capacity to

carry its own load, and can accommodate loading from unplanned trips of adjacent elements without the need for interrupting customer loads. both existing and future demand scenarios can be evaluated.

- **Dynamic Stability Analysis** - assesses how the system responds to disturbances on rapid sub-second time-scales. These disturbances can be sudden reductions in load, loss of generation events, or short circuits on the network followed by loss of loads or generation. The system thermal, voltage and frequency response is assessed. LUMA uses PSS®E for this analysis.
- **Optimal Power Flow (OPF)** – helps to optimize the power generation and transmission in a way that minimizes operational costs and improves system efficiency while satisfying operational constraints. LUMA uses PLEXOS for this analysis.
- **Economic Dispatch and Unit Commitment** - ensure that generation units can be turned on, or off, in the most economical manner, while balancing the operational constraints. For example, economic dispatch and unit commitment will identify when generators need to remain online to meet evening load increase, and identify when batteries should charge or discharge for most efficient system operation. LUMA uses PLEXOS for this analysis.
- **Integration of Renewable Energy (Grid Integration Studies)** – helps to evaluate the impact of renewable generation on grid stability, voltage regulation, and load forecasting in the existing T&D system. LUMA uses PSS®E for this analysis.

3.2 Transmission Planning Criteria and Design Standards

The Transmission Planning Criteria document, included as Appendix B outlines the objective criteria against which studies evaluate the performance of the existing and proposed future modifications to generation and the grid. Appendix B includes a table derived from the NERC Transmission Planning Standard that defines a system's reliability measures to ensure no load loss for most contingencies. Simply stated, if an element is lost (a contingency occurs), it should not result in overloads or violations that result in customer outages.

The Transmission Planning Standards document, included as Appendix C outlines equipment specifications and capabilities to meet industry design standards and safety requirements. Both are required to define investment prioritization to remediate the gaps and improve system performance according to applicable laws, regulations, and achieve industry standard performance. This Transmission Planning Standard document defines the minimum capabilities and design requirements for transmission facilities proposed for upgrade or reconstruction.

3.3 Distribution Planning Criteria and Design Standards

The Distribution Planning Criteria document is included as Appendix D and outlines the objective criteria to plan and manage the distribution system. This includes guidance on load levels, acceptable thermal loading levels, reactive power, voltage management, and allowable harmonic distortion levels.

3.4 Investment Prioritization Methodology

The strategic objectives driving LUMA include system stabilization, updating end-of-life assets, reliability improvement, generation and renewable integration, and resilience hardening. Investment priorities are defined after completing thorough assessments that include asset and field condition verification, operational experiences, transmission planning analysis and studies, and studies in support of customer load requests, and studies in support of generation and renewable projects. Investment prioritization then optimizes funding and resource allocation to maximize grid infrastructure value while improving reliability, asset utilization, efficiency, and resilience. Projects are prioritized to address critical asset condition deficiencies and system performance gaps, to improve grid performance and reliability, to facilitate the interconnection of new customer loads and generation resources, and to harden against future severe weather threats.

Inputs to prioritization score models to objectively rank investments and compare estimated project benefits include asset risk assessment, system risk assessment, details from operating history, historical reliability contribution trend, and power flow studies to determine contingency impact. Projects that address safety, stabilize the grid, resolve critical reliability issues, improve system capacity to connect new load, and improve capacity to integrate generation and renewable energy sources will rank higher for investment priority.

Stakeholder engagement is also an essential prioritization input. This includes consultation with communities, regulators, residential, commercial and industrial developers, generation and renewable energy developers, and other government entities that may be impacted by proposed T&D investments.

Once all factors, analyses, and stakeholder inputs are considered, the final investment decisions are made. Projects identified as priorities are ranked, then proposed for funding. Funding allocated based on available resources. Investment prioritization is a continuous process requiring periodic review and update as grid conditions, technology, external factors, and available funding. Investment strategy and project priorities are reassessed and updated each fiscal year to ensure the highest priority projects remain the focus.

3.5 Discussion of LUMA Budgets and Funding Sources

Anticipated project funding sources currently include FEMA, a grant from Department of Energy (DOE), and customer funded Non-Federal Capital. Note that since August 2025, a major modification to process to get prioritized projects to FEMA now requires PREPA prior approval– this impacts timelines and budgets that were anticipated for FEMA project review off all project types. The focus and impacts of concern here impact transmission line, distribution line and substation rebuild projects, and are identified throughout the report. Regarding DOE funding, LUMA anticipates that the grant award will support critical stabilization and restoration activities over approximately 12-18 months. Regarding non-federal capital, LUMA anticipates that the conclusion of an ongoing rate case will provide clarity on the budget amounts that may become available to prioritize investments over fiscal years FY2026 – FY2028.

4.0 The Puerto Rico Transmission System

4.1 Existing Transmission Facilities Descriptions

This section includes a brief narrative description of the existing electric transmission system. The Puerto Rico electrical grid is a highly complex, interconnected system powering nearly 1.5 million customers across the island. An illustration of the LUMA transmission and substation facilities is provided in Appendix A.

LUMA plans and operates a transmission system with an extensive network of transmission lines at 230kV (424 miles), 115kV (711 miles), and sub-transmission 38kV (1563 miles). The transmission system is a true network interconnecting large central station generation plants in Costa Sur, Aguirre, San Juan and other areas to the load centers through the 50 Transmission Substations (Transmission Centers or TC's), and supplying loads over 299 substation sites, which supply 431 distribution substation transformers powered directly from 38kV lines or at large substation sites. The transmission and substation infrastructure also includes telecommunications, grid control devices and relay and protection systems to operate grid assets in a controlled and cohesive fashion. The physical T&D system together with the telecommunications, protection and control devices together make up the grid—as complex as the human body—to provide near-real-time data, visibility and intelligence to grid operators, but simultaneously performing autonomous functions to keep grid assets and the public safe.

4.2 Discussion of Existing Transmission Constraints on Electricity Transfers

To manage a safe and reliable grid, the system must have available capacity to interconnect existing and future loads and generation projects to enhance grid reliability and flexibility. The grid's capacity to connect new loads depends on the transmission, substation and distribution capacity available at the requested point-of-interconnection. The grid's capacity for interconnecting new generation depends on the specific resource and technology (e.g., solar, storage, or both), specific point-of-interconnection, and how that generation interconnection is planned to operate. Note that each successive load or generation interconnection reduces capacity for a future project to connect. To interconnect new loads, and variable renewable generation facilities, an interconnection study is required, and any network upgrades required to address grid constraints to connect safely and reliably are communicated to the developer.

The transmission system provides an efficient and reliable interconnection between the generation sites and the load centers throughout the island and functions as a highway for electricity between major substations from one region to the other. Transmission lines transfer power from generation units to major Transmission Centers (TCs), then to customers and communities in every part of the grid. Like a highway, grid traffic varies by time of day, by month, and by year, with summer heat and humidity driving congestion due to customer utilization at late evening peak demands. Also, similar to a highway, there are lightly utilized periods of grid traffic, which typically occur between February and May, when minimum daytime loads are reducing each year due to over 1.2GW of customer connected rooftop solar offsetting demand – residential and small-scale solar is growing at 300-400MW each year.

One major emerging risk may constrain the ability of the transmission system to interconnect additional variable renewable generation and risks the stability of the entire grid. This emerging risk occurs when existing generators are forced to operate at their minimum output value and cannot be dispatched lower due to equipment design and operational limitations. This is a major concern because (a.) any contingency

that results in loss-of-load can lead to system instability and widespread blackouts, and (b.) these generators have long start-up times so they cannot shut down since they are still needed to serve evening peaks on lightly loaded days. This may limit ability to interconnect future variable renewable generation and may require both large-scale and small-scale batteries to follow a prescribed charging schedule, to charge during the minimum daytime low-load hours.

Studies have identified constraints on the ability to interconnect new generation projects and facilitate power transfers across the grid. These studies are the resultant overloaded substation transformers and transmission line segments identified in a System Impact Study for a specific project or group of projects. Since each generator interconnection request and technology is unique, each must be analyzed to ensure that the new requests, and any concurrent projects under development can be interconnected safely and at a reasonable cost while maintaining a reliable, safe, and secure grid. LUMA's focus is on safety, reliability, and affordability for all customers and developers, and in facilitating cost effective resource integration into the grid. A customized list of requirements is provided to each customer or developer who requests an interconnection to the Puerto Rico grid. These requirements include interconnection facilities required at the point of interconnection, and network/capacity upgrades to the substations and transmission lines around the new generation request to ensure the safe and reliable interconnection for that facility to operate at its rated output. LUMA has completed impact study analysis for Tranche 1, 2, and 4 renewable energy projects, the Energiza project (studied at 460MW), and proposed ASAP battery additions to existing power producers, and proposed Genera Battery Energy Storage (BESS) and gas peaker projects. In all cases, facilities have been recommended. In most cases involving increased capacity, network upgrades have been identified and recommended to the project developers.

4.3 Discussion of Planned Transmission Facilities

4.3.1 Developing Mitigation Options to Resolve Violations Identified

As part of its annual process LUMA conducted a comprehensive Transmission Planning Assessment (TPL Assessment) started in 2024 to assess the years 2025 and beyond to identify necessary upgrades to the transmission system to meet industry performance standards. The 2025 TPL Assessment targeted increasing the reliability and resilience of the transmission network by identifying those investments including new transmission lines and transformers, reconductoring existing lines and upgrading transformer capacities, restoring out-of-service transmission lines and transformers, and rebuilding and reconfiguring substations to more reliable designs. The model years studied were years 1 (2025) and 5 (2029). Note that since the PSS®E Analysis of the preferred resource plan will be presented in November 2025, only the current system gaps and required mitigations will be discussed here.

The TPL Assessment involved extensive power flow analysis, contingency analysis including running 982 unique N-1 contingencies, and 77,006 permutations of N-1-1 contingencies. Note that N-1-1 assumes one element is initially out of service (adjustments are allowed to avoid overloads or voltage violations), then another element trips subsequently. These simulations evaluate system performance under various operational scenarios and identified vulnerabilities. Since urgency in project proposals center around resolving N-1 criteria violations, only those are presented in tables below. Separate contingency cases have been created to analyze natural disasters and wide area outages.

The solution options that were applied to mitigate thermal overloads and voltage violations (which are violations of thermal and voltage criteria based on contingency sets defined in Appendix B "LUMA Transmission Planning Criteria") include:

- **New Transmission Lines**: Proposals for new transmission lines to enhance connectivity and reduce congestion in critical areas of the grid. New lines may require new ROW if existing ROW does not provide adequate clearances.
- **Reconductoring Existing Lines To Increase Capacity**: Upgrading existing transmission lines with higher capacity conductors to increase their current ratings and improve overall system performance.
- **Restoring Out-of-Service Transmission Lines:** Bringing previously decommissioned transmission lines back into service to increase capacity and improve system reliability.
- **Substation Rebuilds**: Rebuilding and upgrading substations to enhance their capacity, reliability, and ability to integrate renewable energy sources.
- **Additional Transformers:** Installing new transformers to increase the capacity and flexibility of the transmission network, allowing for better load management and integration of renewable energy sources.
- **Restoring Out-of-Service Transformers:** Bringing previously decommissioned transformers back into service to enhance system reliability and capacity.

4.3.2 Study Results and Mitigation Required

The assessment shows that 26 critical contingencies result in significant overloads of transmission lines; note that these overloads quite often result in cascading where the first element trips, and other elements overload severely leading to regional and/or island wide disturbances. The assessment shows 17 critical contingencies result in significant voltage violations; note that the voltage violations are often regional, leading to voltage collapse of the entire region if a single element trips.

The findings are inputs to developing proposed solutions are crucial for ensuring the transmission system's ability to meet future demand, support generation and renewable energy integration, and improve island-wide reliability transmission grid performance. By addressing thermal overloading and voltage violations, LUMA aims to provide a robust and resilient transmission network capable of supporting Puerto Rico's evolving energy needs. These violations are also compared against physical assets in poor condition, and those that support grid resilience when prioritizing projects.

Table 1 provides a summary table of proposed thermal solutions by project type to resolve the thermal violations. The specific contingencies and overloaded facilities are provided in Table 26 (CEII) of this report. Table 2 provides the list of the identified solutions based on voltage violations. The specific contingencies and resulting voltage violations are provided in Table 27 (CEII) of this report. Note that no new substations were proposed as a result of the 2025 TPL Assessment, but reconfigurations of existing sites are proposed to limit the customers impacted after an event at one of the proposed rebuild substations.

Table 1 TPL Assessment 2025 Summary of Proposed Thermal Solution by Project Type

Project Type	N-1
New Transmission Line	5
Reconductor Transmission Lines to Increase Capacity	20
Restoring Out-of-Service Transmission Line †	1
Substation Rebuild	3

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Project Type	N-1
Additional Transformer	3
Restoring Out-of-Service Transformers	0

*Note that 5 critical out-of-service Transmission Lines are planned to be restored with DOE funding.

Table 2 TPL 2025 Summary of Proposed Voltage Solution by Project Type

Project Type	N-1
New Transmission Line	4
Restoring Out-of-Service Transmission Line	0
Additional Transformer	1
Restoring Out-of-Service Transformers	0
New Fixed Shunt Capacitors	8
New Switched Shunt Capacitors	2
Station Reconfiguration	0
New Battery	2

Four new transmission lines have been identified as potential solutions to violations identified in the TPL Assessment. These four lines need to be proposed for future budget requests and evaluated for feasibility and routing studies if not other suitable alternatives can be identified. Table 3 shows the four new transmission lines and the terminal substations. No specific requirements for new Rights-of-Way have yet been determined, other than standard dimensions for 115kV facilities and 38kV facilities. Note that upon detailed feasibility analysis for each of these lines, the scope for these proposed new transmission lines needs to be defined in enough detail to initiate a project.

Table 3 Proposed New Transmission Lines from TPL Assessment

Line Name	Voltage	Length
Mora to Hatillo	115kV	22 mi
Monacillos to Canóvanas	115kV	12 mi
Barranquitas to Aibonito	38kV	5 mi
Comerio to Cidra	38kV	4.3 mi

As part of the TPL Assessment Night peak and Day peak loading conditions were considered to represent the worst-case loading of Puerto Rico, as shown in Table 4.

Table 4 TPL Assessment Night and Day Peak Loading Conditions

Near-term Base Case Models (2025)
Day-Peak
Night-Peak

4.3.3 Studies Supporting Large-Scale Generation and Renewable Integration

LUMA has performed Renewable Tranche studies to support Renewable Energy Targets in coordination with PREB and other stakeholders. Tranche 1 and 2 studies and technical evaluation have largely been completed. A summary table of the Tranche 1 projects is shown in Table 5.

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Table 5 Tranche 1 Renewable and BESS Projects

Project Name	Project Tag	Size (MW)	Technology	Interconnection Substation Name (POI)	Voltage (kV)
Salinas Solar	C-1-P	120	PV	CIRO Sectionalizer	115
Salinas (BESS) - ITC	C-2-E	250	BESS	CIRO Sectionalizer	115
Jobos Solar	A-1-P	80	PV	Jobos TC	115
Jobos (BESS) - ITC	A-2-E	110	BESS	Jobos TC	115
Coamo Solar	I-1-P	100	PV	Sectionalizer -Line 40300	115
Yabucoa	AK-1-P	32.1	PV	Juan Martin TC	115
Pattern Barceloneta Solar	W-3-P	70	PV	Barceloneta TC	115
Ciro Two Salinas	AD-1-P	68	PV	CIRO Sectionalizer	115
Guayama Solar Energy	AE-1-P	50	PV	Jobos TC	115
Tetris Power	AS-1-P	20	PV	Cambalache TC	38
Naguabo Energy Park	AZ-1-E	20	BESS	Daguao TC	115
Caguas Energy Storage	H-3-E	25	BESS	Bairoa Substation 3008	38
Penuelas Energy Storage	L-3-E	100	BESS	Costa Sur SP TC	115
Ponce Energy Storage	M-3-E	25	BESS	Juana Diaz TC	38
Yabucoa Energy Park -ITC	AX-1-E	20	BESS	Yabucoa TC	115
Pattern Barceloneta Storage	W-2-E	50	BESS	Barceloneta TC	115
Pattern Santa Isabel Storage	AA-2-E	50	BESS	Santa Isabel TC	115

LUMA also performed interconnection studies for the proposed Energiza facility, studying a proposed 460MW interconnection at the San Juan Steam Plant facility. Facility studies identified modifications to interconnection facilities that would be required to ensure the safe and reliable operation of the plant. System Impact Studies also identified required Network Upgrades that are needed before the plant is energized at 460MW to prevent the thermal overload and physical damage to existing 115kV and 38kV lines around the power plant. The San Juan Steam Plant Substation Rebuild is also an obligated FEMA project scheduled for rebuild.

LUMA is also in the process of completing studies for Genera BESSS and Peaker projects as previously discussed. A number of these studies for facilities with in-service dates in 2026 or prior have already been completed, and those with in-service dates of 2027 or beyond are in the process of being studied.

LUMA has also recently supported the restudy of specifically requested Tranche 1 generator interconnections seeking to expand the size of their initially proposed facilities.

4.3.4 Planned Transmission Facilities

To provide visibility to LUMA's planned project portfolio (before the IRP Preferred Resource Plans are evaluated for T&D impact in a separate filing), the following project list is provided in Table 6 This list of facilities was included in Long-Term Investment Plan records and budget requests. The transmission lines that were anticipated to be rebuilt by leveraging FEMA funding are identified. Those that remain with active FAAST numbers are identified (these are proceeding through project development), and are differentiated from lines for which FAAST numbers were cancelled by FEMA in August 2025 (these are on hold with no design engineering work being performed). LUMA will continue to evaluate project status and anticipated timelines given recent developments and available prioritized funding.

Table 6 Transmission Line Facilities in the Long Term Investment Plan, both Active and Recently On Hold

Line	Project Name
Active Projects with FAAST numbers	
100 & 200	100 & 200 - Ponce TC to Jobos TC
1900	1900 - Dos Bocas HP to San Sebastian TC
2400	2400 - Dos Bocas HP to America Apparel (Caonillas)
3100	3100 - Monacillos TC to Sabana Llana TC
5400	5400 - Rio Blanco HP to Daguao TC – Vieques - Culebra
8200	8200 - San Juan SP to Catano Sect.
9500	9500 – Palo Seco SP to Catano Sect
36100	36100 – Bayamon TC to Monacillos TC
36400	36400 - Dos Bocas to Ponce TC
On Hold Projects - FEMA Cancelled FAAST numbers	
500	500 - Ponce TC to Costa Sur SP to Tallaboa*
700	700 - Costa Sur to Yauco
1200	1200 - Mayaguez GP to Yauco 2 HP
1500	1500 - Mayaguez GP to GOAB 1515
2200	2200 - Dos Bocas HP to Dorado TC
2700	2700 - Mora TC to Quebradillas Sect
2800	2800 - Aguadilla Hospital Distrito Sect to T-Bone TO
3000	3000 - Monacillos TC to Juncos TC
3100	3100 – Sabana Llana TC to Fajardo
4100	4100 - Guaraguo TC to Comerio TC
9100	9100 - Guaraguao TC to Bayamon Pueblo Sect
11100	11100 - Canóvanas to GOAB
36100	36100 – Dos Bocas HP to Bayamon TC
36200	36200 - Fajardo to Rio Blanco
36200	36200 - Monacillos TC to Juncos
36800	36800 - Palmer Fajardo to Sabana Llana

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Similarly, the portfolio of substation projects under PBUT08 is impacted by FEMA funding project (FAAST) numbers being withdrawn. However, there is a sizable list of projects that are obligated on Table 7, and that need to be refined. Some that are started and in execution. And others that still need to be planned and whose timeline and scope will require PREPA and FEMA alignment before design engineering work can resume on Table 8.

Table 7 Active Substation Projects with Obligated Status

No.	Project Name
1	San Juan SP
2	Monacillo TC
3	Bayamon TC Breakers
4	Centro Medico Sect.
5	Rio Grande Estates
6	Costa Sur SP Phase II
7	Sabana Llana TC
8	Tapia GIS
9	Catano
10	Vieques 2501
11	Culebra 3801
12	Costa Sur Breakers
13	Aguirre TC Bkrs
14	Aguirre TC Phase II

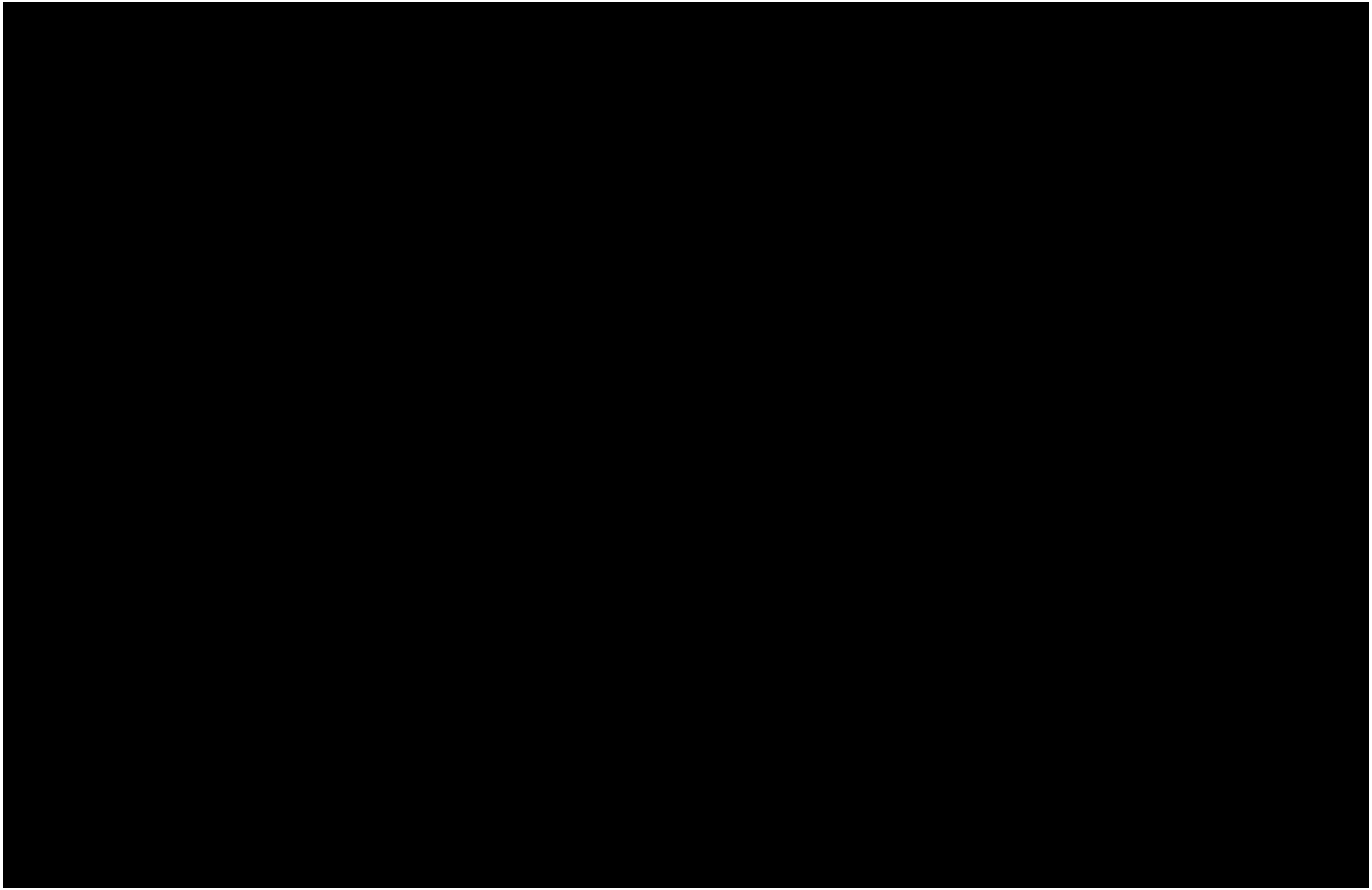
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Table 8 Substation Facilities In Development and On Hold

No.	Project Name
	Active FEMA Projects
1	Viaducto TC
2	Llorens Torres Sect.
3	Jobos TC
4	Cachete
5	Maunabo TC / Maunabo 4301 (Floodway Relocation)
6	New Vieques
7	New Culebra
8	Caparra
9	Conquistador
	On Hold Projects - FEMA Canceled FAAST Numbers
10	Acacias 6801TC (Floodway Relocation)
19	Anasco TC
17	Bayview Sectionalizer (Floodway Relocation)
34	Berwind TC
32	Caguas TC
25	Cambalache TC (Floodway Relocation)
26	Canas TC
14	Charco Hondo (Floodway Relocation)
27	Dorado TC + La Virgencita (Floodway Relocation)
16	Egozcue
20	EPC - Bayamon TC – Phase 2
15	EPC - New Guayanilla Substation (Costa Sur Phase 3)
22	EPC - New Salinas Substation (Aguirre Phase 3)
29	Esc. Miguel Such
24	Fajardo TC
37	Guaynabo Pueblo Substation
23	Juana Diaz TC
28	Manati TC - Phase II
11	Monterey
36	Morovis
31	Palo Seco
18	Ponce TC
21	Puerto Nuevo
35	Punta Lima Sect.
12	Santa Isabel TC (Renewables & Capacity)
13	Unibon (Corozal)
38	Venezuela Sectionalizer
30	Victoria TC 7008 (Elevated Control House)
33	San Jose (Floodway Relocation)
34	Mayaguez TC

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Figure 1 Transmission System Map



5.0 The Puerto Rico Distribution System

5.1 Description of Existing Distribution Facilities

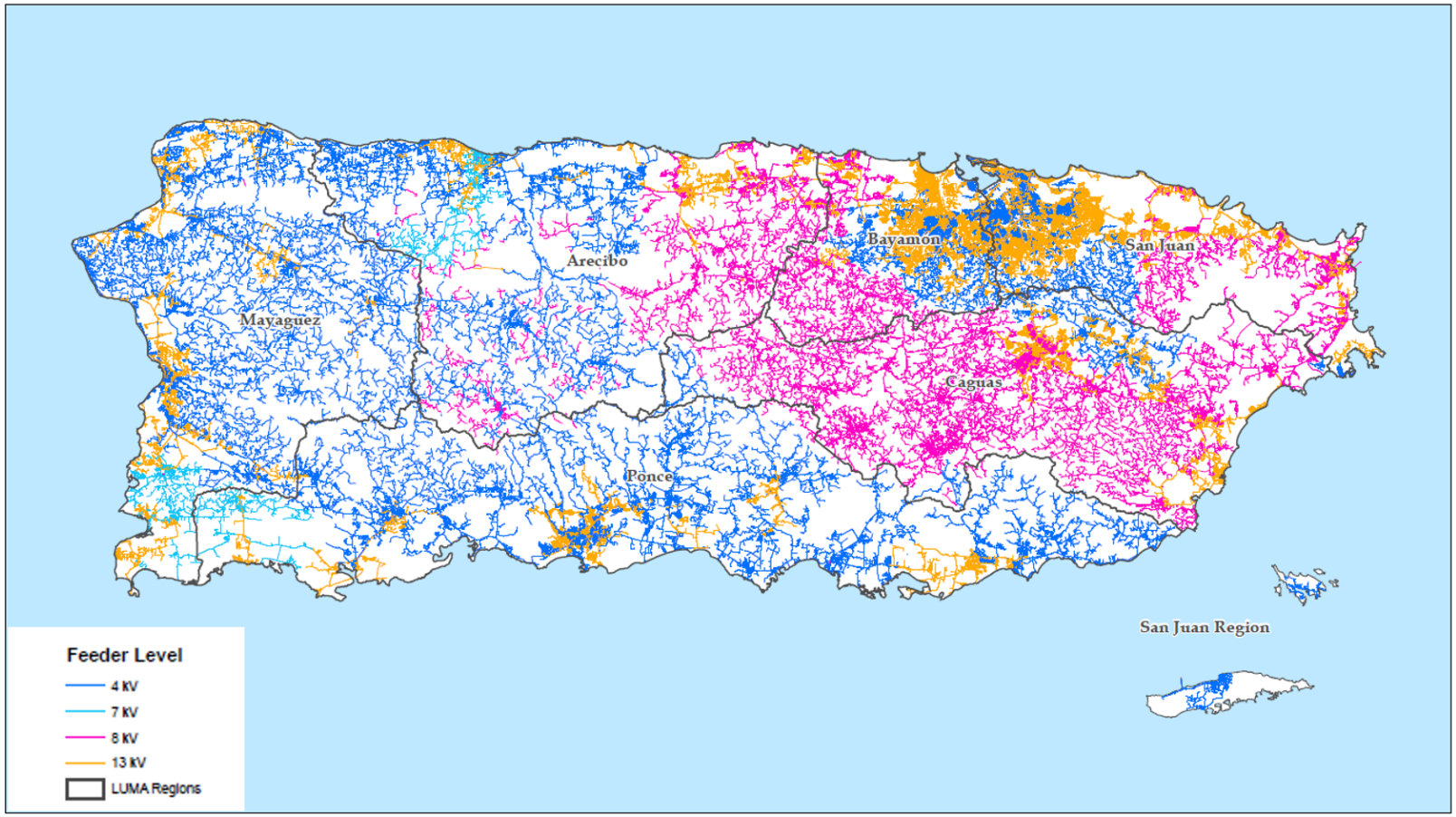
Puerto Rico's electric distribution system includes distribution substations, primary distribution lines, customer transformers, and secondary conductors that serve the customer meter. Distribution substations transform, or step down the voltage from transmission voltages (115 or 38kV) to primary distribution voltages (13.2, 8.32, 7.2, 4.8 or 4.16kV), and have associated substation switchgear, equipment and infrastructure. Primary distribution lines originate at the substation and the circuits directly serve customer loads through a distribution transformer which may be customer or utility-owned depending on the size of the customer. Distribution transformers step down the primary to a secondary voltage (e.g., 13.2 kV to 240/120V), often referred to as utilization voltage, for use by end-use customer loads. Puerto Rico's distribution system is currently comprised of 342 distribution substations that supply loads to 1,127 distribution circuits (also referred to as feeders). These substations and feeders are energized at one of five primary voltage levels: 13.2 kV, 8.32 kV, 7.2 kV, 4.8 kV or 4.16 kV. Table 9 below shows a breakout of the number of substations and feeders per voltage level. LUMA manages six operational regions across Puerto Rico: Arecibo, Bayamón, Caguas, Mayaguez, Ponce and San Juan. Table 9 shows a map of the Operational Regions and Districts.

Table 9 Distribution Substations and Feeders by Primary Voltage Level

Voltage level	Number of substations	Percent of total	Aggregated capacity (MVA)	Percent of total	Number of circuits	Percent of Total
4.8 kV	1	0.3%	6.25	0.1%	2	0.2%
4.16 kV	176	51.5%	1,693.6	31.8%	612	54%
7.2 kV	6	1.75%	74.9	1.4%	18	1.6%
8.32 kV	54	15.8%	598.4	11.2%	164	15%
13.2 kV	105	30.7%	2,955	55.5%	331	29%
Total	**342**	**100%**	**5,328.15**	**100%**	**1,127**	**100%**

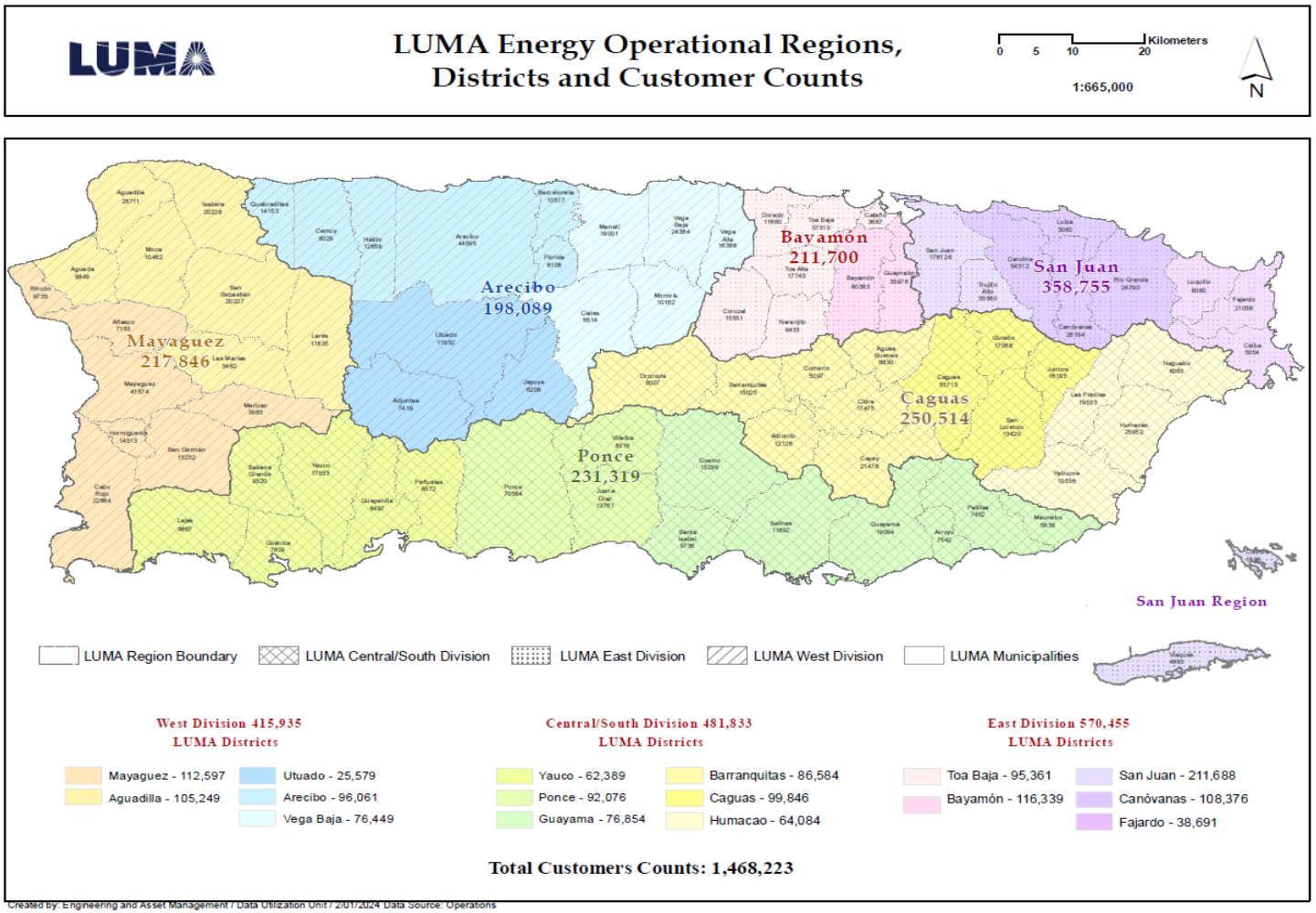
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Figure 2: Puerto Rico Distribution Circuits by Voltage



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Figure 3: LUMA Operational Regions and Municipalities with Customer Counts



**The customer counts presented are based on best estimate per region. Note that there are an estimated 166,000 meters that are known to be missing. Missing meters are actively being identified, and customer data sets being updated accordingly.

5.1.1 Existing Distribution Substations

Distribution substations change the voltage level from the transmission level to the primary distribution level by means of a transformer. These transformers are supplied by the transmission system (on the high side). The transformer supplies a distribution bus which typically feeds three (3) to five (5) distribution circuits. Table 10 shows the association of substations per voltage level for each LUMA Operational Region.

Table 10 Distribution Substations by LUMA Operating Region

Region	Voltage Level	Number of Substations	Aggregated Capacity (MVA)	Customer Estimates**
Arecibo	**All**	**37**	**492**	**198,089**
	13.2 kV	7	164	
	8.32 kV	9	111	
	7.2 kV	2	33	
	4.16 kV	19	181	
Bayamón	**All**	**48**	**3852**	**211,700**
	13.2 kV	7	79	
	8.32 kV	7	79	
	4.16 kV	19	203	
	4.8 kV	1	6	
Caguas	**All**	**57**	**770**	**250,514**
	13.2 kV	14	330	
	8.32 kV	35	381	
	4.16 kV	8	59	
Mayaguez	**All**	**58**	**689**	**217,846**
	13.2 kV	14	302	
	7.2 kV	4	72	
	4.16 kV	40	345	
Ponce	**All**	**50**	**590**	**231,319**
	13.2 kV	11	255	
	4.16 kV	39	335	
San Juan	**All**	**93**	**1846**	**358,755**
	13.2 kV	38	1236	
	8.32 kV	3	28	
	4.16 kV	52	582	

Existing distribution substations vary in size, voltage levels, and configurations. For example, substation transformer capacities can vary from 4 MVA to 44.8 MVA, with typical capacities varying by voltage level: 4.16 kV and 8.32 kV substations typically use transformer with capacities in the 7.5 MVA to 11.3 MVA range, while 13.2 kV substations typically have transformers with 22.4, 33.6, or 44.8 MVA of capacity. A site may have one or more distribution transformers. Single-transformer distribution substations predominate throughout the Puerto Rico grid. Larger Transmission Centers may have multiple distribution transformers; however, it is common for each transformer to operate at a different distribution voltage

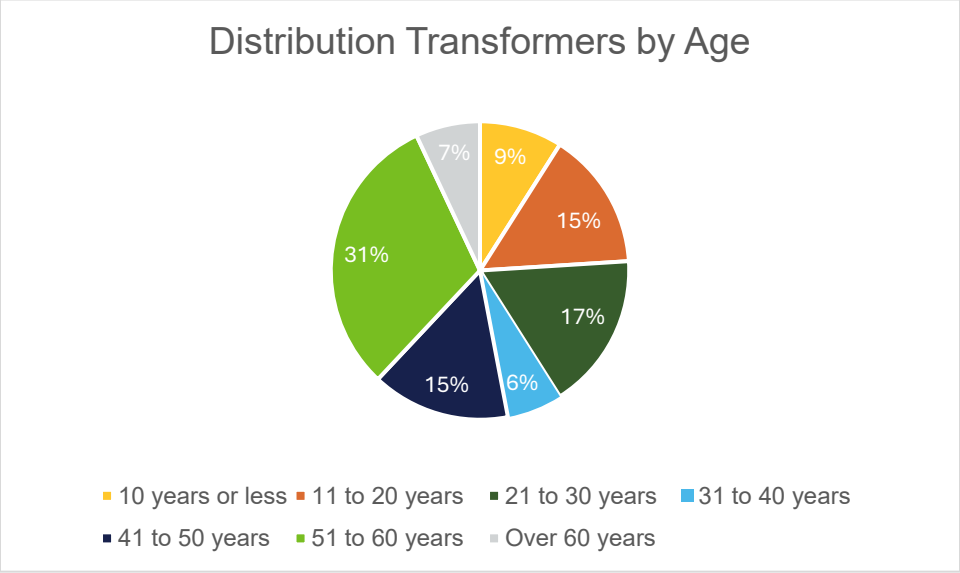
level, so redundancy, and therefore industry normal reliability, is not inherent in existing substation designs. Table 11 below shows the number of sites with single or multiple distribution transformers.

Table 11 Transformer Counts at Substation Sites

Distribution transformer counts	Number of distribution substation sites	Number of distribution transformers
1	225	225
2	46	92
3	7	21
4	1	4
Subtotals	279	341

Distribution transformer ages vary significantly, with approximately half the fleet at 40 years or older. Figure 4 below depicts distribution of transformers by age. The aging transformer fleet that was historically not well-maintained increases the likelihood of catastrophic transformer failure. The prevalence of single-transformer sites, or even multiple transformers at a site but operating at different distribution voltages means that a transformer failure results in extended outage impact and duration to customers.

Figure 4 Distribution Transformers by Age Group

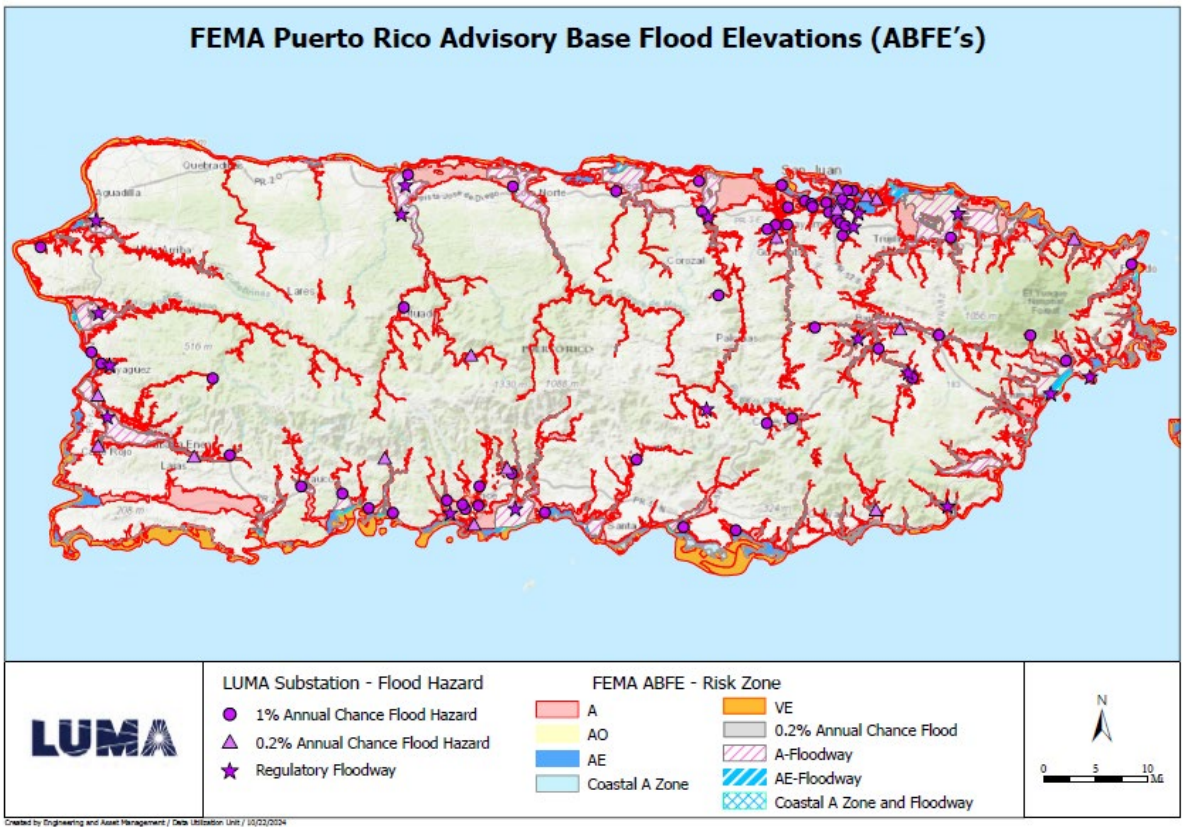


The factors above impact the reliability design of a substation. Single transformer stations are generally less reliable, since customers experience an outage for planned or unplanned loss of the transformer. This is especially true where adjacent circuits have no ties and when adjacent circuits are of different voltage levels. Multiple transformer stations are generally more reliable and are an industry planning standard. However, this is only true when the multiple transformers at the substation can provide redundancy and backup to each other; for example, loads connected to the first transformer can be

transferred to the adjacent unit for planned maintenance or due to unplanned failure. Again, the ability to transfer to adjacent units is not possible if the units are different sizes and voltage levels, which is often the case in Puerto Rico's grid.

LUMA has identified 87 of its 299 substation sites with flooding risk based on the FEMA Advisory Base Flood Elevation (ABFE) maps. Eighteen of these sites are in areas identified as a Regulatory Floodway, which represents a high probability of flooding – many have flooded in each of the recent severe weather events experienced in Puerto Rico. Of the remainder, 55 are in 1 %, and 14 sites in 0.2 % Annual Chance of Flood Hazard respectively as displayed in Figure 5. Substations located in Regulatory Floodways are planned to be relocated, while those in 1 % and 0.2 % Annual Chance of Flood Hazard must be evaluated and mitigated using preventive barriers, equipment elevation, or relocated to address flooding hazards. Figure 5 illustrates the FEMA ABFE map for the island of Puerto Rico.

Figure 5 Map Showing FEMA Flood Zones



5.1.2 Existing Distribution Feeders

A distribution feeder originates at a distribution substation and has historically been designed to be radial, one-way power supply to the customer loads. Feeders can consist of overhead infrastructure that includes poles, conductors, and supporting insulators and hardware, or underground infrastructure, or a combination of both. Generally, rural areas with long circuits and sparse loads are fed predominantly by overhead feeders, while suburban and urban areas are fed by a combination of overhead and underground feeders. Newer residential and commercial developments typically feature underground distribution circuit infrastructure.

The main portion of a distribution feeder is called the mainline or backbone and typically uses larger conductor sizes to support a larger volume of customer loads. Like a tree, the circuit typically branches further away from the substation, also known as taps or lateral circuits, which extend out to supply adjacent areas. These lateral circuits typically use smaller conductor sizes as a function of the load served. Feeder mainlines are three-phase, while laterals can contain one, two, or three phases, depending on the load and types of loads connected. Urban feeders often have multiple tie points. Rural feeders, particularly those in mountainous areas, have limited or no tie points.

The reliability improvement and strengthening of distribution feeders involve a series of design and technology investments. Feeder extensions and feeder ties create connections to adjacent feeders. These are often operated as normally open tie points, but in the event of a fault in one feeder section, portions of the load can be transferred to the healthy adjacent feeders, while only the customers on the faulted section remain out of service until repairs can be made. Strengthening these feeders involves rebuilding the backbone and selected laterals to a higher wind-loading standard to withstand severe storms as well as the deployment of protection and automation and sensing technology, as discussed subsequently. Covered conductors (such as Hendrix or spacer cable) are used in areas with heavy vegetation cover to reduce the number of vegetation-induced outages. Undergrounding can also provide security from both wind and vegetation-related outage causes. Additionally, the feeder protection and automation technologies can also help improve distribution circuit reliability.

5.1.3 Distribution Feeder Protection

Feeder mainlines are protected by a circuit breaker at the distribution substation. Out on the circuit, three-phase reclosers are installed strategically along the mainline, or larger laterals, to provide multiple zones of protection, and to sectionalize the feeder. In this case, only the nearest recloser will operate to clear a fault, reducing both the number of outages and the duration of outages experienced by all customers on the circuit.

Single-phase laterals are protected by fuses or by single-phase reclosers. Reclosers and fuses are installed to reduce the number of customers affected by an outage, in addition to protecting against faults. These devices are coordinated so that the first device upstream of a fault operates first to isolate the faulted segment. More details are provided in the Advanced Grid Technologies discussion.

5.1.4 Distribution Feeder Voltage Control

In a well-designed distribution system, a variety of devices operate together to control feeder voltage and supply reactive power balance. Substation transformers may have load-tap changers that can adjust automatically to regulate source-end voltage, while capacitor banks and voltage regulators are installed in distribution feeders to maintain the voltage at acceptable levels, +/- 5 percent deviation from nominal at the customer service entrance in accordance with the American National Standards Institute (ANSI) C84.1. Voltage boosters (transformers that provide fixed 5 percent voltage increase) are used in selected grid applications. Voltage performance of a distribution feeder varies, but are typically driven by operating voltage, conductor size, and circuit length. For example, feeders energized at 13.2 kV typically have larger wire size and therefore see acceptable voltage regulation across the entire feeder. This example feeder may employ capacitor banks for power factor correction and to maintain voltage at acceptable levels. The higher voltage level, coupled with the use of higher capacity conductors typically found on these feeders, leads to reduced voltage drop.

Conversely, feeders energized at lower voltage levels, particularly 4.16, 7.2, and 8.32 kV, are more susceptible to voltage drop along the circuit. This is especially true with older infrastructure where smaller wires, and/or very long radial circuits serving remote communities are commonplace. Also characteristic of feeders serving remote communities are single-phase and two-phase laterals along the long, radial feeder, which leads to large imbalances in the three-phase system. This combination of factors may lead to areas experiencing low voltage (below the ANSI-specified ranges) during heavy demand periods. The characteristics of lower operating voltage levels, longer circuits, and unbalanced single and two-phase laterals require higher load currents per unit of demand and unbalanced flows on each phase, which results in higher voltage drop (due to impedance) along the feeder. These circuits depend on the use of voltage regulators and capacitor banks to maintain acceptable voltage along the feeder.

Among the investments LUMA is making to provide more reliable service and manage voltage and reactive power flows across its system are technologies like switchable capacitor banks, transformers with Load Tap Changer (LTC) capabilities, and upgrade line voltage regulators. Additionally, LUMA has planned investments in tools and technology that provide visibility and control of the system of individual circuit level components, and down to the individual customer level. Investments that provide system and circuit level visibility and control include an upgraded Energy Management System (EMS) and functionality including an Advanced Distribution Management System (ADMS), and Distributed Energy Resource Management System (DERMS). At the neighborhood and individual customer level, investments like Advanced Metering Infrastructure (AMI) and smart meters will enhance visibility into voltage performance and both individual and aggregate customer demand. These capabilities will enable more accurate planning and forecasting thereby improving the identification and mitigation of potential issues before they arise.

5.2 Description of Existing Distribution Infrastructure by Primary Voltage Level

5.2.1 13.2 kV Distribution Infrastructure

The highest primary voltage level on the island is 13.2 kV. Widespread use of this voltage level on the island began in the 1960s to early 1970s and is predominant in the major metropolitan areas (San Juan Metro Area, Caguas-Humacao Region, Ponce, Mayaguez) and the urban centers along the coastline. Except for areas in the Caguas Region, the central part of the island is mostly devoid of substations or circuits energized at this voltage level. Although second in terms of number of distribution substations, it is first in terms of aggregated transformer capacity, with 55 percent of aggregated distribution transformer capacity. Typical 13.2 kV substation transformer sizes are 22.4 MVA, 33.6 MVA and 44.8 MVA, and average transformer age is 27 years. The relative (to other voltage classes) lower average age of 13.2 kV infrastructure means it is not as prone to age-related equipment failure, but still subject to equipment failures resulting from poor maintenance practices. Distribution feeders energized at 13.2 kV have more load carrying capacity, better voltage regulation and more capacity to absorb distributed generation than the other voltages employed on the island. These feeders are typically urban and suburban feeders serving high load density areas. Feeder mainlines (backbones) are typically built with higher ampacity conductors, and a significant portion of underground distribution infrastructure is energized at this voltage level. All new distribution loads are now connected to the 13.2 kV whenever possible. LUMA plans to continue with efforts to standardize the distribution system to 13.2 kV by converting existing substations and circuits currently energized at lower voltage levels to 13.2 kV. Currently, 331 feeders and 562,070 customers are served at 13.2 kV. Some 13.2 kV feeders have step-down transformers that feed sections at lower primary distribution voltages.

5.2.2 8.32 kV Distribution Infrastructure

The 8.32 kV distribution system is concentrated in the central-eastern part of the island. It is the predominant voltage level in the Caguas Region and supplies significant portions of the San Juan, Bayamón, and Arecibo Regions. It ranks third in both the number of distribution substations and the aggregated capacity. Typical distribution transformer capacities are 10.5 MVA and 11.3 MVA, and average transformer age is 37 years which means many are beyond their designed useful life. The average age of the transformers means LUMA's 8.32 kV distribution grid is beyond its useful life design and prone to increasingly frequent equipment failures due to both the age and condition of poorly maintained assets. Distribution feeders energized at 8.32 kV predominantly serve more rural areas in the Caguas, San Juan and Bayamon Regions, and account for 164 feeders and 304,038 customers. Due to the lower voltage level, and the fact that many feeders employ lower capacity conductors, 8.32 kV feeders have lower load carrying capacity and less ability to connect distributed generation when compared to 13.2 kV circuits. Voltage regulation issues (undervoltage) may also occur, particularly on long, rural feeders with low-capacity conductors.

5.2.3 7.2 kV Distribution Infrastructure

The 7.2 kV distribution system consists of six (6) substations and eighteen (18) feeders serving 36,900 customers. The six (6) distribution substations are in the municipalities of Arecibo (2 substations), Cabo Rojo (3 substations), and Lajas (1 substation) and their 7.2 kV circuits extend into adjacent municipalities. These substations account for 1.4 percent of the aggregated distribution substation capacity in the island. Typical transformer capacity is 10.5 MVA, and average transformer age is 39 years. The distribution feeders served by these substations primarily serve suburban or rural areas, with some feeders serving more urban areas near the substation. As in the case of 8.32 kV feeders, these circuits have less load carrying capacity and less ability to connect distributed generation.

5.2.4 4.16 kV Distribution Infrastructure

Distribution infrastructure energized at 4.16 kV is predominant in the Bayamón and San Juan Regions (including the San Juan metropolitan area from Carolina to the east to Toa Alta in the west), the Mayagüez and Ponce Regions, as well as supplying a significant portion of the Arecibo Region and a smaller portion of the Caguas Region. There are more total substations with a secondary voltage of 4.16 kV than any other voltage, but there is lower substation aggregated customer demand than the 13.2 kV system. There are 613 feeders serving 565,133 customers. Typical 4.16 kV substation transformer capacities are 10.5 MVA and 11.3 MVA, and average transformer age is 44 years which means there are many end-of-life assets in substations. Many 4.16 kV feeders have lower capacity conductors, and 4.16 kV feeders have the lowest load carrying capacity and less ability to connect distributed generation than any other voltage level. Voltage regulation issues, particularly undervoltage, are more likely to occur in these feeders, particularly in long, radial feeders typical of the more rural areas.

5.2.5 4.8 kV Distribution Infrastructure

One distribution substation operating at 4.8 kV exists in the municipality of Bayamón. This substation supplies two (2) feeders and a total of 82 customers. This substation and its associated feeders are high-priority candidates for Strategic Voltage Conversion to 13.2kV.

LUMA is continuing efforts to standardize distribution infrastructure to 13.2 kV. All new primary distribution equipment (breakers, switchgear, insulators, etc.) is being procured at the 15 kV voltage class.

5.3 Existing Distribution System Performance

5.3.1 Thermal Performance of Existing Feeders and Transformers

LUMA has completed a system-wide assessment of its distribution system with Area Planning studies over the last 3 years. Area Plan studies evaluate the present condition of the distribution system and its ability to supply future forecasted load, both under normal conditions and planned switching during emergencies to provide high reliability performance. An integral part of these Area Planning studies are the load flow studies of the feeders to evaluate the voltage profile and load along all circuit sections. Voltage and thermal violations are identified, and mitigation measures proposed, which include both operating adjustments and infrastructure upgrades. These mitigation measures become the foundation for feeder or substation rebuild projects. Mayaguez and Ponce have high numbers of circuits with voltage violations, while Mayaguez, Bayamon, and Ponce have high concentrations of circuits experiencing thermal overloads. A summary of these findings for distribution circuits is provided in Table 12.

LUMA analyzed distribution substation load profiles and identified substations at or exceeding 90 percent of maximum capacity. Area Planning studies also identified substations at, or forecasted to exceed, 90 percent of rated capacity, and those nearing capacity using projected load growth. Also, evaluating active proposed customer new business projects helps identify priority substation transformers that are forecasted to exceed 90 percent of rated capacity. In all, 25 substations currently exhibit peak demands at or over 90 percent of rated capacity, while an additional 19 substations were identified to exceed 90 percent of rated capacity in the next 1-3 years based on new-business requests for interconnection. Area Planning studies identified an additional 22 substations with the potential of exhibiting peak demand at or exceeding rated capacity in a 5-year planning window. Substations with high thermal loading appear equivalent across all regions. A summary of these findings is included on Table 13 by region and distribution voltage level.

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Table 12 Circuit Voltage and Thermal Violations Identified By Region

Region	Voltage Level (kV)	Voltage Violations	Loading Violations
Arecibo	**All**	**39**	**12**
	13.2	2	2
	8.32	14	2
	7.2	1	0
	4.16	22	8
Bayamón	**All**	**38**	**35**
	13.2	11	15
	8.32	10	2
	4.16	17	18
Caguas	**All**	**36**	**17**
	13.2	5	3
	8.32	26	13
	4.16	5	1
Mayagüez	**All**	**82**	**40**
	13.2	14	9
	8.32	0	0
	7.2	2	0
	4.16	66	31
Ponce	**All**	**76**	**34**
	13.2	10	2
	8.32	0	0
	7.2	1	0
	4.16	65	32
San Juan	**All**	**33**	**26**
	13.2	9	13
	8.32	5	3
	4.16	19	10
Subtotals	**-**	**304**	**164**

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Table 13 Substations with Peak Demand above 90 Percent By Region and Distribution Voltage Level

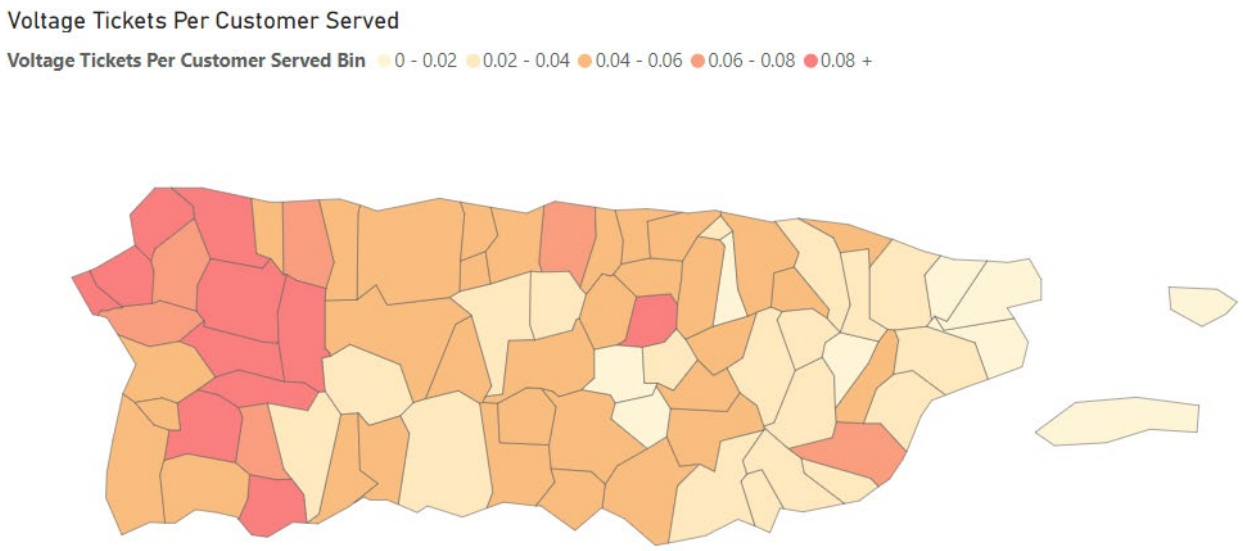
Region	Voltage Level (kV)	No. of Substations	Loading Over 90%	Loading Forecasted Over 90%	Area Planning Substations Over 90%
Arecibo	**All**	**9**	**4**	**3**	**2**
	13.2	1	0	1	0
	8.32	3	1	2	0
	7.2	1	1	0	0
	4.16	4	2	0	2
Bayamón	**All**	**9**	**2**	**3**	**4**
	13.2	3	0	1	2
	8.32	3	1	1	1
	4.16	3	1	1	1
Caguas	**All**	**11**	**4**	**3**	**4**
	13.2	3	1	2	0
	8.32	6	2	10	4
	4.16	1	1	0	0
Mayagüez	**All**	**14**	**6**	**2**	**6**
	13.2	2	1	0	1
	4.16	11	5	2	5
Ponce	**All**	**12**	**6**	**2**	**4**
	13.2	1	1	0	0
	4.16	11	5	2	4
San Juan	**All**	**11**	**3**	**6**	**2**
	13.2	8	2	6	0
	8.32	0	0	0	0
	4.16	3	1	0	2

5.3.2 Voltage Performance (Heat Mapping Customer Calls)

LUMA's distribution grid is limited in its ability to maintain customer voltage to industry standards. Figure 6 maps the rate of customer call tickets referencing high or low voltage issues on a heat map by customers served. One contributing factor is the lack of maintenance and upkeep of substation transformer LTC assets, many of which were disabled due to skipped maintenance cycles, or past failure but never replaced. A second contributing factor is a lack of asset records and maintenance, as well as distribution feeder voltage and reactive power control assets such as capacitor banks and voltage regulators. These devices asset records in models and operational datasets are often inconsistent with field condition, and many are out of service due to failure or damage. A third contributing factor impacting customer voltage performance is the distributed energy resources that connect to the distribution circuits without prior study and approval by knowledgeable utility personnel. Figure 6 illustrates a heat map showing voltage tickets per customer served for each municipality. This check confirms details from the Area Plan studies and

feeder level power flow studies and assessments that indicate the Mayaguez region experiences high concentrations of low voltage during nighttime and evening peak loads.

Figure 6: Heat Map displaying customer voltage tickets per customer served (01/2024 data)



Another common practice in the Puerto Rico grid that impacts voltage performance is the prevalence of multiple distribution voltages (which is not a common practice across the industry) and the step-down transformers, also referred to as voltage converters, that are used to allow circuits originating from a substation at one voltage level (e.g., 8.32 kV) to convert to a voltage (e.g., 4.16 kV) to supply a neighborhood or small load pocket. Step-down transformers provide necessary flexibility to supply loads at different voltage levels; however, these devices fail frequently and become single-points-of-failure with negative reliability consequences. Without an adjacent circuit at the “stepped down” voltage level, there is no way to restore the customer loads when a converter fails except to replace the converter.

The design and operation of the distribution grid as described in this section present physical limitations on achievable reliability improvement. The combination of substation transformers and circuits energized at different voltage levels, and the long and radial distribution circuits with limited feeder ties because circuits operate at different voltage levels creates operational and logistical challenges to the reliable system operations. Equipment (such as service transformers) must be procured, and the inventory must be maintained for each voltage level. Additionally, the step-down transformers described previously are single-points-of-failure affecting large amounts of customers, especially in rural and mountain communities.

5.4 Description of Planned Distribution Facilities

LUMA is executing multiple efforts, organized under a portfolio of programs (Program Briefs) that will result in enhancements to the distribution system. These programs feature a mix of federally funded and non-federal capital (NFC) projects that address distribution substation and feeder infrastructure among others. The main programs impacting the distribution system, are described below.

5.4.1 Substation Rebuilds (PBUT8)

The Substation Rebuild program focuses on the rebuilding of existing substations that are in poor physical condition, the rebuilding of substations with a history of operational deficiencies, the mitigation of flood risk where applicable, and the relocation of substations with a high risk of flooding when flood mitigation alone is not an option.

Substation rebuild projects targeted under this initiative will include:

- Enhanced bus configurations, including main-and-transfer bus, ring bus, or breaker-and-a-half configurations to mitigate against the possibility of failure of a single element.
- Adoption of enclosed metal-clad and gas-insulated switchgear to resist exposure to extreme weather.
- Flood mitigation for substations located in flood hazard areas, or relocation of substations located in FEMA regulatory floodways.
- Use of standardized transformer configurations meeting latest industry standards.
- Adoption of technology such as intelligent substation automation and protocols.

Substation rebuild projects will provide additional benefits to the distribution system over existing distribution substation infrastructure. The revised bus configurations and enclosed switchgear will provide more reliable and resilient designs. Updated transformer specifications will better prepare the distribution system for increased penetration of distributed energy resources by requiring the use of distribution substation transformers with capacity to handle reverse power flow and increased harmonic levels expected from the increasing DER inverter penetration. Transformers with higher rated capacity under normal and overload conditions will also allow for projected load growth and will provide additional capacity to transfer out loads during substation maintenance or under contingencies.

Dual voltage transformers will be deployed when rebuilding substations with primary distribution voltages other than 13.2 kV, setting the way for the eventual conversion of the substations to 13.2 kV. Spare feeder positions will be standard, which will allow for future growth in the area and to provide additional reliability by allowing the spare breaker to carry the load of an existing feeder breaker undergoing maintenance or upon equipment failure. In areas with high load densities, and where feasible, substation design will consider space provisions for a future second transformer and associated switchgear. Major substations will feature a dual transformer configuration to provide additional reliability and resiliency by permitting to serve the load by either transformer in case of maintenance or contingencies. Three phase metering will be provided at the feeder heads, allowing for more precise monitoring of circuit load and provide more precise data for studies.

In addition to the substation rebuild projects included in the Long Term Investment Plan (LTIP), LUMA has identified the need for additional substation upgrades due to overloads, constrained capacity (refer to list of capacity constrained substations above), asset conditions and reliability issues. LUMA is currently performing substation assessments on the subset of the 299 substations not included in the LTIP to identify additional sites needing upgrades and recommended scope. LUMA will then determine which program (component replacement or substation rebuild) each potential project would fit into based on the total investment needed and reliability implications of the proposed solutions. For a list of projects under PBUT8 (Substation Rebuild), broken down by projects obligated by FEMA, projects active in LUMA's

Long Term Implementation Plan (LTIP), and projects with FAASt numbers canceled as of the date of the filing of this document, please refer to Table 8.

5.4.2 Substation Reliability (PBUT7)

This program will reinforce and upgrade existing system infrastructure to improve reliability, including replacing aging transformers, oil circuit breakers, distribution circuit breakers, other high-voltage equipment, alternating current/direct current (AC/DC) systems, standby generators, relays, remote terminal units (RTUs), and auxiliary systems. It will also include protection and control upgrades and procurement of emergency spares. As discussed above under PBUT8, new transformer standards will provide additional capacity to address load growth and higher penetration of distributed energy resources. Table 14 below includes distribution projects identified under this initiative.

Table 14 Distribution under Substation Reliability Initiative (PBUT7)

Progress FY25	
Distribution Breaker Replacements	8
Transformer Replacements	1
Distribution Relays Replacements	10
Forecast FY26 to FY35*	
Distribution Breaker Replacements	307
Distribution Transformer Replacements	60
Distribution Metal Clad Replacements	7
SCADA RTU Replacements	3
Protection, Automation and Control Upgrades	12
Substation Minor Repairs	22

Additional projects will be evaluated and proposed upon completion of ongoing field assessments and engineering inspections.

5.4.3 Distribution Line Rebuilds (PBUT6)

The Distribution Line Rebuild program focuses on rebuilding distribution feeders with poor reliability performance and those that serve critical power facilities, targeting the worst-performing feeders first. This program will result in significant system improvements in the short term and incremental improvements for the remaining program duration.

This program includes:

- Reconstructing distribution backbones by replacing distribution poles, conductors, and associated equipment with infrastructure that can withstand requisite design wind speeds according to applicable codes and standards and higher capacity conductors.
- Addressing voltage and loading violations identified by planning studies.
- Installing underground cable and tree wiring to improve service reliability and resiliency to critical customers.

Distribution rebuild projects will provide additional benefits to the distribution system over existing distribution feeder infrastructure. Use of structures able to withstand requisite wind speeds will make the feeders more resilient to severe weather conditions, which will aid in overall system restoration and result in reduced impact to customers due to these events. Use of higher rated conductors in the feeder backbones will provide additional capacity for load growth, enable load transfers between feeders, improve voltage regulation by reducing voltage drop, and reduce line losses. All aluminum or copper conductors will be used in feeders located close to the coast to reduce corrosion. Covered conductors will be used in high vegetation areas to help reduce interruptions from vegetation contact. Animal guards will be used to reduce the occurrence of outages caused by wildlife coming into contact with energized equipment. The use of higher capacity conductors and modern voltage regulation devices will also enable additional penetration of distributed generation by providing more capacity and improving feeder voltage regulation.

LUMA grouped feeders into three categories based on historical reliability data, specifically on Customer Minutes Interrupted (CMI). The first category is made up of Worst Reliability Performing feeders, which are those with CMI counts exceeding 3.5 million customer minutes interrupted (3.5M). These feeders represent the worst performing distribution circuits, totaling 83 (7%) out of 1127 load serving feeders. The next category consists of feeders that have CMI counts between 3.5M and 1.5M, and account for 189 feeders (17%). The final category contains feeders with CMI count less than 1.5M, and account for the remaining 855 feeders (76%).

LUMA prioritized addressing the 83 Tier 1 feeders. These are divided into two groups:

- 42 feeders originally submitted as part of an initial group of 151 feeders targeted for rebuild. These feeders are all in the Architecture and Engineering (A&E) design process and were in the pipeline for FEMA review and obligation. These are impacted by the cancellation of FEMA project FAASt numbers and have been placed on hold pending further alignment with PREPA and FEMA.
- 41 remaining feeders are the next recommended group to assign to A&E firms for detailed design development upon available funding and alignment with PREPA and FEMA.

Also prioritized are an additional seven out-of-service feeders that have damaged underground segments targeted to be replaced.

Other feeder rebuild projects that have been paused from the FEMA funding process for higher priority work described above include:

- 64 poor reliability performing feeders that were part of the original 151 feeders submitted as groups for PREB approval and FEMA review, but these have been put on hold to focus execution on the highest priorities.
- 125 additional poor reliability performing feeders with CMI between 1.5 – 3.5M.
- nine additional feeders with damaged underground portions targeted to be rebuilt

Note that these projects that still contribute significantly to reliability challenges on the island may be moved to execution with non-federal capital dollars with sufficient funding made available. Table 15 provides a list of projects currently included in the LTIP and those with FAAST numbers cancelled which will be prioritized to be included in the long-term investment plan.

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Table 15 Distribution Feeder Rebuild Projects - Active and On Hold with Canceled FAAST

Distribution Feeder	Region	Primary Voltage
Distribution Rebuild Projects Proceeding with Active FAAST or Obligation		
8101-03	Arecibo	4.16
3502-02	Caguas	8.32
6601-03	Ponce	7.2
1303-02	San Juan	13.2
1529-15	San Juan	13.2
1620-02	San Juan	13.2
Distribution Rebuild Projects on Hold with FAAST Numbers Canceled by FEMA		
1710-01	Bayamón	13.2
1716-03	Bayamón	13.2
1717-03	Bayamón	13.2
1718-02	Bayamón	13.2
1720-07	Bayamón	13.2
1806-02	Bayamón	13.2
9403-03	Bayamón	4.16
9501-02	Bayamón	8.32
1801-03	Bayamón	13.2
2603-08	Caguas	13.2
3007-03	Caguas	8.32
3006-05	Caguas	13.2
2906-02	Caguas	13.2
3701-03	Caguas	8.32
2402-02	San Juan	13.2
2404-06	San Juan	13.2
6012-02	Mayagüez	13.2
6014-02	Mayagüez	13.2
7011-03	Mayagüez	13.2
6010-01	Mayagüez	4.16
6305-03	Mayagüez	4.16
6306-02	Mayagüez	4.16
6802-04	Mayagüez	13.2
6406-02	Mayagüez	13.2
6603-01	Ponce	13.2
6704-03	Mayagüez	13.2
5602-02	Ponce	13.2
1204-02	San Juan	13.2
1204-04	San Juan	13.2
1204-05	San Juan	13.2

Distribution Feeder	Region	Primary Voltage
1303-01	San Juan	13.2
1303-05	San Juan	13.2
1909-09	Bayamón	13.2
1336-08	San Juan	13.2
7805-13	Mayagüez	13.2
7805-11	Mayagüez	13.2
1115-02*	San Juan	13.2
1115-03*	San Juan	13.2
1115-04*	San Juan	13.2
1117-07*	San Juan	13.2
1117-08*	San Juan	13.2
1424-07*	San Juan	13.2
1424-08*	San Juan	13.2

*Underground feeder rebuild project.

5.4.4 Distribution Pole and Conductor Repair (PBUT30)

This program focuses on minimizing the safety hazards caused by distribution poles, equipment, and conductors that must be repaired or replaced. Major repairs and replacement will be based upon the results of an assessment of the distribution system and an analysis by engineers to schedule the repair or replacement based on the criticality of the pole. Following this process, safety hazards and priority poles will be replaced, along with damaged equipment, conductors, and hardware.

Table 16. Summary of Progress and Targets for Distribution Pole and Conductor Repair (PBUT30)

Progress Through FY25	
Structures Identified for Replacement	6249
Structures Replaced*	4702
Forecast FY26 to FY35	
Fiscal Year	Structures Targeted for Replacement
FY26	2962
FY27	2876
FY28	2612

*Structures replaced as of April 1st, 2025.

5.5 Future Improvement Opportunities Identified under Area Planning Studies

As mentioned above, LUMA has also completed Area Plan studies that assess the adequacy of the capacity of each substation and associated feeders to serve current and forecasted load in their respective service areas under both normal operation (supplying the load normally fed by the substation or feeder) and contingencies (upon loss of a feeder or substation). These studies identify capacity and resiliency issues and other issues such as thermal or voltage violations. Once these violations are identified, mitigations are proposed to address the issues. The summary of Area Plan studies executed, number of planning areas, and substations and feeders assessed in each area can be found in Table 17.

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Table 17 Area Plan Studies Status as of September 2025

Region	Planning Areas	Substations	Feeders
Arecibo	8	39	119
Bayamón	9	45	153
Caguas	10	48	146
Mayaguez	12	52	166
Ponce	12	54	170
San Juan	20	97	373
Total	71	335	1127

Area Plan studies identify potential solutions to address potential issues. The proposed mitigations to address normalization (mitigating voltage and thermal violations), reliability and N-1 contingencies are summarized below.

Area Plan Normalization Recommendations – Area Plan studies identify voltage or loading violations and propose measures to mitigate against potential violations identified. These mitigation measures may include

- Phase balancing- redistributing load among the three phases of a feeder
- Reconductoring – upgrading to a higher conductor along sections of a feeder
- Load transfer/feeder reconfigurations – reconfiguring a feeder or transferring out load to adjacent feeders
- Capacitor Bank Installation/Removal or Upgrade – installing a new capacitor bank, upgrading or removing existing banks to address voltage issues
- Voltage Regulator Installation/upgrades – installation of voltage regulators to improve voltage profile of a feeder; upgrades to existing units to account for higher loads
- Voltage Conversion – upgrading existing infrastructure to 13.2 kV
- Line Extension – extension of new feeder segments to allow feeder reconfiguration and lower customer count

Table 18 below summarizes normalization recommendations proposed in Area Plan studies.

Table 18 Potential Normalization Mitigations Identified Under Area Plan Studies

Recommended Mitigations	Arecibo	Bayamon	Caguas	Mayaguez	Ponce	San Juan	Grand Total
Capacitor Addition	34	26	18	113	73	12	276
Capacitor Removal	-	2	-	30	11	1	44
Capacitor Upgrade	5	5	2	20	10	11	53
Controlled Capacitor Addition	21	9	31	43	33	21	158

Overhead Feeder Extension (ft)	80,535	11,629	64,320	74,910	115,634	73,036	420,064
Overhead Reconductoring (ft)	307,872	449,637	230,106	273,918	529,127	210,803	2,001,463
Overhead/Underground Extension (ft)	28,300	28,923	3,425	66,651	106,008	67,037	300,344
Overhead/Underground Reconductor (ft)	286,157	82,054	18,415	587,886	219,967	581,776	1,776,255
Phase Change	184	152	169	678	148	114	1,445
Switch Addition	4	8	13	63	4	8	100
Switching/Load Transfer	27	36	26	90	49	77	305
Underground Feeder Extension (ft)	50	26,700	-	4,500	6,100	1,816	39,166
Underground Reconductoring (ft)	1,439	22,862	1,737	10,285	5,759	469,421	511,503
Voltage Converter Addition	5	17	2	8	9	13	54
Voltage Regulator Addition	45	8	6	42	35	6	142

Feeder Reliability Recommendations – Area Plan studies identified potential improvements to feeder reliability, consisting mainly of new fuse additions, removal of mainline fuses or replacing them with three-phase reclosers, replacing large lateral tap fuses with single-phase reclosers, and faulted circuit indicators (FCI) installation. Table 19 below gives a summary of the proposed reliability recommendations by region.

Table 19 Proposed Reliability Recommendations by Region.

Recommended Mitigation	Arecibo	Bayamon	Caguas	Mayaguez	Ponce	San Juan	Grand Total
1ph Recloser Addition	1,096	514	1,085	1,543	1,480	727	6,445
3ph Recloser Addition	178	255	221	302	294	281	1,531
FCI Addition	375	328	436	497	544	477	2,657
Fuse Addition	3,049	2,271	2,738	4,614	4,941	2,265	19,878
Fuse Removal	1,370	445	2,037	1,367	1,662	672	7,553
Fuse Upgrade	406	-	513	219	471	1	1,610
Switch Addition	106	41	213	193	195	73	821
Switch Upgrade	24	22	48	47	37	24	202
Switchgear Upgrade	-	12	-	3	-	-	15

Contingency (N-1) Recommendations – Area Plan studies conducted transformer and feeder contingency analysis, assuming complete failure of an asset (feeder breaker or substation transformer) necessitating full load transfer to adjacent assets. Any lack of transfer capacity was identified and possible solutions proposed. These include the creation of new feeder ties by installation of new switches or tie reclosers, extension of feeder segments to create new ties, transformer upgrades or new distribution substations. These recommendations will greatly improve the distribution system's ability to withstand natural disasters by increasing its ability to transfer out loads upon the loss of an asset (substation or feeder).

Table 20 below summarizes the proposed N-1 recommendations by Region.

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Table 20 Identified N-1 Opportunities by Region

Recommended Mitigation	Arecibo	Bayamon	Caguas	Mayaguez	Ponce	San Juan	Grand Total
3ph Recloser Addition	61	222	75	142	110	555	1,165
Capacitor Upgrade	-	-	-	4	2	-	6
Overhead Feeder Extension	8,805	46,934	28,255	382,802	28,299	28,253	523,348
Overhead Reconductoring	-	-	-	2,048	-	4,619	6,667
Overhead/Underground Extension		2,875	620	22,613	1,961	3,681	31,750
Overhead/Underground Reconductoring	-	-	-	-	-	385,583	385,583
Switch Addition	50	40	15	87	78	82	352
Switching/Load Transfer	-	-	-	4	2	1	7
Underground Feeder Extension		790		6,600		10	7,400
Underground Reconductoring	-	-	-	N/A		34,155	34,155
Voltage Converter Addition	3	9	1	67	17	6	103
Voltage Regulator Addition	1	-	10	32	10	1	54

The mitigations identified as part of the Area Planning studies are incorporated, where applicable, as part of substation or feeder rebuild projects identified above. LUMA will also evaluate additional funding options to carry out projects aimed at incorporating these recommendations including Non-Federal Customer Funding.

Also, these mitigations presented above are meant to illustrate the scope of potential opportunities to improve the distribution system and will be updated as additional planning studies are carried out and pending more detailed engineering reviews.

6.0 Distributed Energy Resources and Advanced Grid Technologies

6.1 Evolution of DERs in Puerto Rico

Distributed Energy Resources (DER) in this report refers to residential and commercial scale resources such as rooftop solar which are interconnected to the customer premises. These are typically connected at distribution voltage but may also be connected to customers served directly at sub-transmission voltage. Across the industry, DER penetration is increasing as the equipment cost of solar panels and battery energy storage systems decreases,[1] electricity rates increase[2], and customers seek solutions to manage costs, clean energy, energy independence and resilience.

Since the passage of Act 114 in 2007, which established the first legal framework for Net Energy Metering (NEM) in Puerto Rico, DER adoption has seen tremendous growth. Puerto Rico's Energy Regulations 8915 and 8916 govern the interconnection of DER, have outlined the processes for DERs to connect at the distribution and sub-transmission. At the distribution level, systems up to 1 MW are permitted, while at the transmission level, systems up to 5 MW are permitted. Act No.17 of 2019 introduced a requirement for the utility to automatically approve any DER system below 25kW. This law accelerated DER adoption by expediting the NEM process and customers rapidly began installing rooftop PV systems, coupled with energy storage as shown in Figure 7.

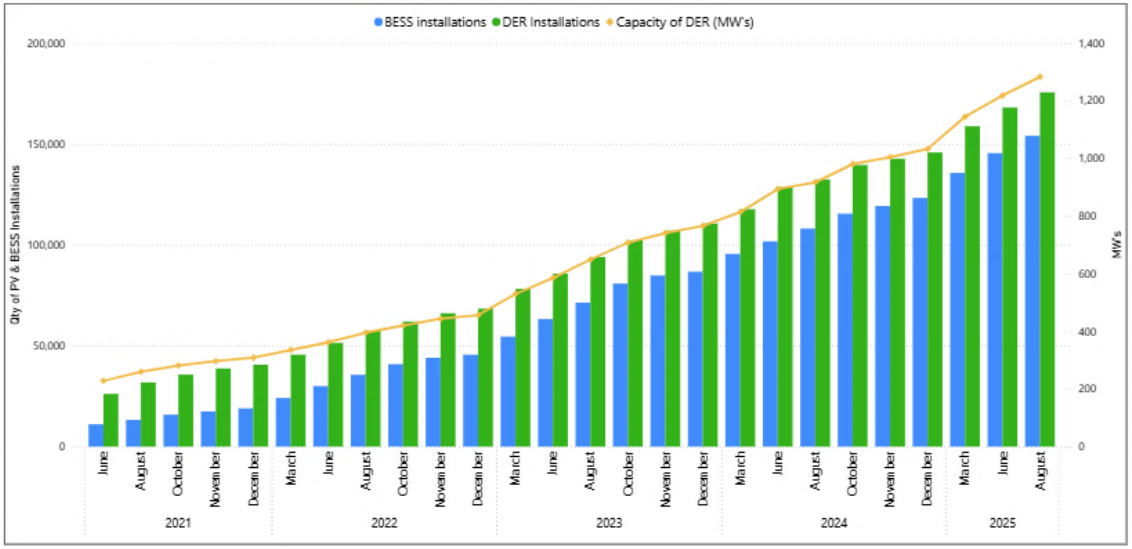
In June 2021, LUMA Energy commenced operations of Puerto Rico's T&D system. LUMA centralized and streamlined the DER Interconnection process which significantly reduced activation times. As shown in Figure 7, at commencement LUMA inherited approximately 26,000 customers with distributed PV systems and has enabled the connection of over 175,000 active customer accounts with a distributed PV system with an installed capacity of 1,282 MWs, and over 153,000 Battery Energy Storage Systems (BESS) representing 850MW and 2,600MWh of energy storage capacity as of August 2025. The graph shows only residential and small commercial systems installed. Battery energy storage systems attachment rate is currently 88%. LUMA understands that customers are investing in batteries to improve daily reliability experience, and for the resilience to keep the lights on during grid outages or after major events such as hurricanes

[1]NREL U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023
[2] Energy Information Administration, "Residential electricity bills could increase slightly this summer," June 23, 2025 [https://www.eia.gov/todayinenergy/detail.php?id=65544]

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Figure 7 Proportion of BESS vs DER (PV) Installations and DER (PV) Aggregate Capacity 2021 to 2025

Year	Month	BESS installations	DER Installations	Capacity of DER (MW's)
2025	August	153,943	175,481	1,283
2025	June	145,379	167,986	1,218
2025	March	135,551	158,684	1,144
2024	December	123,176	145,715	1,032
2024	November	119,192	142,625	1,004
2024	October	115,408	139,468	980
2024	August	108,008	132,295	916
2024	June	101,642	128,554	893
2024	March	95,439	117,573	813
2023	December	86,640	110,496	765
2023	November	84,765	107,000	741
2023	October	80,752	102,174	707
2023	August	71,302	93,890	649
2023	June	63,236	85,661	585
2023	March	54,484	78,096	529
2022	December	45,492	68,335	456
2022	November	43,984	66,041	443
2022	October	40,815	61,908	420
2022	August	35,586	57,385	395
2022	June	29,936	51,330	362
2022	March	24,060	45,509	335
2021	December	18,903	40,541	308
2021	November	17,379	38,676	296
2021	October	15,816	35,675	281
2021	August	13,198	31,762	260
2021	June	11,029	26,077	228



6.2 Safety and Equipment Risks from DER Interconnections on Puerto Rico's Grid

LUMA supports the continued development of clean energy technologies, individual customer reliability improvement, and individual customer energy independence and resilience. However, as the grid operator, LUMA has an obligation to ensure utility worker and public safety, grid reliability for all customers, and affordable electricity rates for all customers. The current regulatory framework presents significant challenges to balancing customer choice, safety, grid performance and reliability, and energy affordability.

First, Act 17-2019 requires automatic connection of customer distributed PV systems below 25 kW, which account for 99 percent of customer interconnections, and over 20 MW each month. The primary challenge presented is that developers are connecting customer solar PV and battery energy storage without prior utility review of feeder health and performance to recommend necessary safety, reliability, or equipment rating upgrades before the DER interconnects. To LUMA's knowledge, Puerto Rico is the only jurisdiction that allows for uncontrolled DER interconnection with no evaluation whatsoever—this allows incredibly unsafe and dangerous conditions to exist on the grid, risking human life, equipment and property damage. Only after the system is interconnected can the utility retroactively assess impact of the interconnection. Studies continue to identify an accelerated find rate that new interconnections are exacerbating DG related thermal violations of transformers or circuit conductors, DG related high voltage violations due to solar PV injection at the customer premise for which the grid was not designed grid performance or safety issue.

LUMA has responded by proactively studying the impact of aggregated DER connected on individual circuits and focusing on those circuits where aggregated connected PV capacity (in MW) exceeds 15 % of the feeder's maximum demand (in MW). As of August 2025, the average penetration rate on LUMA distribution circuits is 49%, which is considered very high when compared to other states and territories. These studies continue to identify required network upgrades for equipment that is already overloaded by the DER at the time the study occurs (after the DER is already connected and injecting power to the grid). The most common network upgrades required include service transformer upgrades, main circuit voltage regulation technology, and converting capacitor banks to ones with remote on/off capability. Thermal overloads have also been identified and are expected to accelerate as unconstrained distributed PV adoption continues in the near term.

As of October 2025, LUMA had studied 771 feeders at least once, covering over 123,000 DER installations. Results show that 660 feeders out of 771 (or 85% of feeders studied) experience a thermal or voltage violation. The summarized issues directly attributable to DER are shown on Table 21:

Table 21 Summary of DER Violations

Summary of DER Violations Identified Across 771 Feeders	
Voltage Issues	285
Thermal Issues (including service transformers)	638
Total Violations	923

6.3 DER Tools Available to Developers and Customers

To support developers and customers in making informed decisions about DER installations, LUMA has developed DER penetration maps Figure 8 and Incremental Hosting Capacity Maps (IHCM) (Figure 9). These tools provide valuable information on network conditions and potential upgrades that may be required before a customer connects their DER. These resources are essential for balancing the growth of DERs with the stability and reliability of the island's energy grid.

Figure 8: DER Penetration Map

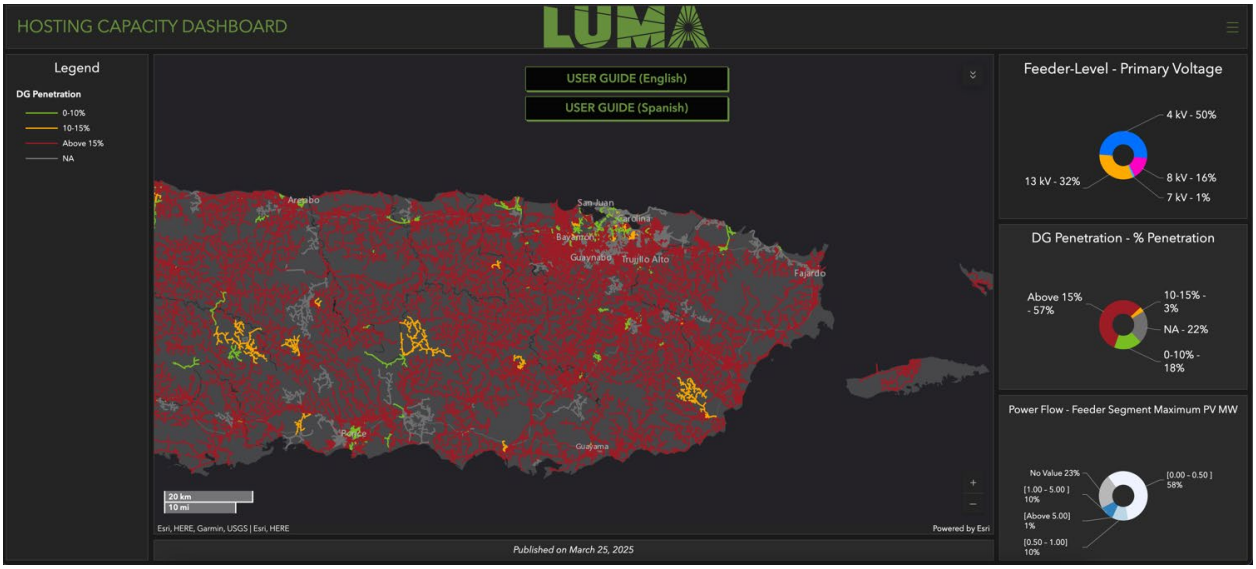
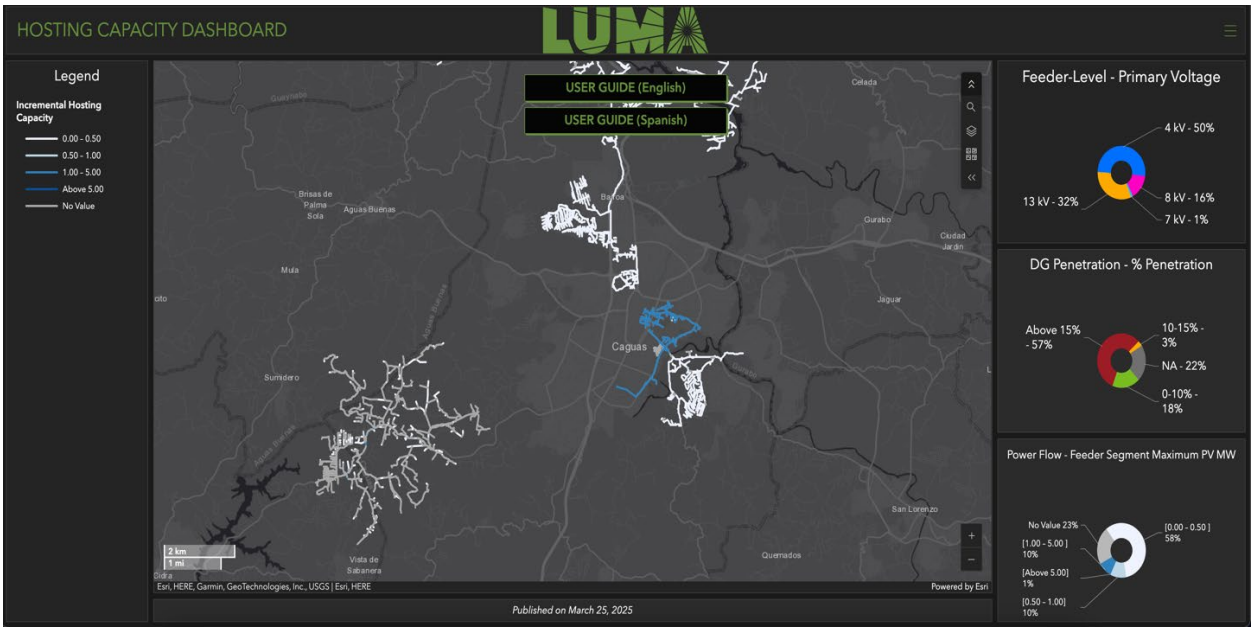


Figure 9: Incremental Hosting Capacity Map



6.4 Implementing Smart Inverter Settings Improves Impacts from DER Integration

Continuing to integrate high volumes of rooftop solar PV on Puerto Rico's distribution grid requires urgent corrective action by regulators. One such urgent action is to implement proposed Smart Inverter Settings as proposed by LUMA to mitigate some, but not all, of the feeder violations that occur today. Note that performance criteria violations related to PV induced voltage rise can be mitigated with settings like Volt-Var and Volt-Watt. However, other performance violations like service transformer overloads require the developers to upgrade the size of the transformer. More costly investments like feeder-level voltage regulators and conductor upgrade to resolve thermal overloads are beginning to appear and will become more prevalent over the coming years at the current pace of customer DER adoption. Note that LUMA's understanding of current laws assigns the financial responsibility of all grid improvements that correspond to DER interconnection to the developer.

LUMA's proposed adoption of Smart Inverter Settings leverages the technology standard, IEEE 1547-2018, to define those settings that help all customers across Puerto Rico. This helps by limiting the voltage rise when the PV is injecting by keeping the customer voltage within acceptable range, which avoids neighboring customers from experiencing the high voltage that would occur without the settings enabled. These settings were developed through collaborative stakeholder engagement, but were informed by LUMA operational data, detailed engineering analysis using Synergi for feeder studies and simulations. Note that LUMA first filed a proposed list of settings in August 2024, and the Energy Bureau's November 2024 Order initiated the Smart Inverter Working Group (SIWG) collaborative stakeholder process. LUMA has proposed revisions to Smart Inverter Settings submitted in June 2025 which balance between stakeholder input, technical feasibility, and regulatory compliance. As of October 10 ,2025, LUMA is still awaiting a final decision to adopt the June's 2025 recommended Smart Inverter Settings.

6.4.1 Illustrative Examples Supporting Smart Inverter Settings (Volt-Var and Volt-Watt)

Smart inverter functionalities such as Volt-Var and Volt-Watt have demonstrated ability to mitigate the voltage violations caused by PV injection and two-way power flows on distribution circuits. Technical and engineering analysis and multiple simulation studies of high-penetration feeders revealed that without these settings many circuit sections are experiencing daily high voltage violations. When the revised smart inverter settings were applied, the number of circuit sections with high voltage violations reduced significantly or were eliminated. This evidence underscores that smart inverter settings mitigate existing grid issues but also can enable increased DER integration without requiring additional infrastructure upgrades. By implementing smart inverter settings on DER that is already deployed today, we both mitigate existing violations and cost-effectively enable higher interconnection volumes.

The subsequent illustration shows the impact of Smart Inverter Settings of an actual feeder in San Juan with approximately 1,674 kW (or 1.67MW) of aggregated nameplate PV installed capacity. Four (4) scenarios were run to understand how the feeder performs, see Table 22:

- No PV injection (baseline performance – feeder designed to operate at this level),
- PV injecting but with no Smart Inverter Settings enabled (actual condition which customers experience today),
- PV injecting with Smart Inverter settings enabled (Volt/VAR only)
- PV injecting with Smart Inverter settings enabled (Volt/VAR and Volt/Watt).

Table 22 Scenarios of Feeder 02 Demonstrating Impact of Smart Inverter Settings

Case	DERs Aggregated Capacity (kW)	V max (120V base)	V min (120V base)	Sections with Violations	Available Hosting Capacity (kW)
No solar PV Injecting (benchmark)	0	126.0	120.0	0 of 677	1315
Solar PV Injecting Without Settings Enabled (actual conditions)	1674	127.57	124.96	218 of 677	0
Solar PV Injecting With Volt-Var Settings Enabled (simulated)	1674	126.12	124.0	28 of 677	30
Solar PV Injecting With Volt-Var & Volt-Watt Settings (simulated)	1607	126.0	124.0	0 of 677	100

In the first scenario, all solar PV were turned off to baseline what feeder performance would be without PV injection. Note that this scenario is precisely how loading and power flows would occur with the circuit as designed and built. The intent of this scenario is to identify if any pre-existing voltage or thermal violations occur when no PV injection is present. The results showed that no violations exist when PV are not injecting (this would be the case before the PV was installed).

In the second scenario, all existing PV is injecting with no Smart Inverter (Volt/Var or Volt/Watt) settings enabled to simulate what customers experience today. The results are shown in Figure 10 Approximately 218 of 677 (or 1/3) of the circuit sections experience some type of voltage violation, which would happen today.

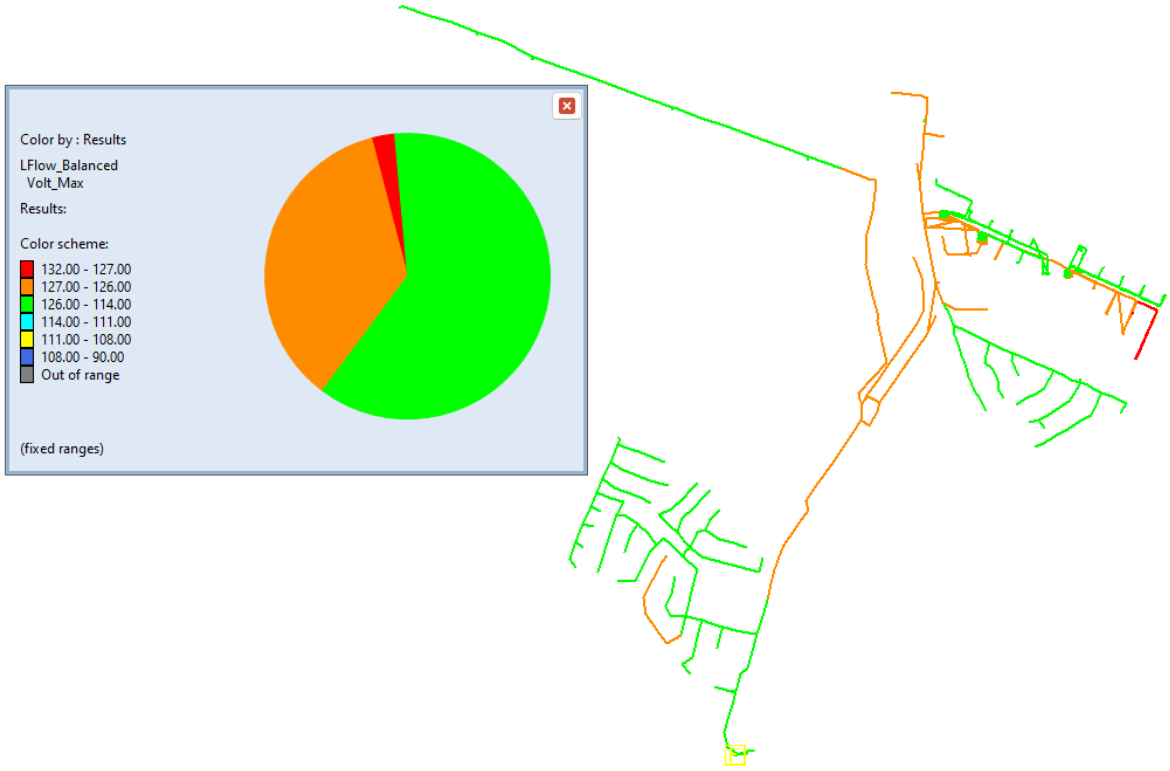
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In the third scenario, all existing PV is injecting, but this time with Smart Inverter (Volt/Var) settings enabled. The results are shown in Figure 11. Approximately 28 of 677 (or 4%) of sections would experience some type of voltage violation. This demonstrates that Volt/VAR can solve many of the problems with PV-induced high voltage, and help the circuit return to its designed configuration parameters, but not all issues can be resolved.

The fourth scenario has all existing PV injecting, but this time with Smart Inverter Volt/Var and Volt/Watt settings enabled. The results are shown in Figure 12. All violations are mitigated with both settings activated, therefore returning the circuit to its design configuration parameters before customers began installing PV.

This case shows how the coordinated use of both Volt/Var and Volt/Watt functions can mitigate voltage violations triggered by DERs in this feeder. The use of efficient power control modes corrects the voltage profile along the feeder, preserves the operability of the system and how they can allow more PV to interconnect without upgrades (since voltage is all within acceptable limits in scenario 4). This may also potentially delay voltage mitigation related upgrades that would otherwise be required if these control modes are not utilized.

Figure 10 Feeder 02 Voltage Profile with No Smart Inverter Settings Enabled Showing Significant Violations



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Figure 11 Feeder 02 Voltage Profile Illustrating Smart Inverter Settings (Volt-Var) Some Violations Resolved

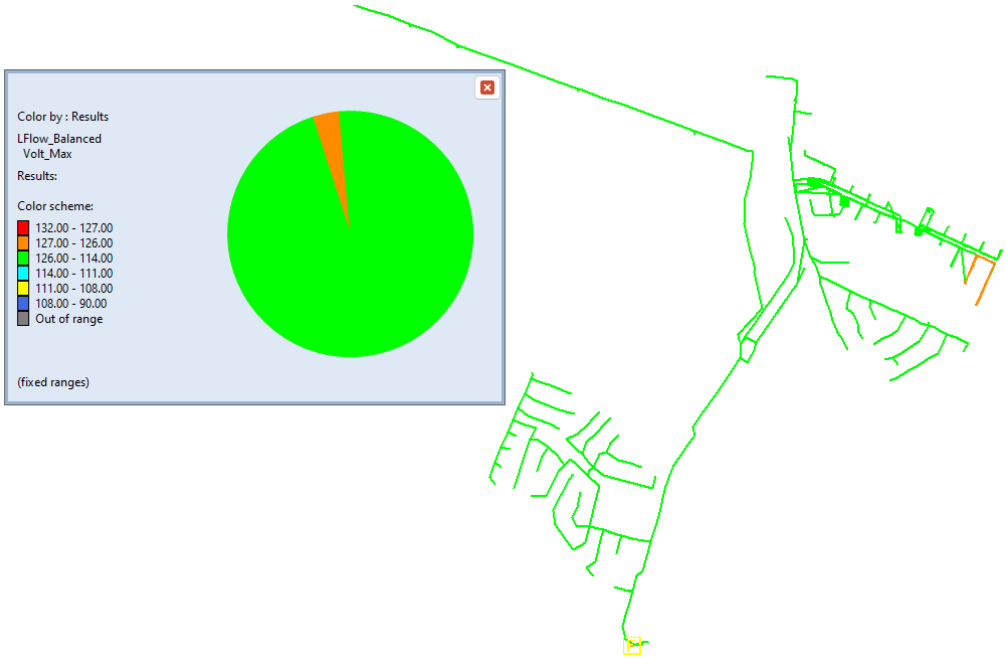
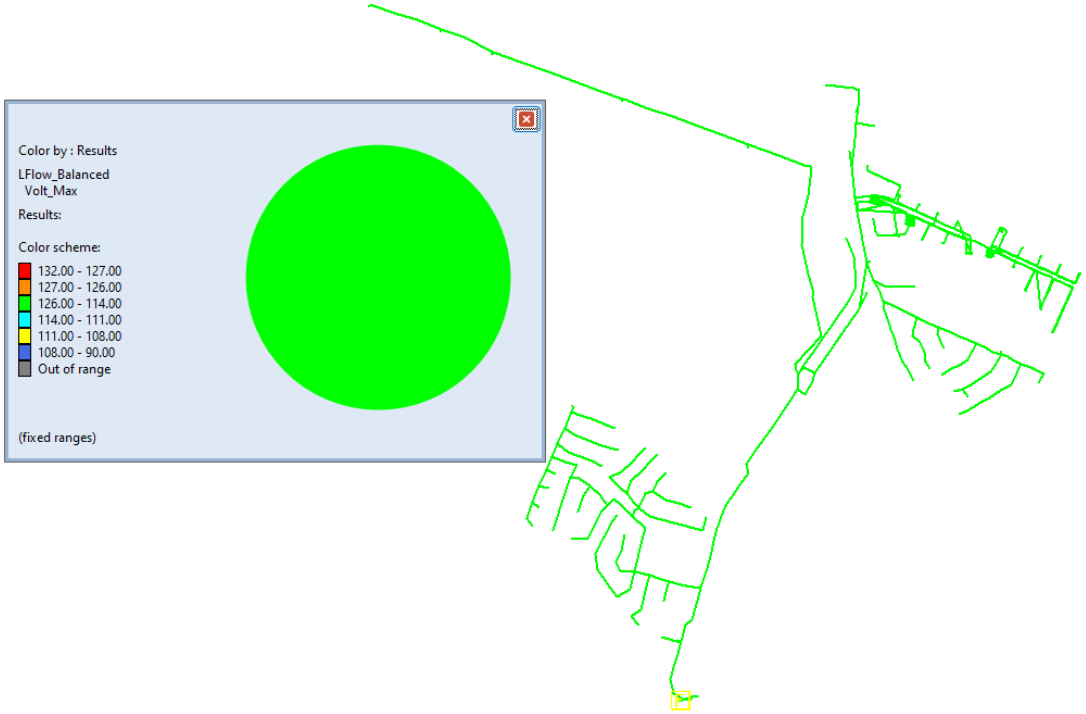


Figure 12 Feeder 02 Voltage Profile with Smart Inverter Settings (Volt-Var &Volt-Watt) All Violations Resolved



6.5 Existing Advanced Grid Technologies Description

LUMA is progressing its advanced grid technologies by deploying automated switchgear and fault sensors across distribution feeders to bolster reliability. Additionally, LUMA will implement automatic switching distribution feeder automation systems to further enhance reliability. The included switchgear consists of three-phase and single-phase reclosers. Communicating fault sensors have been deployed to provide fault location information to the control center to improve service restoration times for customers. The scope of the program consists of the installation of communication ready smart reclosers with microprocessor-based controllers for remote monitoring, and control.

The program scope includes communication devices for the reclosers and all associated networking upgrades to provide Supervisory Control and Data Acquisition (SCADA) operators remote control and visibility of the recloser status. Fleet Management Software is included to provide stakeholders visibility of operations to improve fault analysis and response times to feeder outage restoration. The scope includes upgrading outdated protection devices at the feeder head in the substations to modern digital devices that can be used in conjunction with the reclosers.

Additionally, the program includes the installation of communicating Fault Circuit Indicators in strategic locations to provide more granularity to operators as to the location of faults on a feeder to speed up restoration actions. The program includes the communication integration required, including networking devices to communicate the fault locations to SCADA and Outage Management Systems. LUMA has deployed 3,716 Fault Circuit Indicators (FCI) during the previous fiscal years, and is planning to install 1,000 additional FCI during fiscal years 2025 to 2029. LUMA is expecting to receive a purchase of 8,000 FCI for the next four years as shown in the Table 23.

Table 23 FCI Devices Installed

Actual/ Targeted FCI Installed	2022	2023	2024	2025	2026	2027	2028	2029
Period Start	7/1/21	7/1/22	7/1/23	7/1/24	7/1/25	7/1/26	7/1/27	7/1/28
Period End	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27	6/30/28	6/30/29
Actual FCI Devices Installed	93	990	1,371	1,205	57*-	-	-	-
Targeted FCI Devices Installed	N/A	1,000	1,000	1,000	1,000	1,000	1,000	1,000

The optimal locations for the installations of the three phase reclosers (T&D), fault circuit indicators and single phase reclosers are identified as part of studies to improve reliability of the feeders. The location of reclosers will ensure the required coordination of substation circuit breakers, reclosers and fuses. The intent of the deployment of the reclosers is to minimize permanent[3] outages for temporary faults on the distribution feeders. The engineering philosophy and standards are being established to ensure long term continuation of feeder protection and control designs.

The program includes the automation of distribution feeders and 38 kV lines to further improve feeder reliability. Grid automatic switching schemes will leverage the reclosers to tie two feeders through an open tie recloser. The intent of the feeder automation schemes is to provide feeder segments between

[3] Permanent outages refer to those that require repair before re-energizing.

reclosers with redundant power sources. The feeder automation schemes will automatically isolate faulted feeder segments and restore power to healthy feeder segments from an alternate power source. This includes the replacement of outdated protection devices at the 38 kV lines headend including engineering and construction. The new protection devices will provide required functionality to better coordinate with the reclosers.

LUMA is also deploying advanced sensor capabilities, both to improve the reliability and resilience of the energy system, as well as to support the integration of renewable generation sources. One key capability to do so, which has been identified by agencies including the Department of Energy and the US National Labs, consists of Phasor Measurement Units (PMUs), an electronic device capable of measuring voltage and current waveforms and calculating their magnitudes and phase angles (phasors), frequency, and power quantities, and stream these monitoring variables to a central unit like the network control center. PMUs collect data synchronized in a µsec (microsecond) level, which is crucial in the root cause analysis of large events as the team can truly identify the sequence of happenings. PMUs report their measurements to the central unit at 30 or 60 frames/sec, which is an order of magnitude faster than SCADA system and enable system operators to monitor the dynamic security of the system and be proactive against the events to minimize their impacts rather than just being reactive.

LUMA is deploying this capability in a number of ways. As part of projects that include substation rebuilds, LUMA is deploying technologies such as digital relays or recloser controllers that have integrated PMU capability into their products. Where prudent, LUMA is also deploying independent advanced sensors, including PMUs and optical sensors, in substations allowing for visibility across the transmission system. LUMA is also looking to deploy PMUs to prioritize distribution feeders, including as part of the Vieques and Culebra microgrid project, which will provide incremental value including 1) situational awareness beyond the current SCADA information, 2) forensic analysis to diagnose issues that led to events, 3) power quality monitoring, and 4) fault detection in combination with other measuring devices to help pinpoint the problematic sections.

Within Vieques and Culebra, the distribution PMUs will work alongside transmission PMUs and other communicating devices in the implementation of microgrids in the island municipalities. The data from the PMUs are going to be used by the microgrid controller to make the right decision for transitioning between the islanded, microgrid cluster or grid-connected operation modes.

Further information on the deployment of reclosers, faulted circuit indicators and other related devices is included below in sections describing the Distribution Automation and Distribution Grid Reliability programs.

6.5.1 Distribution Automation (PBUT4)

This program involves deploying automated switchgear and fault sensors on distribution feeders to improve grid reliability. It will take place as part of LUMA's efforts to enhance system performance through remote operations, fault detection, and faster service restoration, utilizing advanced communication tools and system analysis. The program will involve LUMA's engineering team, field operators, and the Operations team for deployment, integration, testing, and maintenance. This program includes:

- Installation of three-phase and single-phase reclosers
- Deployment of automatic switching distribution feeder automation systems

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- Deployment of communicating fault sensors

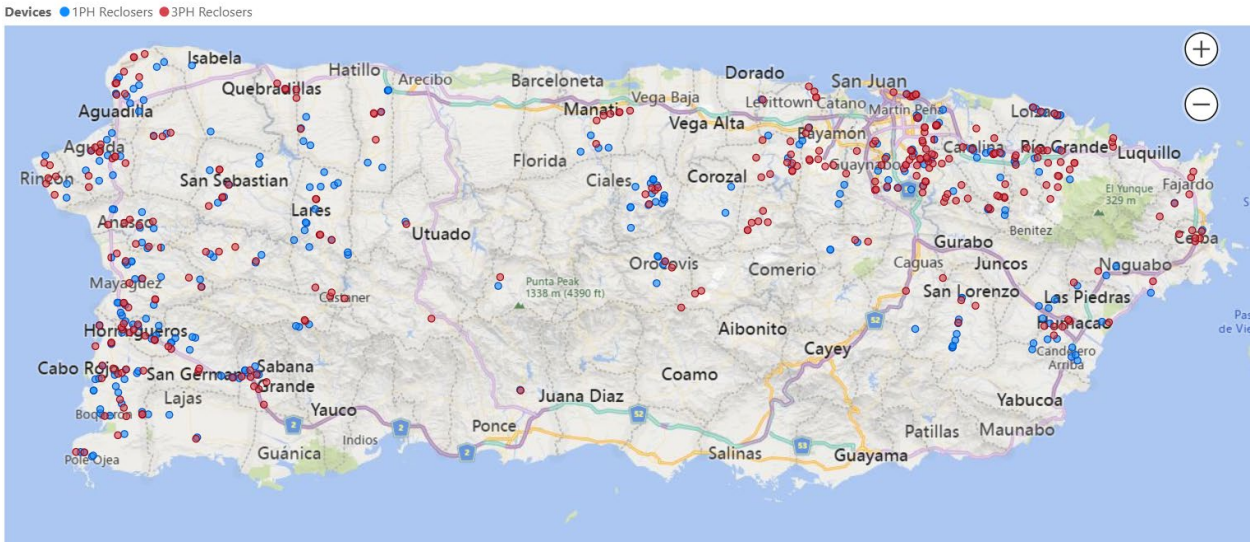
As of September 2, 2025, a total of 308 three phase reclosers and 674 single-phase reclosers have been installed under this initiative, impacting 156 distribution feeders. In addition, 963 fuse cutouts have also been installed.

Table 24 below shows a summary of the progress and forecast under this initiative.

Table 24 Progress and Forecast Under Distribution Automation Initiative

Progress Through FY25					
Three-phase Reclosers Installed			308		
Single-phase Reclosers Installed			674		
Unit Type	**FY26**	**FY27**	**FY28**	**FY29 - FY35**	**Total**
1-Phase Reclosers Installed	746	2,000	2,145	8,435	13,326
3-Phase Reclosers Installed	219	500	539	2,117	3,375
CFCi Installed	668	1,500	1,630	6,390	10,188

Figure 13: Progress under PBUT4 Distribution Automation



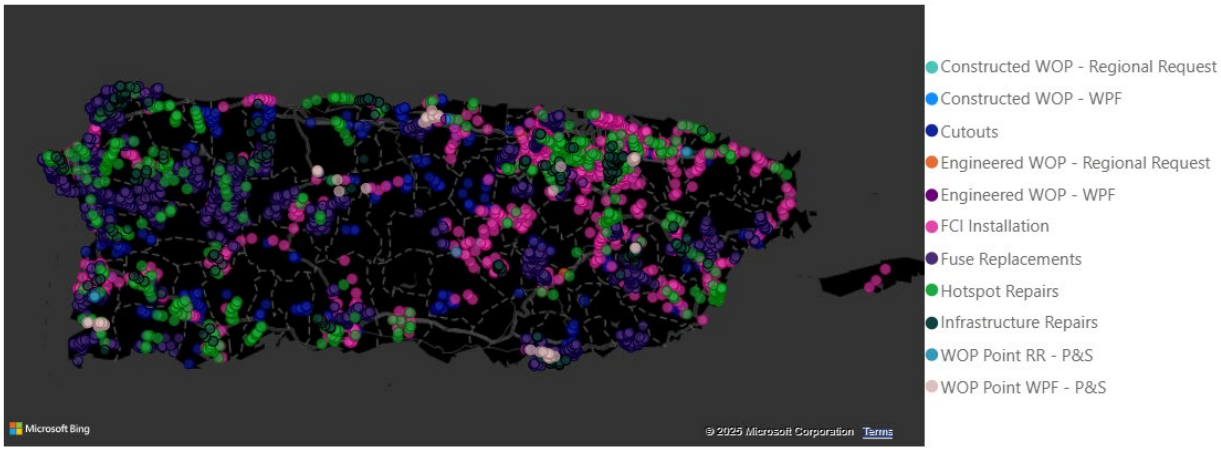
6.5.2 Distribution Grid Reliability (PBUT39)

This program focuses on reducing outages, improving response times, and ensuring the delivery of safe and reliable electricity to customers. The program has three main drivers:

- Addressing Worst Performing Feeders based on historical reliability metrics, with efforts including infrared and visual inspections, outage history assessments, and capital improvement projects to minimize outage frequency and enhance customer satisfaction.
- Regional Reliability Improvements targeting localized reliability concerns identified by district operations team, will prioritize strengthening feeder backbones and laterals, implementing protection measures, and aligning enhancements with regional priorities to optimize overall grid performance.
- Reliability System Upgrade Initiative which integrates Fault Current Indicators (FCIs) and fuse coordination to improve fault detection, expedite restoration efforts, and provide better segmentation of clients during faults.

As of September 2, 2025, this program had installed 3,716 non-communicating Fault Current Indicators, verified the ratings of 4,863 fused cutouts, carried out 775 hotspot repairs and an additional 249 infrastructure repairs.

Figure 14 Progress under PBUT39 Distribution Grid Reliability



6.5.3 Distribution Streetlighting

This program deals with upgrading and replacing distribution streetlights that are a physical safety hazard scheduled for repair or replacement based on their criticality. Along with increasing the number of distribution streetlights in service, this process will include light-emitting diode (LED) replacements and geographic information system (GIS) data entry of all streetlights. See Table 25.

Table 25 Progress and Forecast under Distribution Streetlighting Program

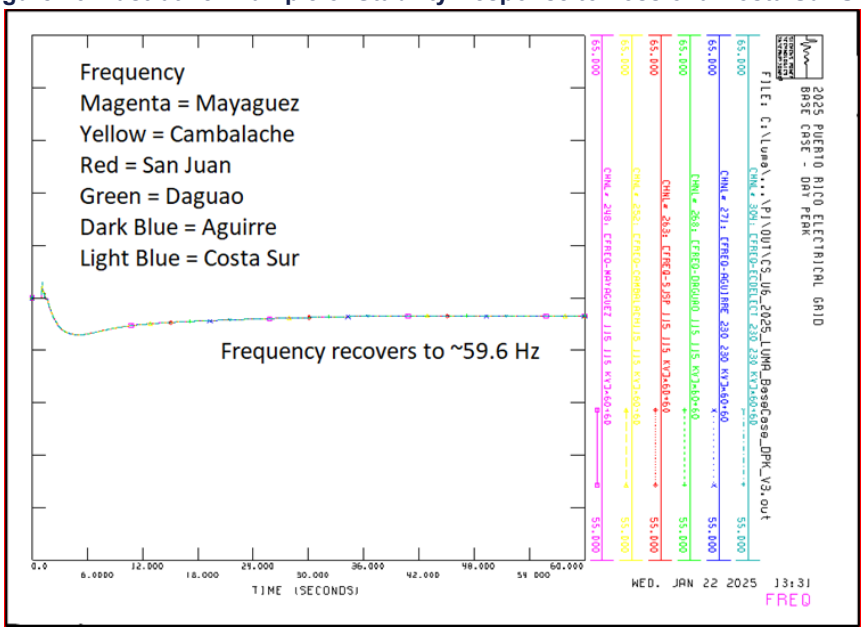
Progress Through FY25				
Assessment	462,970			
Phase 1 - Repl. Components	147,091			
Phase 2 - Repl. Secondary Poles without TPA	5,769			
Phase 3 - Repl. Secondary Poles with TPA & Octagonal	6,005			
Forecast FY26 to FY35				
	FY26	**FY27**	**FY28-35**	**Total**
Phase 1 - Number of Luminaries Replaced	16,091	0	0	16,091
Phae 2 - Replace Streetlight Pole without TPA	6,179	2,070	0	8,249
Phase 3 - Replace Streetlight Pole with TPA & Octagonal	6,774	13,314	5335	25,423

7.0 System Stability Analysis

In accordance with PREB's System Stabilization Plan requirements, LUMA has requested generators to independently verify their equipment design specifications and parameters and their "as-operated" configuration settings which include turbine-governor models, over/under excitation controls and parameters, automatic voltage regulator configuration and settings, and relevant generator dynamic model technical data. A requested deliverable includes producing validated test-reports that document these parameters as designed and as-operated, as well as the PSS®E dynamic model representation of the generator.

To ensure a comprehensive assessment of the system's dynamic performance, the analysis included in the annual TPL Assessment covers a range of operating scenarios, specifically Day Peak and Night Peak conditions for the near-term study year. By analyzing both peak scenarios, the studies capture the possible differences in system stability and performance of the various contingency scenarios outlined in Table 28. The worst-case generator contingency simulated was loss of Costa Sur Unit. Figure 15 illustrates the stable system response to loss of a Costa Sur unit, and settling frequency of 59.6 Hz.

Figure 15 Illustrative Example of Stability Response to Loss of a Costa Sur Unit



In absence of a verified dynamic model for each plant, verification of dynamic model performance in PSS®E is common after events involving generator trips or frequency excursions. As an illustrative example, a unit trip at Palo Seco that triggered under-frequency load-shedding was compared in PSS®E against actual recorded system frequency response data. As can be observed from Figure 16, the PSS®E model quite accurately predicts the system frequency response to the disturbance:

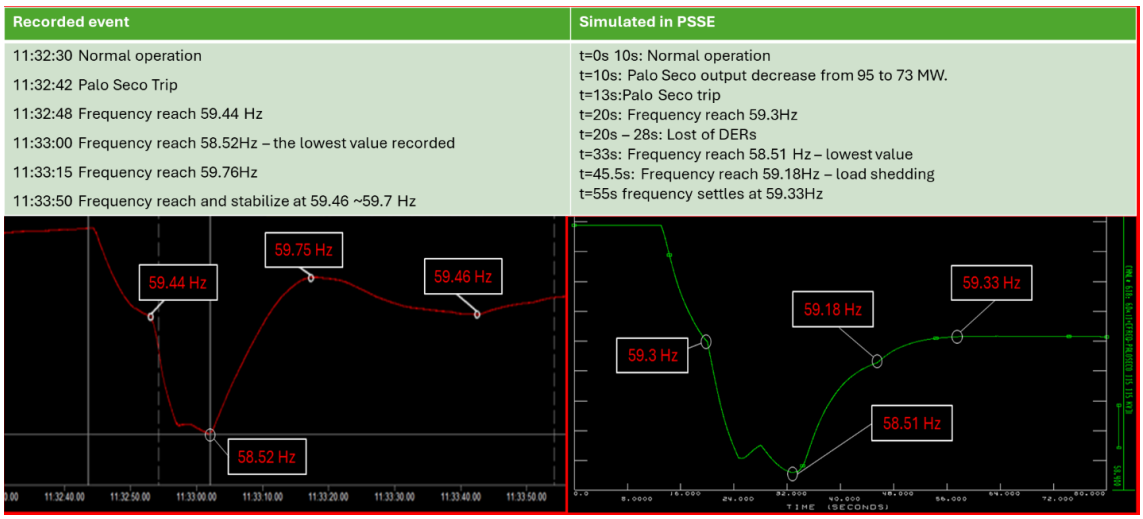
- The minimum frequency was simulated within a 0.01Hz difference between actual and PSS®E simulated values, which represents an error of less than 0.016%.

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- Distributed Energy Resources are noted to trip during both actual recorded data and simulated PSS®e result.
- Automatic load shedding is verified in both actual recorded data and simulated PSS®e result.
- Although the recovery frequency in actual response was higher than that in PSS®e, the simulation provides conservative estimate of system recovery after an event within 0.3% error.

This result indicates that the PSS®e models do need verified generator models and settings to drive accuracy and produce more representative system response to frequency events, but that existing dynamic models are representative and analysis with this model may be conservative.

Figure 16 System Frequency Response to Generation Loss Event



Investigating further, specific units which have been tested and verified in the past were observed to respond quite differently in the actual data when compared to the modeled response in PSS®E. When the model parameters where adjusted to match more closely to the actual response recorded, a much closer match was observed in initial settling frequency. This further highlights the importance of modeling all generators based on “as-operated” conditions since complex interactions between multiple generators are required to drive accuracy of total system frequency response. An illustrative example is shown in Figure 17.

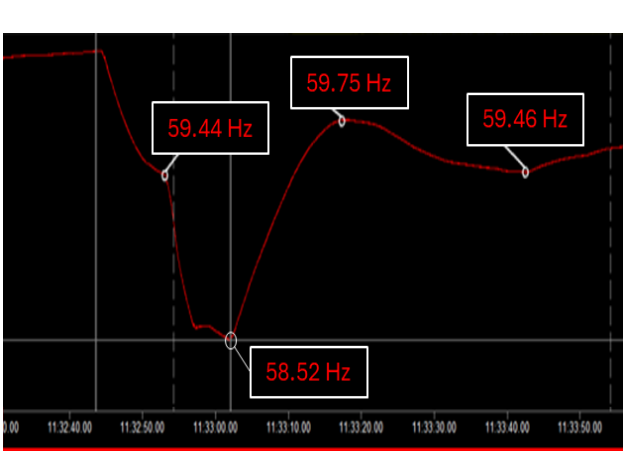
Puerto Rico’s Under Frequency Load Shedding (UFLS) scheme provides an essential service to stabilize the system by quickly balancing load (using load sheds) when a loss of generation event occurs. Relays at distribution circuit breakers, on sub-transmission lines and in substations are programmed to drop loads when frequency declines past a certain pre-defined threshold. Investigating the value of the UFLS scheme, a simple scenario illustrates what happens if UFLS is not available to help the system recover quickly. Figure 17 illustrates the continued system frequency decline after a generation loss event if UFLS does not respond. Conversely, the UFLS activates to arrest the frequency decline immediately after an event and allows frequency to recover; importantly the difference in the immediate frequency decline is over 0.5Hz, and the recovery period shows over a 2Hz difference.

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This result also highlights the urgency for resources that provide fast frequency response, are based on robust generator dynamic model industry practices, and that help the grid by avoiding UFLS which relies on customer interruptions to balance system loads and resources.

Figure 17 Comparing Frequency Response After Adjusting a Single Generator Parameter

Recorded Data	PSS®E Simulation



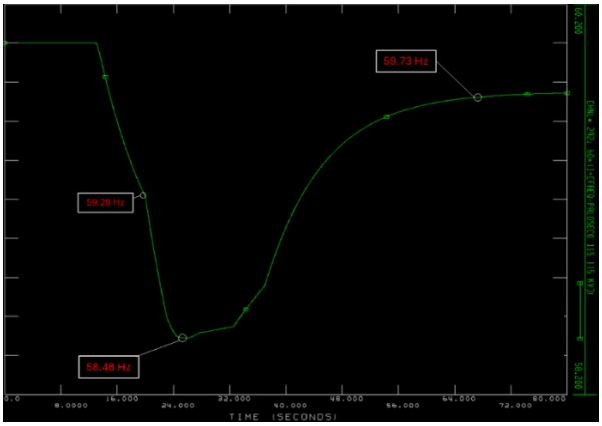
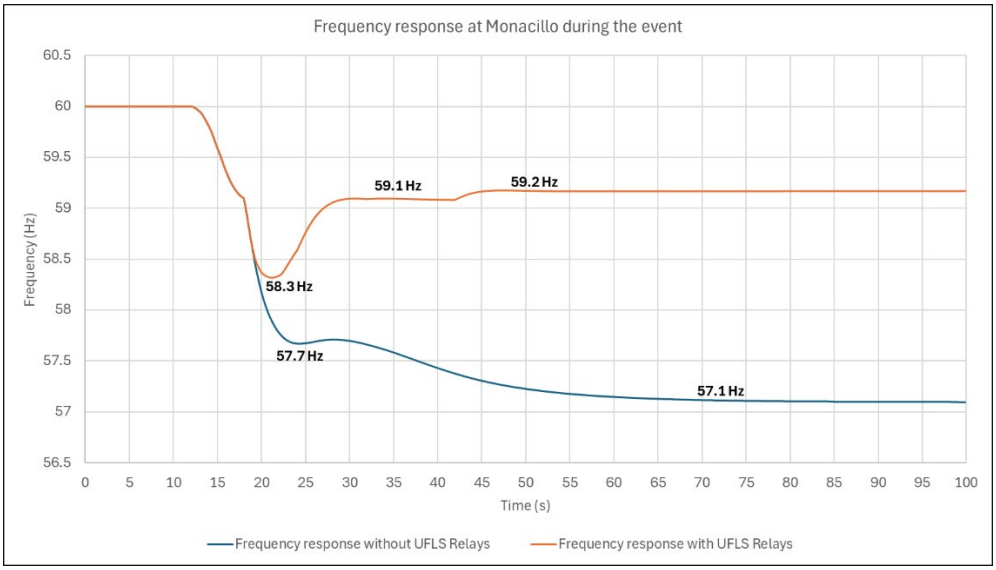


Figure 18: Under Frequency Load Shedding Impact on System Frequency Recovery



8.0 Thermal and Voltage Reliability

8.1 Transmission System Thermal and Voltage Reliability Issues

Due to the sensitive nature of the grid performance data discussed here, the following tables, Table 26 and Table 27 identify detailed and specific vulnerabilities of the transmission system which could be exploited and are therefore to be treated as considered CEII.

As part of the TPL Assessment, LUMA performed contingency analysis according to the Transmission Planning Criteria discussed in Appendix B of this report. Thermal and voltage violations were identified and were widespread across the island across multiple contingencies.

Table 26 illustrates the N-1 thermal violations identified for the 2025 model year. Note that these violations exist on the system as it presently operates, and is a major contributor to the poor reliability performance of the Puerto Rico transmission system. Note also that these contingency results are exacerbated by a select group of transmission lines and substation transformers that remain out of service, but that are being restored under the System Priority Stabilization Plan. Note also that the list of transmission lines that will require capacity upgrades are those identified in column 2 in the table.

Table 27 shows voltage issues identified for the Year 1 2025 Day Peak case in the TPL Assessment.

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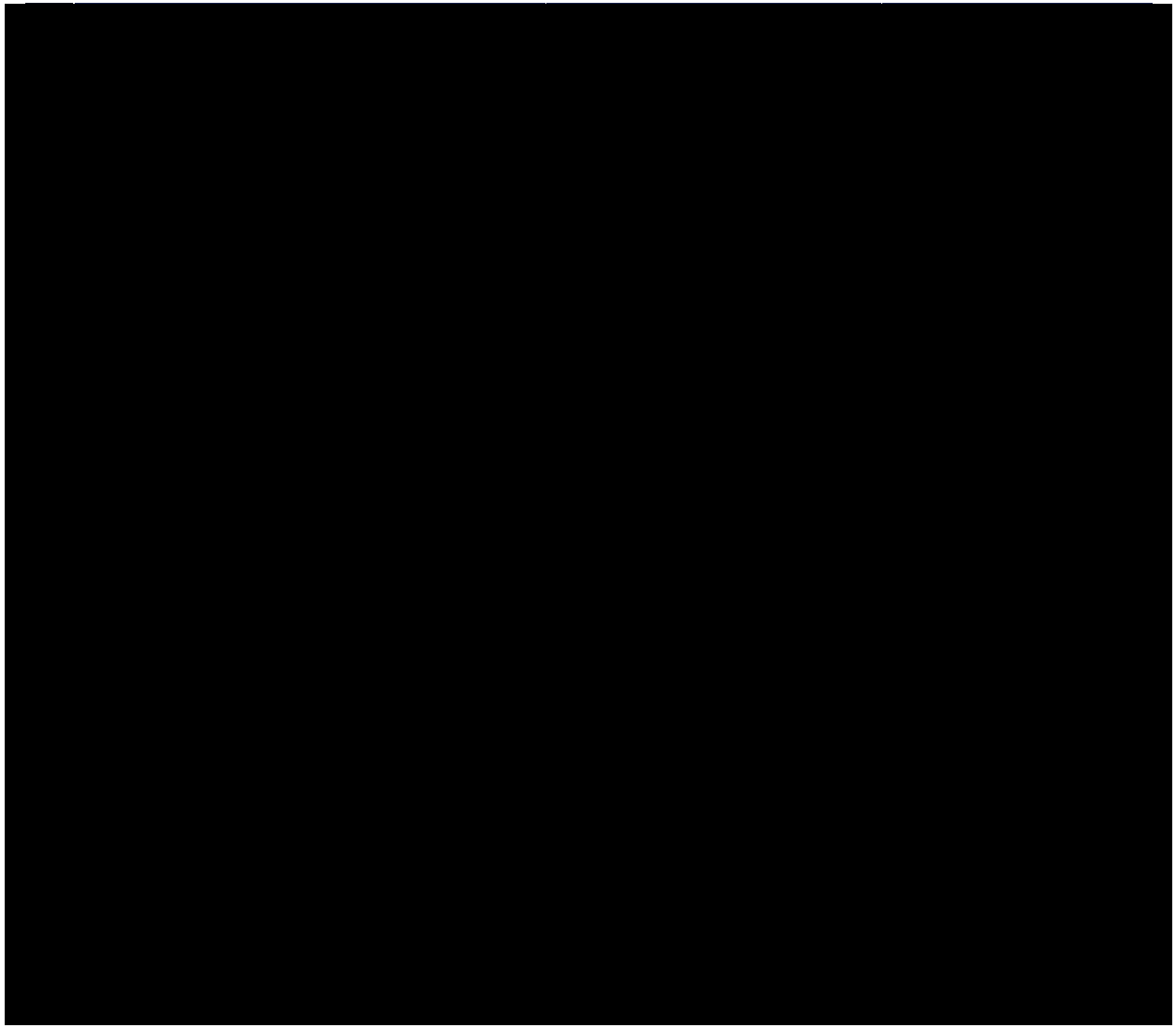
Table 26 (CEII) 2025 Critical Performance Criteria Violations: N-1 Thermal Overloads



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8.1.1 Voltage Violations

Table 27 (CEII) 2025 Critical Performance Criteria Violations: N-1 Voltage Violations



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	If this element fails	This bus has voltage problems	Worst Low Voltage Violation (% of rated voltage)
13	Both L-37200 & L-50500 TRIP	AÑASCO 115KV BUS	0.89
14	VIADUCTO TC STUCK TIE BREAKER 115KV BUS	ISLA GRANDE 115KV BUS	0.89
		ISLA GRANDE 115KV BUS 2	
15	JOBOS TC 38KV BUS 1 FAULT	MAUNABO TC 38 KV BUS	0.62
16	CAYEY TC 115 BUS 1 FAULT	CAYEY TC 38 KV BUS	0.75
17	HUMACAO TC 38 KV BUS 1 FAULT	JOBOS TC 38 KV BUS	0.79

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A.1 Puerto Rico Electric Transmission System

Figure 19: Puerto Rico Electric Transmission System



A.2 Transmission Planning Criteria

Executive Summary

This Transmission Planning Criteria document establishes how LUMA will meet the criteria described in the Transmission Planning Standards document. At LUMA, we strive to plan the BES system in Puerto Rico such that the customers of the island will experience reliable, secure, and resilient power delivery. LUMA has established a transmission planning department that will assist operations by modeling complicated contingencies and known system conditions that create potentially disastrous conditions for its customers. These conditions will be systematically analyzed and corrected by either capital enhancement projects or special protection systems to automatically respond to the condition and restore as much of the system as possible. The operations department will receive this direction from transmission planning to be ready if such a condition should occur. As additional conditions become evident transmission planning will continue until all issues are resolved or known that the system will operate to the maximum reliability for the customers.

Transmission Planning Criteria

The LUMA's transmission planning standard has been established using TPL-001-05 developed[4] and published publicly by NERC and adjusted to the uniqueness of Puerto Rico and its customers.

Storm Response

LUMA will develop an emergency response based on the worst-case and high-impact scenarios identified by the transmission planning criteria. If a storm is pending, transmission planning and the transmission operation department will be staffed such that any issues be thwarted. This will include engineering groups from Transmission planning occupying emergency operational facilities to assist in the restoration of complicated contingency analysis.

Transmission System Planning Performance

The purpose of this document is to facilitate LUMA's near-term and long-term transmission planning for normal and abnormal conditions. This document applies to all transmission planning studies conducted within the LUMA footprint.

Circuit Ratings

Normal circuit rating should mean that the circuit can maintain a current up to the limit indefinitely.

The emergency rating should mean that the circuit can only maintain this current for a defined period, not to exceed 24 hours. This rating assumes an acceptable loss of equipment life.

Load Shed Rating should mean that the system will be required to shed load to maintain the circuit rating in less than 15 minutes.

Maintenance Condition Criteria

[4] See: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf

Maintain a steady state voltage of 95 to 105 % for system normal configuration. Circuits should not be loaded beyond their Normal rating.

Contingency Criteria

- Steady-state voltages at all applicable Bulk-Electric System (BES) buses[5] should stay within each of the following limits:
    - 95 to 105 % of nominal for P0 event (system normal pre-contingency event power flow).
    - 90 to 110 % of nominal for P1-P7 events (post-contingency event power flow).
- Post-contingency steady-state voltage deviation at each applicable BES bus serving load should not exceed 8 % for P1 events.
- Following fault clearing, the voltage should recover to 80 % of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.
- Following fault clearing and voltage recovery above 80 %, the voltage at each applicable BES bus serving load should neither dip below 70 % of pre-contingency voltage for more than 30 cycles nor remain below 80 % of pre-contingency voltage for more than two seconds, for all P1 through P7 events.
- For Contingencies without a fault, voltage dips at each applicable BES bus serving load should neither dip below 70 % of pre-contingency voltage for more than 30 cycles nor remain below 80 % of pre-contingency voltage for more than two seconds.
- All oscillations that do not show positive damping within 30 seconds after the start of the studied event should be deemed unstable.
- When a post-contingency analysis results in steady-state facility loading that is either more than a known BES facility trip setting or exceeds 125 % of the highest seasonal facility rating for the BES facility studied, the facility should be taken out of service for cascading study.
- The Transmission Planning department will develop post-contingency switching plans to maintain the circuit flow or the voltage magnitude within acceptable ranges and provide guidance to the transmission operations department for training and preparedness if the situation should occur.

Voltage Stability Criteria

For load areas, all P0-P1 events should demonstrate a positive reactive power margin at a minimum of 105 %of the forecasted peak load.

For load areas, all P2-P7 events should demonstrate a positive reactive power margin at a minimum of 102.5 % of the forecasted peak load.

Power Quality Criteria

[5] 38, 115 and 230 kV.

The LUMA system should be operated as a balanced three-phase system with minimal flicker and minimal harmonic distortion. Measured data will identify any issues that may need correcting. IEEE std. 519 and IEEE Std. 1453 should be used to determine acceptable limits for harmonics and flicker.

A.3 Transmission Planning Standard: Puerto Rico Transmission Planning Standard (based on NERC-TPL-004-1)

Executive Summary

This Transmission Planning Standard document defines how LUMA will plan the BES system in Puerto Rico such that the customers of the island will experience reliable, secure and resilient electric power delivery. LUMA has established a transmission planning department that will assist operations by modeling complicated contingencies and known system conditions. These conditions will be systematically analyzed and corrected by either capital enhancement projects, or corrective action plans. As additional conditions become evident transmission planning will continue until all issues are resolved or known that the system will operate to the maximum reliability for the customers.

Annual Assessment

A planning assessment of the transmission system is to be performed on an annual basis to ensure compliance with the transmission planning criteria for both near-term and long-term transmission planning horizons. The planning assessment must use up-to-date system models.

For cascading that can be caused by the occurrence of extreme contingencies, an evaluation of possible pre-contingency actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the contingency(s) will be conducted.

Near-Term Steady-State Assessment

The planning assessment should assess Year One and Year Five. The assessment for any other year in between should be performed when the system undergoes a major change in generation resource or transmission topology or the steady state, planning assessment should assess the following operating conditions of the study year(s):

System peak load for Year One and Year Five

- System off-peak load for Year one and Year five
- Sensitivity cases of the system peak load for Year one and Year five and the system off-peak load for Year one. To accomplish this, the sensitivity analysis will vary one or more of the following conditions by enough to stress the system within a range of credible conditions that demonstrate a measurable change in system response:
    - Real and reactive forecasted load
    - Expected transfers between transmission zones
    - Expected in-service dates of new or modified transmission facilities
    - Reactive resource capability
    - Generation additions, retirements, or other dispatch scenarios

Generation or transmission facilities outages planned in the near-term planning horizon should be assessed for P0 and P1 categories identified in Table 28.

The loss of major transmission equipment with a duration of more than one year should be assessed for P0, P1, and P2 categories identified in Table 28.

The steady-state assessment should be performed at minimum for the P0, P1, P2, P3, P6 and P7 categories identified in Table 28.

Extreme contingencies in Table 28 that are expected to produce more severe system impacts should be identified and assessed. In no case can the planned Non-Consequential Load Loss exceed 5 MW non-critical or 1 MW critical load in the San Juan planning area, and 10 MW in other planning areas.

Near-Term Stability Assessment (115 and 230 kV)

The stability assessment should assess the following operating conditions of the study year(s):

- System peak load for Year one and Year five
- System off-peak load for Year one and Year five
- Sensitivity cases of System peak load for Year one and Year five, and System off-peak load for Year one. To accomplish this, the sensitivity analysis can vary one or more of the following conditions by enough to stress the system within a range of credible conditions that demonstrate a measurable change in system response:
    - Load level, Load forecast, or dynamic Load model assumptions
    - Expected transfers between transmission zones
    - Expected in-service dates of new or modified Transmission Facilities
    - Reactive resource capability
    - Generation additions, retirements, or other dispatch scenarios.

Generation or transmission facilities outages planned in the near-term planning horizon should be assessed for the P1 category identified in Table 28.

The loss of major transmission equipment with a duration of more than one year should be assessed for P1 and P2 categories identified in Table 28.

The stability assessment should be performed at a minimum for the P1, P2, P3, P6 and P7 categories identified in Table 28.

Extreme contingencies in Table 28 that are expected to produce more severe system impacts should be identified and assessed.

Short Circuit Study

The short circuit analysis should be performed to determine whether circuit breakers have the necessary interrupting capability for faults that they will be expected to interrupt using the system short circuit model with any planned generation and transmission facilities in service. A short circuit strength study also needs to be performed to assess the ability of the grid to integrate the existing and planned resources including inverter-based resources.

Long-Term Steady-State Assessment

The steady-state assessment should assess the peak load condition of Year 10 at minimum for the P0, P1, P2, P3, P6 and P7 categories identified in Table 38.

Extreme contingencies in Table 28 1 that are expected to produce more severe system impacts should be identified and assessed. No cascading should be allowed.

Long-Term Stability Assessment (115 and 230 kV)

The stability assessment should assess the impact of system changes. Generator, Load, and Transmission changes will be evaluated every year for compliance with two criteria: 1. To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-fault conditions and, 2. To maintain the coordination of Protection Systems installed to detect and isolate Faults on BES Elements, such that those Protection Systems operate in the intended sequence during Faults.

Corrective Action Plans

For planning contingencies shown in Table 28 1, if the analysis indicates an inability of the system to meet the performance requirements in Table 28 1, the planning assessment should include a corrective action plan(s) addressing how the performance requirements will be met.

Corrective action plan(s) need to be developed to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

If the short circuit current interrupting duty on circuit breakers exceeds their equipment rating, the planning assessment should include a corrective action plan to address the equipment rating violations.

Use of past studies

Past studies can be used to support the current planning assessment if past studies are not more than five calendar years old and no material changes have occurred to the system from the time the past studies were performed.

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Table 28 LUMA Transmission Planning Contingencies

Category	Initial Condition	Contingency	Fault Type	Voltage	Non- Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	38KV and above	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø	38KV and above	No
P2 Single Contingency	Normal System	1. Opening of a line w/o a fault	N/A	100KV and above	No
		2. Bus Section Fault 3. Internal Breaker Fault (non-bus-tie) 4. Internal Breaker Fault (bus tie)	3Ø		
P3 Multiple Contingency	Loss of generator unit followed by System adjustments	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø	38KV and above	No
P4 Multiple Contingency (Fault plus stuck breaker)	Normal System	Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section 6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	100KV and above	Yes[1]
P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section	3Ø	100KV and above	Yes[1]
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System adjustments 1. Transmission Circuit	Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	3Ø	38KV and above	Yes[1]

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Category	Initial Condition	Contingency	Fault Type	Voltage	Non- Consequential Load Loss Allowed
	2. Transformer 3. Shunt Device				
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on a common structure	3Ø	100KV and above	Yes[1]

The planned Non-Consequential Load Loss should not exceed:

- 5 MW non-critical or 1 MW critical load in the San Juan planning area, and
- W in other planning areas.

A.4 Distribution Planning Criteria

A.5 LUMA Distribution Planning Criteria

Introduction

This document describes the distribution system planning criteria to be used in LUMA's planning of the PREPA system. It defines the performance criteria incorporating LUMA's standards. This document will be reviewed and updated regularly to improve LUMA's planning process and introduce industry lessons, practices, and advancements following applicable requirements.[6]

Definitions

Normal rating: The rating, as defined by the equipment nameplate, specifies the level of electrical loading that a system, facility, or element can support while handling the load cycles without the loss of equipment life. Loading up to the normal level will not result in an accelerated reduction of service life.

Emergency Rating: The rating specifies the level of electrical loading or output, usually expressed in appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes an acceptable loss of equipment life or other physical or safety limitations for the equipment involved. If loading is expected to exceed the emergency rating, corrective or remedial action, including load shedding, may be required.

Distribution System: The distribution system is used to provide and operate the wires and the equipment between the transmission system and the end-use customer.

Transmission System: The system used by the transmission service provider (TSP) to the transmission customer to move energy from a point of receipt to a point of delivery.

Sub-Transmission Voltage: For LUMA energy, the sub-transmission voltage is at 38 kV.

Primary Distribution System: The primary distribution system is a network that includes wires, poles, substations, and other equipment from the low-voltage side of the distribution substation up to the distribution transformer at the customer location.

Secondary Distribution System: The secondary distribution system is the final stage of delivering electricity to individual customers. It is the part of the electric power distribution network that carries electric energy from distribution transformers to electricity meters of end customers.

Native Load: The end-use customers that the utility is obligated to serve.

Distribution Power Transformer: Distribution power transformers (i.e., distribution transformers) are used at the primary distribution voltages.

Service Transformer: A service transformer is a type of transformer that steps down the voltage used in the distribution lines to the level used by the customer (normally 110 V or 220 V).

Load Tap Changer (LTC): The LTC or ULTC is a type of transformer that can adjust the voltage ratio of the transformer under load without interrupting the power supply.

[6] "Applicable requirements" refers to PR Act 17-2019 Section 1.15 and any subsequent amending law and policy.

Voltage Regulator: In a power distribution system, voltage regulators try to maintain the downstream system voltages within a defined range.

Capacitor Bank: Capacitor banks are capacitors connected in a series and/or parallel to provide a certain amount of reactive power to the point of connection. In the distribution system, they are primarily used to improve the power factor.

Fault Current: The current delivered at a given point of the system during a short-circuit condition.

Hosting Capacity (HC): Hosting capacity in a distribution system refers to the amount of distributed photovoltaic (DPV) generation that can be added to the distribution system before control changes or system upgrades are required to safely and reliably integrate additional DPV systems. Examples of evaluation criteria are over-voltage, over-loading, reverse power flow at the feeder's head or at a certain location, voltage fluctuation due to intermittent change of distributed energy resource (DER) generation, etc. The feeder loading is a calculation input. LUMA uses two primary methods to evaluate the hosting capacity of a feeder: incremental hosting capacity and stochastic hosting capacity.

Incremental Hosting Capacity: This incremental hosting capacity method cumulatively adds photovoltaic (PV) generation to a line segment in order to determine the maximum amount of DPV generation that can be added without violating any of the given criteria.

Stochastic Hosting Capacity: The stochastic hosting capacity method randomly adds PV generation of a predetermined size to different locations in a study feeder until a violation is encountered. The cumulative PV value in the line segment is recorded. The same PV allocation method is repeated a predetermined number of times. Finally, a statistical value (minimum or average) is chosen from the results of all the runs to represent the line segment's stochastic hosting capacity.

Planning Areas: Planning areas are geographical and/or electric regions within a larger distribution system. A larger distribution system is divided into multiple regions to increase the ease of analysis and assessment of whether the distribution system is capable of serving existing and future power demand under normal conditions and during contingencies.

Distribution system planning involves the process of analyzing the electric distribution system to assess whether it is capable of serving existing and future power demand under normal conditions and during contingencies. A complex distribution system is divided into multiple planning areas (e.g., by geographical and/or electrical region) for ease of analysis.

Non-Wire Alternative (NWA): NWA refers to any electrical grid investment that aims to defer or eliminate the need to construct or upgrade components of a distribution and/or transmission system.

Solar PV: In a distribution system, solar PVs can generate electricity for on-site consumption and interconnect with the electric utility system. Solar PV and storage can be located in front of the meter or behind the meter.

Distributed Energy Resource (DER): DERs are small, geographically dispersed generation resources—such as solar or combined heat and power (CHP)—installed and operated on the distribution system at voltage levels below the typical bulk power system levels of 100 kV. DERs provide electricity generation, storage, or other energy services and are typically connected to the lower-voltage distribution grid for local use.

Distributed Generation (DG): DG, also known as on-site generation or decentralized generation, refers to electricity production by small-scale grid-connected energy systems installed close to where the electricity is used.

Power Factor (PF): The power factor is the ratio of the real power absorbed by the load to the apparent power flowing in the circuit. PF can range from 0 to 1. A higher number means a better use of power.

Harmonic Distortion: Harmonic distortion describes when the voltage and current waves in the power line deviate from their ideal sinusoidal waveform.

Application

This distribution system planning criteria document is intended to guide system planners in developing and reviewing projects to resolve system deficiencies and maintain system integrity, including upgrading and building new substations and distribution feeders. The distribution system planning criteria will be applied to those parts of the electric system that LUMA operates between the transmission source side of the distribution substation transformers and the distribution service transformers. This guide defines the criteria for

System Overview

LUMA's service territory includes the main island of Puerto Rico and two outlying islands of Vieques and Culebra. The distribution system serves customers at five nominal primary voltage levels: 4.16 kV, 4.8 kV, 7.2 kV, 8.32 kV, and 13.2 kV. All distribution substations are served by 115 kV or 38 kV sources.

Fundamental Design Principles

1. Proper regulation of distribution voltage:

    a. The voltage will be considered properly regulated when the voltage at the utility's service points, as installed for each customer, conforms to RUS 1724D-114 and ANSI C84.1. The voltage on a 120 V base should be maintained, after regulation, between 126 V and 114 V under normal conditions and between 127 V and 110 V under emergency conditions.

2. Loading capability:

    a. The distribution system will be designed to not exceed applicable ratings. The applicable loading capacity of a facility will be the appropriate capacity, normal or emergency, approved for use. A facility's normal or emergency rating will be derived from all components associated with the facility and governed by the most restrictive elements' limits.

    b. The normal capacity represents the maximum designed load and adheres to all equipment's normal ratings.

3. The distribution system will be planned to operate without any facility exceeding its normal rating and within acceptable voltage limits at expected load for weather conditions with a 90% probability that load will be at, or under that value, also referred to as 90/10 conditions. In the rare event that the load exceeds the 90/10 forecast, it is expected to be within the emergency rating. In the rare event that the load exceeds the 90/10 forecast, it is expected to be within the emergency rating.

a. The distribution system will be developed to comply with required reliability standards[7] without any facility exceeding its emergency capacity under contingency conditions after any needed reconfiguration.

b. The distribution system will be planned to operate at 90/10 forecasted load levels and planned reliability levels for any of the following unscheduled contingencies:

   i. The loss of a single distribution substation transformer or its supply line at any distribution substation.

   ii. The interruption of any single distribution feeder circuit breaker.

   iii. The loss of a single transmission line.[8]

c. Under certain contingencies, the loss of a particular distribution system facility will result in a load loss. This load loss extent and duration should be minimized. For example, load loss can result from faults such as the following:

   i. Bus fault.

   ii. Radial feeder fault.

   iii. Failure of a distribution circuit breaker to operate properly (i.e., distribution bus lockout).

   iv. Faults occurring during scheduled maintenance (i.e., one transformer at a distribution substation is out for maintenance, and the remaining transformer or supply circuit fails).

Equipment Selection

The system must be planned to utilize standard equipment to the maximum extent practicable. This practice facilitates multiple values streams that include, but are not limited to allowing for optimal inventory and spare equipment management, emergency equipment sourcing and management, improving reliability since failed equipment can be quickly removed and replaced, and accelerating storm restoration since standard equipment can be available and replaced expediently.

Guiding Principles

Background

The distribution system planning criteria document is intended to guide distribution planners when planning the system. It also defines the parameters to consider when initiating a project to reconfigure, extend, or build new distribution feeders and reconfigure, modify, or build new substation infrastructure.

During distribution planning, the total load, total direct and indirect connected customer counts, and resiliency requirements of the area, including critical customers in the known area, should be considered. The load forecast for the area should consider energy efficiency, distributed generation, battery storage, and advanced load management schemes like demand management, conservation voltage reduction (CVR), etc.

Initial and Ultimate Requirements

[7] PR Act 17 2019 s 1.4 & RUS BULLETIN 1730A-119

[8] Contingency plans for single transmission fault impacts should be maintained while design deficiencies persist that do not allow for full-service restoration through normal switching and operation.

System planning incorporates short- and long-range plans[9] to accommodate the forecasted load with proper delivery voltages. This may include 1) system reconfiguration, 2) load transfers, 3) upgrades, and 4) the addition of line equipment such as capacitors and voltage regulators, substation transformers, and 5) new substations or distribution feeders.

The short-range plan supports adequate and reliable electrical service. This plan will describe and justify the short-term changes to the distribution system. Part of the short-range plan is to explain the need for system improvements to meet the design criteria (voltage limits, thermal loading limits, and reliability levels). The short-range plan can be used as a reference for annual construction budgets and schedules. The long-range plan identifies the requirements of a substation for the current load and future loads, including providing the necessary accommodations for renewable energy integration, such as future PV, electric vehicle (EV) charging stations, and load electrification. Where feasible and cost-effective, NWAs should be considered in place of typical distribution upgrades.

During the initial solution's development, distribution planners will specify the capacity needed for a new substation, the ultimate number of feeders, and the approximate location based on the load to be served. This practice secures space provisions for planned equipment to enable efficient growth and avoid significant and premature station rebuild requirements, which could be costly. The planner needs to evaluate viable alternatives to select the most cost-effective solution. The plan would also determine the feasibility of the substation in its ultimate configuration, carrying the maximum planned load along with the ultimate feeder exit plan.

Planning Areas

Planning areas have geographic boundaries with customers and loads served by substations and feeders. The areas have load, topographical, and customer density characteristics. Historical load growth, reliability, and resiliency factors help planners determine proper sources, contingency mitigation, and resiliency measures to obtain the desired system reliability. This includes consideration of critical customer services.

Critical Services: These are the loads where power needs to be maintained for human health and safety (power and water, including water provided by an irrigation organization or facility), sewer, wastewater treatment, communications (broadcasting and telecommunications), education, and emergency medical care.[10]

Downtown/City Center Areas: This represents a densely developed area, such as a downtown metropolitan area with a density of 4,000 residents per square mile and a population of at least 50,000.

Rural Areas: These areas represent the open country (small towns) with fewer than 10,000 residents, no large residential development, and low customer/load densities, including agricultural areas and forest reserves.

[9] RUS BULLETIN 1724D-101A
[10] Stafford Act, Title IV, Section 406, pp. 37–38.

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Table 29. Criteria for Different Types of Load Areas for General Guidance in Consideration of Design Resiliency Elements

Downtown/City Center Areas	Rural Areas
San Juan, Bayamón, Guaynabo, Carolina, Caguas, Ponce, Fajardo, etc.; downtown metro areas	No large residential development, low customer/load densities, agricultural areas, and forest reserves
Areas supplying more than 4,000 customers per mi^2	Areas supplying less than 4,000 customers per mi^2
Critical Services	
Water pumping	
Sewer	
Wastewater treatment	
Communications (including emergency communication systems)	
Education	
Emergency medical care	
Shelter/town centers	
Police stations	
Fire stations	

System Design and Capability Considerations

Design criteria:

a. N-1 is the preferred design criteria with adequate backup or ties. N-0 will be used for cases only when N-1 is not possible. Where N-1 is not possible, other means of maintaining an acceptable level of reliability should be considered.

Customer guideline:

b. 2,500 customers for a single normal configuration distribution feeder is recommended.

c. If a specific feeder situation does not allow the customer count to be within 2,500, management must discuss and approve the exception. Cost, reliability, feasibility, and any other relevant factors need to be considered in order to make the case for a higher customer count.

Overhead feeder sectionalization with distribution automation devices:

d. Average of 500 customers per section and design so automatic transfers can reliably occur and be within normal rating for a fault in any single segment.

Distribution Feeder Design

Feeder loading under normal conditions must be below the equipment's normal ratings.

Feeder loading may exceed normal ratings but remain under emergency ratings for a defined period (see 1.1) during emergencies (e.g., planned or unplanned outages) and emergency restoration.

New distribution feeders:

e. New distribution circuit infrastructure should be built to be capable of operating at 13.2 kV regardless of the existing operating voltage.

f. Any new or extended 4 kV, 7 kV, or 8 kV circuit will be minimized and, where required, built using 15 kV rated materials and dual voltage distribution transformers to facilitate future conversion to 13.2 kV when practical.

g. Care should be taken to ensure proper phase balance when creating new feeders or reconfiguring feeders.

h. Incorporate modern distribution lines and laterals, as well as contemporary voltage regulation and conservation voltage reduction (CVR) standards as required.

i. Provide provisions for monitoring the three-phase voltages, currents, neutral current, VARs, and MWs to SCADA systems and recorded in the data historian.

Distributed Energy Resources (DERs) and Non-Wire Alternatives (NWAs)

New feeders should be planned so that no thermal, voltage, or other violation occurs when a full native load is experienced. Consideration should be made for the future forecasted DERs in the feeder and for future masking of the native load.

The following points should be considered:

j. Capacitor banks should be switchable and capable of remote operation (bidirectional communications).

k. Voltage regulators should have a co-generation mode and auto-determination of source. This will allow proper voltage regulation if distributed generation causes backflow, and in feeder reconfiguration, where the substation source is on the other side, the regulator will regulate away from the substation.[2]

When planning for a new substation, space provisions for future services, including energy storage integration should be considered. In addition, rooftop solar on the substation building can be considered.

Where NWAs are feasible and cost-effective, their use should be considered in place of typical distribution upgrades.

Storm Resilience

Resilient substation considerations:

l. 500-year flood design advisory base flood elevation (ABFE) plus 2 ft (Ref: ASCE 24-14 Flood Resistant Design and Construction) considering the latest FEMA ABFE maps.

m. Landslide evaluation and risk mitigation where landslide risk is present.

Trees/vegetation areas:

n. In areas where traditional reliability measures are ineffective, targeted undergrounding should be considered (remote mountain communities and dense urban areas with prevalent unmitigated exposure).
o. Tree wire (spacer) and consistent vegetation management may be used where undergrounding is not feasible. Refer to the distribution design criteria for more details.

Reducing the Risk of Wildfire Ignition from the Distribution System

Planning for areas with elevated wildfire risks may consider the following methods of reducing the risk:

Using underground vs. overhead circuits
Using insulated conductors for overhead lines
Setting protection relays appropriately (during high-risk periods)
Employing SCADA communications for operational flexibility and improved event response
Relocating high-risk overhead lines

Design Exceptions

If a proposed feeder or substation project cannot be built with the proposed solutions, the planning engineer will revisit feasible alternatives.
The design exceptions must be documented, and the alternative solution should be approved by the Manager of Distribution Planning and the Director of Planning and Renewable Integration.

Planning Criteria

Reactive Support

1. Feeder capacitor and regulator installations are recommended on feeders to achieve a power factor of at least 0.95 lagging during peak load time.

2. Switched capacitors with bidirectional communications capabilities should facilitate voltage and VAR management and remote operation.
3. Feeder capacitor size and location will be designed to optimize voltage management and minimize losses in normal planned configuration(s) at the time of design.

Voltage Unbalance

The maximum voltage unbalance should not exceed 3% using the ANSI voltage unbalance equation for calculation.

Harmonics

According to IEEE Standard 519, limits on voltage harmonics should be limited to 5% for total harmonic distortion (THD) and 3% for any single harmonic for voltage levels between 1 kV to 13 kV class as applicable in the LUMA system Table 30.

Table 30. Voltage Distortion Limits According to IEEE

Bus Voltage at PCC	Individual Harmonic (%)	Total Harmonic Distortion THD (%)
$V \leq 1.0$ kV	5.0	8.0
1 kV < $V \leq 69$ kV	3.0	5.0

Voltage Fluctuation

1. IEEE Standard 1453 recommends a certain limit on voltage fluctuation. These recommendations should be used to estimate the impact of a new load and DERs.
2. Although no specific fluctuation limit is mentioned for the DG/PV-related projects in IEEE Standard 1453, it is recommended from the Rapid Voltage Change section of the standard to limit the voltage fluctuation to 3%.

Distribution Substation Design

Please reference the distribution substation design guide.

Appendix A: Planning Criteria Summary

A.1 Overloading Limits

Continuous limits: 100% for equipment's nameplate rating. An upgrade should be recommended at 90% for the equipment's nameplate rating for planning purposes.

Emergency limits: 120% of continuous rating.

A.2 Voltage Limits

High voltage limit: 1.05 pu (126 V on a 120 V base).

Low voltage limit: 0.975 pu (117 V on a 120 V base) if only the primary side is modeled.

0.95 pu (114 V on a 120 V base) if secondary is modeled (V < 600 V).

Note: Only ANSI C84.1 Range A limits are used for planning.

A.3 Imbalance Limits

Voltage imbalance limit: 3%.

A.4 Maximum Fault Current to Interrupt

Substation circuit breaker, 15 kV Class: 31 kA RMS.

Line recloser, 15 kV Class: 16 kA RMS.

A.5 Maximum Loading of Substation Transformer for Reverse Power Flow

Reverse power flow through substation transformer: Not allowed.

A.6 Maximum Number of Operations in Voltage Regulation Devices

The number of operations will be limited by limiting maximum voltage fluctuation caused by online devices such as DER on the LTC, voltage regulators, and switched capacitors to half of the bandwidth.

A.7 Maximum Voltage Variations due to Cloud Cover Variations (PV-DG Projects)

Maximum voltage variation at any phase at the point of interconnection (POI): 3%.

A.8 The Limit and Maximum Increase in Fault Current (PV-DG Projects)

Maximum increase in fault current at the POI: 10%.

The absolute limit for fault current of any equipment should be at or lower than 90% of its fault interruption capability, including customer-owned equipment.

Appendix B: References

B.1 Applicable Standards and References

ANSI C84.1 – Electric Power Systems Voltage Ratings (60 Hz)

IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE 519-2022 – IEEE Standard for Harmonic Control in Electric Power Systems

IEEE 1453 - IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems

Rural Utilities Service Standards

Puerto Rico ACT 17-2019 – Puerto Rico Energy Public Policy Act

Regulation 8915/16 – DER Interconnection Regulation

National Electric Code (NEC)

National Electric Safety Code (NESC)

LUMA Technical Interconnection

LUMA Standards (see below)

NERC Glossary of Terms

B.2 Internal References

4300.001 Distribution Design Criteria Document

4301.001 OVERHEAD ELECTRICAL DISTRIBUTION SYSTEM MANUAL

4325.001 Underground Electrical Distribution System Manual

4350.018 Voltage Regulator

4350.017 - Three Phase Power Converter Distribution Transformers

4350.185 Pole Mounted Capacitor Bank for Controlled (Switched) Operation

4350.175 Pole Mounted Capacitor Bank for Continuous (Fixed) Operation

Appendix 2: Prior Action Plan Implementation Status Update

NEPR-AP-2023-0004

9.0 Overview

This section presents an updated summary of the implementation status of the Action Plan originally outlined in the 2019 Integrated Resource Plan (2019 IRP) and subsequently modified by the Puerto Rico Energy Bureau (Energy Bureau) through its Final Resolution and Order[11] (August 2020 R&O). In compliance with Section 2.03(L) of Regulation 9021, this update provides a structured assessment of progress made, deviations from the initial schedule or scope, and adjustments resulting from regulatory directives or intervening events.

The status update addresses the following elements:

- An itemized list of each component of the prior 2019 IRP Action Plan, as amended by the Energy Bureau.
- Actions taken by the Puerto Rico Electric Power Authority (PREPA, and now LUMA, where applicable) to implement each action item.
- Changes to the expected commencement and completion dates, permitting or regulatory requirements, or the removal of action items because of subsequent determinations by the Energy Bureau.
- Updates to permitting, engineering, or construction processes for major projects currently underway.
- Explanations for any changes to the original Action Plan due to regulatory, technical, or operational factors.

Following the Energy Bureau's August 2020 R&O, the original 2019 IRP Action Plan was refined and reorganized around three key pillars:

Greening the Supply: The 2019 IRP target of 1,800 MW of solar photovoltaics (PV) and 920 megawatts (MW) of battery energy storage systems (BESS) during the first five years was revised by the Energy Bureau to require a more aggressive renewable procurement schedule.

The Energy Bureau directed the procurement of approximately 2,760 MW of solar photovoltaics and 1,440 MW of BESS by 2025, to be executed through competitive Request for Proposal (RFP) tranches overseen by the Independent Coordinator (IC). The Energy Bureau also rejected proposals for new large-scale baseload gas generation (e.g., Costa Sur Combined Cycle Gas Turbine [CCGT] and Yabucoa CCGT) and mobile gas turbines, while allowing limited gas conversions (e.g., Mayagüez units), subject to further analysis and approval.

Creating a Resilient Grid: The Energy Bureau accepted the 2019 IRP's emphasis on hardening transmission and distribution (T&D), however, it did not approve the geographic MiniGrid zones as proposed by PREPA. Instead, the Energy Bureau initiated a separate optimization process for the configuration of resilient grid segments. Transmission projects, including 115 kilowatts (kV) and 38 kV

[11] Puerto Rico Energy Bureau. (2020). *Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan*, CEPR-AP-2018-0001. https://energia.pr.gov/wp-content/uploads/sites/7/2020/08/AP20180001-IRP-Final-Resolution-and-Order.pdf

upgrades, gas-insulated switchgear (GIS) substation conversions, and undergrounding of critical feeders, remain priority investments, subject to updated capital planning and justifications.

Engaging the Customer: The Energy Bureau retained and reinforced targets for customer-centric initiatives, including a 2% annual energy efficiency (EE) savings target (approximately 600+ gigawatts per hour [GWh] by 2025, however, these targets were modified by the Energy Bureau in subsequent proceedings), demand response (DR) programs targeting 60 MW, and distribution upgrades to integrate distributed energy resources (DERs) and prioritize critical feeders.

10.0 2019 IRP Action Item List

10.1 Greening the Supply

The Energy Bureau, through its August 24th Resolution and Order, approved the IRP with modifications to the Action Plan submitted by the Puerto Rico Energy Authority in the 2019 IRP filing. The following list represents the modified Action Plan as per the modifications made by the Energy Bureau:

1. **Implement six procurement tranches through competitive RFPs, as follows**:

- Tranche 1 (Dec. 2020): 1,000 MW solar + 500 MW of 4-hour storage
- Tranche 2 (June 2021): 500 MW solar + 250 MW storage
- Tranche 3 (Dec. 2021): 500 MW solar + 250 MW storage
- Tranche 4 (June 2022): 500 MW solar + 250 MW storage
- Tranche 5 (Dec. 2022): 500 MW solar + 125 MW storage
- Tranche 6 (June 2023): 750 MW solar + 125 MW storage

2. **Cumulative targets by 2025:**

- 3,750 MW of solar PV
- 1,500 MW of BESS

3. Hydro facility refurbishment

- PREPA must complete feasibility studies for each hydroelectric facility within 180 days of the R&O.
- Each study must assess:
    - Upgrade potential
    - Flexible dispatch capability
    - Generation timing value in a high-solar grid
    - Cost-effectiveness
- PREPA must submit an action plan for each hydro asset based on study findings [12].

4. **Gas infrastructure constraints:**

- The 302 MW Costa Sur CCGT and Yabucoa CCGT were explicitly rejected.

[12] Puerto Rico Energy Bureau. (2021). *Motion to submit presentation in compliance with the July 23, 2021, order*. NEPR-MI-2021-0012. https://energia.pr.gov/wp-content/uploads/sites/7/2021/08/20210819-Motion-to-Submit-Presentation-in-Compliance-with-the-July-23-2021-Order.pdf

- New baseload gas generation is not permitted under the baseline scenario.
- Mobile gas turbines are not approved.
- Natural gas conversions (e.g., Mayagüez peakers) may only proceed after:
    - Comprehensive cost-benefit analysis
    - Fuel supply assessment
    - Explicit Energy Bureau approval
    - San Juan Units 5 & 6 gas conversion is considered complete and not subject to further review.

5. Palo Seco contingency planning

- PREPA may spend up to $5 million on preliminary studies (siting, permitting, planning) for a new fossil-fuel or storage unit at Palo Seco.
- These funds:
    - May not be used for construction
    - Must not delay renewable procurements
    - Require Energy Bureau oversight and quarterly reporting

6. **EcoEléctrica Power Purchase Operating Agreement (PPOA) renegotiation:**

- May continue if it results in significant fixed cost reductions and flexible dispatchability. Otherwise, it would not be prioritized for continued capacity.

10.2 Creating a Resilient Grid

The objective is to improve the electric system's reliability and readiness for emergencies through targeted hardening and intelligent sectionalization categorized by operational necessity**:**

1. **115 kW upgrades:**

- Priority 1 (2020–2022): $2.05B
- Priority 2 (2023–2024): $322 million
- Focus areas: reconductoring, structural replacements, new circuits for resilience

2. **38 kW upgrades:**

- Priority 1 (2020–2022): $1.82 billion
- Priority 2 (2023–2024): $619.4 million

- Includes interconnection of critical loads, backbone extensions, and reliability reinforcements

3. **Substation modernization**

- Convert substations to GIS across critical locations
- Total estimated investment: approximately $177 million to be prioritized based on reliability and load-serving criteria

10.3 Engaging the Customer

The objective is to modernize the distribution grid for DER readiness, empower demand-side management, and integrate DG.

1. **Distribution Grid Modernization for DER Integration:**

- Identify and upgrade feeders with high-hosting capacity
- Prioritize smart inverters, voltage controls, and real-time monitoring
- Submit annual Distribution Planning Reports with detailed feeder assessments

2. **EE targets:**

- Achieve 2% annual savings, beginning in 2021
- Equivalent to approximately 600 GWh by 2025 and over 5,800 GWh by 2030
- Includes residential and commercial lighting and heating, ventilation, and air conditioning (HVAC), appliance efficiency

3. **DR programs:**

- 400 MW target by 2030
- Deploy 60–100 MW in early phases (2021–2025)
- Leverage advanced metering infrastructure (AMI), aggregators, and load curtailment during peak events
- Develop programs and tariffs to enable aggregated customer-sited DERs to participate as VPPs
- Allow VPPs to participate in future RFPs and model VPPs and DERs as resources in the next IRP

11.0 2019 IRP Action Item Status

11.1 Greening the Supply

11.1.1 Utility-Scale Solar PV Progress

The implementation of the utility-scale solar procurement strategy outlined in the 2019 IRP has progressed incrementally through a tranche-based framework. Tranche 1, launched in 2020 and still ongoing, has yielded to date: a total of 739 MW of contracted solar PV capacity. Projects awarded under Tranche 1 include large-scale facilities such as CFE Salinas and CFE Jobos, Yabucoa YFN, Ciro Two, among others. Some of these projects have commenced construction, while others are under active development. Most are in the permitting, financing, and interconnection phase, with commercial operation dates (CODs) generally ranging from early 2026 through 2027.

Tranche 2, initially targeted for release in 2022, resulted in 3 projects, two of them of solar PV for a total of 66 MW.

Outside of the formal tranche framework, approximately 200 MW of additional utility-scale solar PV has been contracted through non-tranche processes. These projects are Ciro 1 and Xzerta.

Table 31: Summary of Contracted Utility-Scale PV Capacity by Procurement Tranche

Tranche	Contracted PV Capacity (MW)
Tranche 1	739
Tranche 2	66
Non-Tranche	200

Table 32: Contracted Utility-Scale Solar Projects

Program/Source	Project Name	Approved Contracts (MW)	COD
Tranche 1	Juncos Solar	125	Nov-25
	AES Salinas	120	Mar-26
	Coamo	100	May-26
	Jobos	80	Sep-26
	Barceloneta	70	Mar-26
	Ciro Two	68	May-26
	Guayama	50	Mar-26
	Yabucoa YFN	32.1	May-26

	Yabucoa Energy Park	38.7	Aug-26
	Solaner San German	35	Sep-26
	Tetris Power	20	Mar-26
[redacted]			
Non-Tranche	Ciro One Phase 1	90	Aug-25
	Ciro One Phase 2	50	May-26
	Xzerta	60	Oct-27

11.1.2 Battery Energy Storage Progress

Under the ESM Plan, the IRP originally proposed the deployment of 920 MW of BESS over a five-year period to support the integration of solar PV and enhance system flexibility, including potential MiniGrid operations. This target was to be fulfilled through competitive procurements issued in blocks of 150 to 200 MW, covering both standalone BESS and co-located solar-plus storage projects.

However, the Energy Bureau's Final R&O expanded and formalized this strategy under the Modified Action Plan, establishing a new cumulative goal of 1,500 MW of four-hour BESS paired with up to 3,750 MW of utility-scale solar PV across six tranches through 2030. The 2025 IRP no longer distinguishes between two-, four-, or six-hour durations in its approved procurement framework. Instead, the Energy Bureau did not prescribe fixed configurations for BESS, and it required PREPA to use competitive solicitations to determine optimal size and duration based on cost and system needs.

As of mid-2025, progress toward the BESS target reflects a structured and phased implementation aligned with the Energy Bureau's Final R&O. Approximately 1,045 MW of BESS have been contracted or modeled across various tranches and the Accelerated Storage Addition Program (ASAP) phases, supporting the renewable integration strategy and system reliability objectives.

Table 33: Summary of Contracted and Modeled BESS Projects

Program/Source	Project Name	Capacity (MW)	Duration	Estimated COD
Tranche 1	CFE Salinas BESS	175	4-hour	Mar-26
	CFE Jobos BESS	110	4-hour	Sep-26
	Peñuelas BESS	100	4-hour	May-26
	Pattern Barceloneta BESS	50	4-hour	Feb-27
	Pattern Santa Isabel BESS	50	4-hour	Apr-27
	Ponce BESS	25	4-hour	Mar-26
	Caguas BESS	25	4-hour	Mar-26

2025 Integrated Resource Plan Report

Program/Source	Project Name	Capacity (MW)	Duration	Estimated COD
ASAP Phase I	EcoEléctrica	20	4-hour	May-26
	Horizon Energy	20	4-hour	May-26
	Oriana Energy	50	4-hour	May-26
	San Fermin Solar Farm	20	4-hour	May-26
	Punta Lima Wind Farm	40	4-hour	May-26
	Fonroche	40	4-hour	May-26
ASAP Phase II	Punta Lima Wind Farm	28	4-hour	Dec-26
	Landfill Gas Technologies Fajardo	7	4-hour	Dec-26
	Landfill Gas Technologies Toa Baja	7	4-hour	Dec-26
	San Fermin Solar Farm	52.5	4-hour	Dec-26
	Fonroche	28	4-hour	Dec-26
	CS-UR JUNCOS PV (Juncos I PV)	2.8	4-hour	Dec-26
	XZERTA-TEC	42	4-hour	Dec-26
	Solaner	28	4-hour	Dec-26
	Yabucoa YFN	35	4-hour	Dec-26
	Tetris Power	14	4-hour	Dec-26
	Ciro One	98	4-hour	Dec-26
	Ciro Two	47.6	4-hour	Dec-26
	Guayama Solar Energy	35	4-hour	Dec-26
Genera Proposed BESS	Aguirre	158	4-hour	2027
	Cambalache	52	4-hour	2025
	Costa Sur	30	4-hour	2025
	Palo Seco	101	4-hour	2026
	Vega Baja	49	4-hour	2025

Program/Source	Project Name	Capacity (MW)	Duration	Estimated COD
	Yabucoa	40	4-hour	2026
Total Capacity		**1, 689.9**		

11.1.3 Hydro Facility Refurbishment

The August 24, 2020, Final R&O (Case No. CEPR-AP-2018-0001) directed PREPA to complete feasibility studies for each of its hydroelectric generation facilities within 180 days. Each study was required to evaluate the potential for equipment upgrades, flexible dispatch capability, the value of generation timing in a high-solar grid, and cost-effectiveness. PREPA was further required to submit an action plan for each hydro asset based on the findings of these studies.

On February 22, 2021, PREPA requested an extension to complete the studies, informing the Energy Bureau that Black & Veatch Puerto Rico, PSC, had been retained to prepare the report. The Energy Bureau subsequently opened Case No. NEPR-MI-2021-0012 to monitor compliance with this requirement. On June 30, 2021, PREPA filed its final submission, including the Feasibility Study for Improvements to Hydroelectrical System – Task 700 Summary Report, and detailed facility-specific evaluations prepared by Black & Veatch.

The study identified opportunities to increase operational hydroelectric capacity from approximately 38.8 MW to 91.7 MW, with an expected improvement in the overall capacity factor from 0.06 to 0.28. Recommended measures include turbine and generator refurbishments, penstock and conveyance system repairs, digital governor and control upgrades, sediment removal from reservoirs, and the implementation of modern remote-operation capabilities to allow centralized dispatch from the Energy Control Center. Facilities such as Caonillas 1 (20 MW) and Dos Bocas (15 MW) were highlighted for near-term interventions, while Toro Negro and Garzas plants were identified as having significant potential for incremental generation through targeted upgrades.

To review these findings, the Energy Bureau held a technical conference on August 23, 2021, where PREPA and Black & Veatch presented the study's conclusions and responded to questions from the Energy Bureau's staff and consultants. Discussions focused on the economic viability of the proposed refurbishments, operational flexibility under a high-renewable grid scenario, and the prioritization of projects maximizing reliability and generation benefits. PREPA was instructed to finalize an action plan incorporating these recommendations and to submit implementation schedules and cost projections for each facility.

11.1.4 Conversion of San Juan Units 5 & 6 to Natural Gas

The 2019 IRP included the conversion of the San Juan Combined Cycle (CC) Units 5 and 6 from heavy fuel oil to natural gas as a committed action under the ESM Plan. At the time, this project was considered a near-term implementation priority based on its potential to reduce emissions, improve operational efficiency, and support system flexibility during the renewable energy transition.

As of 2025, the conversion of San Juan CC Units 5 and 6 has been completed. Both units are now operational and fueled by natural gas. The liquified natural gas (LNG) is supplied via a ship-based terminal solution located at the San Juan port, which enables delivery of gas through onboard regasification and pipeline connection to the San Juan generation site. The capacity and operating

characteristics of these units remain consistent with the original configuration, and each unit provides approximately 200 MW of capacity.

Key attributes as of the 2025 Reliability Report:

- **Operating Status**: Active
- **Fuel Type**: Natural Gas
- **Combined Capacity (Units 5 & 6)**: Approximately 400 MW
- **Startup Fuel and Infrastructure**: Supplied via LNG ship-based terminal
- **Dispatch Role**: Thermal baseload/flexible resource

11.1.5 EcoEléctrica PPOA Renegotiation and Extension

The 2019 IRP indicated that EcoEléctrica could only remain in operation beyond the expiration of its PPOA in 2022 if PREPA successfully renegotiated the contract to achieve material reductions in fixed payments and improved dispatch flexibility. PREPA's modeling assumed a 53% reduction in fixed payments under the "Retain" scenario, but even at that level, EcoEléctrica did not appear in the least-cost resource portfolios under most planning cases. The Energy Bureau noted that a 60% reduction in fixed costs might be required to achieve breakeven economics. If those conditions were not met, the 2019 IRP proposed replacing EcoEléctrica with a 302 MW combined-cycle gas turbine (CCGT) at Costa Sur. However, the Energy Bureau ultimately rejected the Costa Sur CCGT proposal, citing a shift away from new baseload natural gas infrastructure.

In response, PREPA executed a First Amendment to the PPOA in October 2021, which extended the contract through September 30, 2032, introduced a defined Capacity Payment, a Fuel Handling Fee, and a Heat Rate Adjustment (HRA) Payment based on fuel efficiency, and required biennial performance testing to confirm dependable capacity.

Subsequently, in August 2023, LUMA submitted an Amended and Restated PPOA as part of its 2024 Approved Operational Plan (AOP), which further clarified operational terms, restructured governance, and integrated a payment framework aligned with dispatch flexibility and cost efficiency. The Energy Bureau approved the AOP, acknowledging that the updated PPOA addressed the 2019 IRP's concerns regarding cost and operational performance, while also preserving EcoEléctrica's role as a critical transitional resource under Puerto Rico's evolving energy landscape.

11.1.6 Palo Seco Contingency Planning

The 2019 IRP, approved by the Energy Bureau in August 2020, identified the Palo Seco Steam Plant as a critical node for maintaining reliability in the San Juan metropolitan area. The 2019 IRP acknowledged the aging oil-fired units at the facility and the need for dispatchable capacity to complement the growing share of renewable energy. Under the Modified Action Plan, the Energy Bureau authorized up to $5 million for preliminary studies at Palo Seco to assess the feasibility of a new fossil-fuel or storage unit. These studies were limited to economic, siting, permitting, and planning analysis, and the Energy Bureau explicitly prohibited any construction activities or delays to the procurement of solar and battery resources under the competitive RFP tranches.

The Energy Bureau's 2020 Final R&O set clear directives for Palo Seco. Any future fossil generation would have to be justified through a thorough cost-benefit analysis against battery storage and other alternatives. PREPA was required to submit periodic reports describing expenditures, consultants engaged, and progress toward evaluating contingency capacity at the site. In addition, any new fossil resource would need to be hydrogen-ready or capable of conversion to renewable fuels and procured through a competitive process approved by the Energy Bureau.

Between 2021 and 2022, PREPA, in coordination with the Federal Emergency Management Agency's (FEMA) Hazard Mitigation Grant Program (HMGP), commissioned Sargent & Lundy to conduct the Palo Seco feasibility studies. HMGP allocated approximately $13.5 million for engineering and permitting efforts (Phase I), which overlapped with the $5 million 2019 IRP allocation. Phase I focused on engineering analysis, fuel logistics, environmental permitting, and cost modeling for various technology options, including CCGT, reciprocating internal combustion engines (RICE), and BESS. The July 15, 2022, Feasibility Study concluded that the San Juan Steam Plant site was a stronger candidate for new generation due to its existing LNG infrastructure and lower logistical risks. The report noted that Palo Seco would require costly high-pressure pipeline construction from San Juan, estimated at over $100 million, and lacked direct port access, making it a less viable option. Sargent & Lundy recommended that no new CCGT be developed at Palo Seco and that FEMA mitigation funding be prioritized for San Juan or other sites with existing natural gas access. It should be noted that the recommendation of this study was one of the principal drivers in LUMA's decision to limit new CCGT additions to San Juan and Costa Sur in the 2025 IRP.

In response, the Energy Bureau issued its August 3, 2022, R&O, ordering PREPA to redirect FEMA funds originally tied to Palo Seco toward energy storage projects at the site to improve grid resilience without expanding fossil infrastructure. It also reaffirmed that any new fossil generation must be competitively procured, hydrogen-ready, and fully justified under Act 17-2019's renewable targets. On October 19, 2022, the Energy Bureau denied PREPA's motion for reconsideration, filed on August 23, 2022.

From 2023 onward, the focus at Palo Seco shifted from building new fossil generation to operational optimization of existing assets. Genera PR, as the operator of PREPA's generation fleet, proposed converting the MobilePAC units (27 MW each, installed in 2019) from ultra-low sulfur diesel (ULSD) to LNG. This conversion is expected to reduce operational costs by $12 million to $18 million annually due to the lower fuel cost of LNG compared to ULSD. The Energy Bureau reviewed these proposals under docket MI-2024-0004, issuing multiple resolutions throughout 2024 and 2025 that required additional technical and economic justification before it issued a final decision.

11.2 Creating a Resilient Grid

The objective is to improve system reliability, reduce outage durations, and enhance readiness for severe weather events by focusing on targeted T&D upgrades, substation modernization, undergrounding of critical feeders, and advanced automation.

11.2.1 Transmission System Upgrades

The 2019 IRP highlights significant needs for 115 kV and 38 kV backbone reinforcements.

Key Upgrade Categories:

- Reconductoring of aging lines to increase ampacity and resilience.
- Structural tower replacements and rebuilds in storm-prone corridors.
- New line sections to close reliability gaps and enable redundancy.

Table 34: Transmission Projects Status

Voltage Level	Project Name/Description	Purpose	Estimated Cost
115 kV	**Línea Cambalache - Dos Bocas**	Increase transfer capacity and reliability	Pending
115 kV	**Línea Aguirre - AES / Yabucoa - Sabana Llana (L41400)**	Enhance renewable integration and load support	Pending
115 kV	**Corredor Este-Oeste (Canóvanas - Sabana Llana L41200 y L36800)**	Harden major transmission corridors	$10.84M (Line L41200), $11.05M (Line L36800)
115 kV	**Reconditioning of Arecibo and Bayamón - Sections**	Structural hardening in high-demand regions	Pending
115 kV	**Costa Sur - Aguirre / Costa Sur - EcoEléctrica (L40300)**	Reconductoring to address thermal violations	$13.96M (Line L41400)
115 kV	**Mayagüez-Alturas Mayagüez/ Mora (L37200)**	Reconductoring to increase transfer capacity	$21.79M (Line L40300)
115 kV	**Berwind -M. Peña GIS**	Reconductoring and reliability reinforcement	$4.93M (Line L37200)
115 kV	**Berwind -Escorial**	Reconductoring to address thermal overloads	$7.33M
115 kV	**S. Llana -Escorial**	Reconductoring for resilience and capacity	$2.36M
115 kV	**Hato Rey -M. Peña GIS**	Reconductoring for improved voltage stability	$1.68M
115 kV	**Corredor SJSP -Segmento Viaducto**	Rebuild of key metro corridor segment	$2.96M
115 kV	**Updates to Backbone in Ponce, Mayagüez, Aguadilla**	Upgrade for metro grid reinforcement	$11.63M
38 kV	**Feeder Reinforcement of San Juan Metro Area**	Improve critical load interconnection and regional resilience	Pending
38 kV	**Replacement of Palmer Transformer**	Support hospitals and water utilities	Pending
38/115 kV	**Replacement of Añasco Transformer**	Increase transformer capacity and reliability	$10M
38/115 kV	**Replacement of Barranquitas Transformer**	Replace aging equipment to enhance resilience	$10M
38/115 kV	**Replacement of the Mayagüez Plant's Transformer**	Improve load handling and stability	$10M

Voltage Level	Project Name/Description	Purpose	Estimated Cost
38/115 kV	**Línea Cambalache - Dos Bocas (40 CAMBALACH115 -3801 DOS BOCA _02)**	Replace existing transformer for capacity and reliability	$10M

This includes project-level cost ranges (e.g., $5 million–$20 million per line upgrade) but does not aggregate total costs for Priority 1 or Priority 2 upgrades.

11.2.2 Substation Modernization (GIS)

The Appendix lists 43 substations planned for major modernization or rebuild, with a strong emphasis on GIS adoption, flood mitigation, and digital automation.

Objectives:

- Upgrade to GIS technology for compact, weather-resistant design.
- Install digital protection relays, redundant breakers, and real-time monitoring.
- Flood mitigation through elevation or relocation in high-risk areas.

Table 35: PBUT8 Substation Rebuild Projects with GIS Modernization

Region	Sites (Total)	Distribution Substations	New Distribution Transformers	Capacity Increase (Δ MVA)
Arecibo	5	6	6	27.4
Bayamón	9	13	11	116.5
Caguas	1	2	3	20.9
Mayagüez	3	5	5	36.2
Ponce	6	7	8	61.2
San Juan	17	25	28	214.5
Total	41	58	61	476.7

11.3 Recent Grid Updates

The objective is to modernize the distribution grid for DER readiness, empower demand-side management, and integrate DG.

11.3.1 Distribution Grid Modernization for DER Integration

Since the issuance of the 2019 IRP, LUMA has advanced a modernization strategy to enable large-scale integration of DER. Puerto Rico's distribution grid has reached a critical juncture due to unprecedented growth in DER. As of today, over 155,000 DER systems, representing more than 1,100 MW of installed capacity, are interconnected, with approximately 4,000 new systems added each month.

In alignment with the Energy Bureau's R&Os, the process began with the December 31, 2020, directive requiring the creation of voltage level maps, interconnection capacity maps, and a complete power grid inventory. PREPA and LUMA submitted an initial joint work plan in early 2021, leading to the first version of the Voltage Level Map (May 2021) and the Interconnection Capacity Map (September 2021). These tools were designed to help customers and developers identify feeders with available hosting capacity and to streamline interconnection planning.

By mid-2022, the Energy Bureau recognized the growing demand for DER interconnections and, through its May 26, 2022, R&O, required LUMA to enhance the maps by providing localized interconnection data, including service transformer capacities and secondary conductor specifications, upon request. This order also mandated monthly updates to the voltage level and hosting capacity maps, ensuring that the tools reflected field changes such as load transfers, voltage upgrades, and new DG connections.

Throughout 2023 and early 2024, LUMA invested in improving its Geographic Information System (GIS) and Grid Transmission and Automation Control (GTAC) tools to provide more accurate feeder-level data. Field verification of feeders, combined with incremental hosting capacity analyses, became a core part of LUMA's Cluster Study process. These updates capture key changes such as feeder voltage conversions (e.g., from 4 kV to 13.2 kV), aggregate DER penetration exceeding 15%, and large load transfers. These studies directly guide investment in conductor reinforcements, voltage regulators, and capacitor bank optimizations to expand the system's hosting capacity and reliability.

On April 11, 2024, the Energy Bureau issued an R&O requiring LUMA to submit an updated implementation plan by May 1, 2024, and to discuss progress at a technical conference. In its May 2024 filing, LUMA confirmed that voltage level and DG penetration maps would continue to be updated biweekly, with incremental hosting capacity analyses expanded to include at least 20 additional feeders.

Building on these technical enhancements, LUMA's studies have now evaluated 769 feeders, providing detailed visibility into system conditions and interconnection constraints. These studies reveal that over 769 feeders have revealed widespread technical issues, 772 service transformers are overloaded, 652 capacitor banks require upgrades, and 17 voltage regulators and 12 feeder sections have been flagged for reinforcement due to increased DER output. For example, cluster studies conducted on Feeder 8501-02 (Barceloneta, 4.16 kV) showed DER penetration at 52% of peak load, resulting in severe overvoltage events exceeding 126 V and transformer overloads of up to 44.7%. Similarly, Feeder 2301-02 (Río Grande, 8.32 kV) exhibited overvoltage in 460 sections and transformer overloading by up to 49%, indicating that no additional DER can be safely connected without immediate upgrades. Even higher-

voltage feeders, such as 6012-02 in Mayagüez (13.2 kV), are showing overvoltage up to 128.8 V and require reconductoring of specific segments to alleviate thermal overloads.

11.3.2 Smart Inverter Settings

In parallel with mapping and feeder reinforcement efforts, LUMA has worked closely with the Energy Bureau and stakeholders through the Smart Inverter Working Group (SIWG) to develop IEEE 1547-2018 compliant smart inverter settings tailored for Puerto Rico's electric system. These settings, focused on functionalities such as Volt/Watt (adjusts real power output based on voltage) and Volt/VAR (adjusts reactive power based on voltage) functions, are used in electric systems, particularly with solar inverters. Their purpose is to manage voltage, power output, frequency ride-through, and reactive power support. They are also designed to enhance feeder stability under high DER penetration.

Although LUMA's Technical Bulletin 2024-001 introduced a baseline for default smart inverter settings (effective January 1, 2025), the Energy Bureau has not finalized mandatory implementations for all new DER installations. As of now, the Volt/Watt function remains deactivated pending further evaluation, with the Energy Bureau scheduled to revisit this decision after June 30, 2025. This delay reflects concerns raised by stakeholders, including SESA, Enphase, and Tesla, regarding potential energy curtailments and the need for compensation mechanisms. The Energy Bureau has required a phased approach, with additional analysis on high-voltage events, customer protections, and technical thresholds before determining final enforcement.

Even without full mandatory adoption, smart inverter functions have proven critical during pilot deployments and site-specific implementations. Feeder studies have shown that applying Volt/VAR control and frequency ride-through improves hosting capacity and mitigates voltage excursions, particularly on high-penetration circuits like Barceloneta (4.16 kV) and Río Grande (8.32 kV). These functions complement physical grid upgrades by providing localized, automated grid support, reducing the immediate need for extensive infrastructure reinforcements.

As of June 2025, LUMA has filed a revised Smart Inverter Settings Sheet (Version 2.0) incorporating feedback from the SIWG and industry groups. This revision maintains compliance with IEEE 1547-2018 while adjusting thresholds and activation logic to reflect the operational conditions in Puerto Rico. The Energy Bureau is currently reviewing these proposals and stakeholder counter-proposals. Until a final R&O is issued, smart inverter settings remain under evaluation and are not universally required for all new DER interconnections.

11.3.3 Energy Efficiency Targets

LUMA's EE programs, implemented through the Transition Period Plan (TPP), continue to deliver incremental energy savings across residential and commercial sectors. As of FY2025 Q3, LUMA reported:

- Over 4,500 residential rebates issued for high-efficiency appliances.
- More than 750 EE kits are distributed to commercial customers.
- Point-of-sale discounts at 10 Home Depot locations, resulting in sales of 1,700 ceiling fans and 60 window AC units.
- Restoration of approximately 465,000 streetlights with light-emitting diode (LED) lamps across 35 municipalities.
- Based on recent projections, the EE program is expected to deliver approximately 32,300 MWh of savings for FY2025, representing approximately 0.2% of projected annual consumption.

11.3.4 Demand Response Programs

LUMA has significantly expanded its DR portfolio in response to anticipated resource adequacy challenges:

The Customer Battery Energy Sharing (CBES) pilot reached 9,549 enrolled customers, representing 60 MW of battery capacity. The CBES+ emergency expansion was approved in May 2025 and is expected to deliver additional firm capacity during summer 2025 events.

The newly approved Emergency Load Reduction Program (ELRP) targets 50 MW of dispatchable capacity from large customers with backup generators. Customers receive $6/kW monthly capacity payments and $0.25/kWh per-event participation payments, with up to 75 events expected between June and October 2025.

LUMA continues developing mechanisms to enable aggregated customer-sited DERs to participate as VPPs, including Distributed Energy Resource Management System (DERMS) integration and alignment with the 2019 IRP modeling frameworks.

12.0 2019 IRP Action Item Updates

12.1 Greening the Supply

Progress on renewable generation and storage procurement continues under the tranche-based competitive bidding framework. Tranche 1 resulted in 739 MW of contracted utility-scale solar projects, while Tranche 2 has awarded 66 MW to date, with additional procurement activities pending. Approximately 200 MW of solar capacity has been contracted outside the tranche structure, contributing to the cumulative target set by the Energy Bureau's Modified Action Plan of 2,750 MW of solar PV and 1,440 MW of BESS by 2025.

BESS deployment has reached approximately 1,045 MW of contracted and modeled capacity across Tranches 1 and 2 and the Genera projects, as well as the ASAP phases. Projects range from standalone systems to co-located solar-plus storage facilities, with most systems designed with four-hour energy storage capacity. The commercial operation dates for these projects span from 2026 to 2027. These procurements were conducted through the competitive process established by the Energy Bureau, ensuring alignment with system needs and cost-effectiveness. Tranche 4 is also underway as part of the ongoing procurement efforts.

The conversion of San Juan CC Units 5 and 6 to LNG is complete, providing approximately 400 MW of capacity via ship-based regasification. The EcoEléctrica PPOA was amended and extended through 2032, with restructured payments and operational terms that support cost-effective and flexible dispatch. At Palo Seco, the studies authorized by the Energy Bureau have been completed, and subsequent FEMA-funded assessments have shifted the focus from new fossil generation to battery storage and operational improvements of existing units. Genera PR has proposed LNG conversions of the MobilePAC units at Palo Seco to reduce operating costs, with Energy Bureau oversight of technical and economic justifications.

12.2 Creating a Resilient Grid

T&D system hardening remains a priority. LUMA is implementing upgrades to the 115 kV and 38 kV transmission backbones, including reconductoring, structural tower replacements, and targeted line rebuilds to address thermal constraints and improve system reliability. Key projects include the Cambalache–Dos Bocas line, the Aguirre–AES/Yabucoa corridor, and the East-West 115 kV corridor. Several projects have defined cost estimates, while others are under evaluation for scope and budget finalization.

Substation modernization efforts continue, focusing on the adoption of GIS technology, installation of digital relays, and flood mitigation measures. A total of 43 substations are planned for modernization or rebuilding, with a combined increase of approximately 476.7 MVA of transformer capacity across major load centers.

Undergrounding of critical feeders is being evaluated through cost-benefit analyses and restoration studies. The strategy prioritizes urban areas and corridors with high vegetation exposure, where overhead hardening is insufficient. Microgrid controllers and advanced communication systems are planned for selective deployment, providing operational benefits and supporting localized islanding for critical loads.

12.3 Engaging the Customer

LUMA has expanded its efforts to modernize the distribution grid and integrate DERs. As of mid-2025, over 155,000 DER systems, representing more than 1,100 MW of capacity, are interconnected, with approximately 4,000 new systems added monthly. Hosting capacity and voltage level maps are updated regularly to support developers and customers, following the Energy Bureau's directives issued between 2021 and 2024. Feeder-level studies have been conducted to identify constraints such as overvoltage and transformer overloads, leading to targeted reinforcements and operational adjustments.

In collaboration with the SIWG, LUMA has developed IEEE 1547-2018-compliant smart inverter settings to enhance feeder stability. While full mandatory adoption of these settings is under the Energy Bureau's review, pilot implementations have demonstrated improvements in voltage regulation and hosting capacity.

For FY2026, LUMA will operate under a revised TPP budget of approximately $16.2 million for EE programs and $11.6 million for DR programs, aiming to achieve 32,375 MWh of energy savings and 70 MW of peak demand reduction. The EE portfolio will focus on residential rebates (e.g., heating, ventilation, and air conditioning (HVAC) and solar water heaters), in-store discount programs, and targeted initiatives for low-income customers, including 25,000 EE kits. Business customers will be served through rebates and 3,600 business EE kits designed to promote cost-effective upgrades in lighting, HVAC, and food service equipment.

In terms of DR, the CBES program is transitioning from pilot to full-scale implementation, targeting 28 MW of firm capacity by the end of FY2026. The Backup Generators (BUGs) program will complement CBES by enrolling large customers with standby generation to provide up to 36 MW of dispatchable capacity. Both programs will be supported by ongoing research, pilot initiatives, and development of additional DR measures, such as electric vehicle (EV) load management and behavioral DR.

These initiatives are structured to ensure continuity between the TPP and the forthcoming Three-Year EE and DR Plan (FY2027–FY2029). While the FY2026 budget constraints limit program expansion, LUMA will focus on maintaining program stability, achieving incremental savings, and preparing for a significant ramp-up in EE and DR efforts in subsequent years.

Appendix 3: Renewable Energy Project Status Update

NEPR-AP-2023-004

13.0 Introduction

This Appendix provides the Renewable Energy Project Status Update required by Regulation 9021, as part of the 2025 Integrated Resource Plan (2025 IRP) filing. It focuses on an assessment of DG and net energy metering (NEM) contributions to renewable portfolio standard (RPS) targets, based on actual and forecasted data.

13.1 Current Contracted Unbuilt Renewable Energy Projects

In alignment with Regulation 9021, Section 7 (Appendix 3), the following table presents a summary of power purchase and operating agreements (PPOAs) under development or construction across Puerto Rico. These projects are not part of the NEM or customer-based DG programs. Instead, they represent utility-scale renewable energy developments contracted with PREPA. The table includes key information such as location, capacity, technology, pricing terms, 2025 IRP status, permitting stage, and PREPA's assessment of project viability.

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Table 36: PPOA Project Overview

Company / Project Name	Contract No.	Location	Capacity (MW)	Technology	Contracted Energy Price ($/kWh)	Monthly Capacity Payment Price in Year 1 ($/MW-month)	Annual Escalator	*Expected Annual Generation (MWh)	Expected COD	Permitting / Construction Stage	PREPA Assessment of Likelihood
Ciro One	2011-P00043	Salinas	140	Solar	$0.10	-	2%	157,680 (Phase 1) 87,600 (Phase 2)	Aug-2025 (90 MW Phase 1) May-2026 (50 MW Phase 2)	Under construction	100%
XZERTA-TEC	2013-P00042	Hatillo	60	Solar	$0.10	-	1%	105,120	Oct-2027	Under development	100%
JUNCOS PV (Juncos I PV)	2022-P00126	Juncos	125	Solar	$0.13600	-	0%	219,000	Oct-2027	Under development	100%
AES Jobos Solar	2023-P00055	Guayama	80	Solar	$0.11066	-	2%	140,160	Sept-2026	Under development	100%
AES Salinas Solar	2023-P00054	Salinas	120	Solar	$0.11109	-	2%	210,240	Mar-2026	Under development	100%
Pattern Barceloneta Solar ITC	2022-P00120	Barceloneta	70	Solar	$0.15311	-	0%	122,640	Feb-2027	Under development	100%
Ciro Two Salinas	2022-P00124	Salinas	68	Solar	$0.09550	-	2%	119,136	Oct-2027	Under development	100%
Guayama Solar Energy	2022-P00125	Guayama	50	Solar	$0.10050	-	2%	87,600	Jul-2027	Under development	100%
Yabucoa YFN	2022-P00119	Yabucoa	32.1	Solar	$0.14690	-	2%	56,239	Apr-2026	Under development	100%
Yabucoa Energy Park Solar ITC	2023-P00035	Yabucoa	38.7	Solar	$0.13970	-	0%	67,802	Dec-2026	Under development	100%
Tetris Power	2022-P00118	Arecibo	20	Solar	$0.13850	-	1%	35,040	Mar-2027	Under development	100%
Solaner San German	2022-P00123	San German	35	Solar	$0.12190	-	2%	70,080	Oct-2026	Under development	100%

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Company / Project Name	Contract No.	Location	Capacity (MW)	Technology	Contracted Energy Price ($/kWh)	Monthly Capacity Payment Price in Year 1 ($/MW-month)	Annual Escalator	*Expected Annual Generation (MWh)	Expected COD	Permitting / Construction Stage	PREPA Assessment of Likelihood
Coamo Solar	2022-P00122	Coamo	100	Solar	$0.10003	-	2%	175,200	Mar-2027	Under development	100%
AES Jobos (BESS)- ITC	2023-P00052	Guayama	110	BESS	-	$25,117	2%	160,600	Sep-2026	Under development	100%
AES Salinas (BESS)- ITC	2023-P00053	Salinas	175	BESS	-	$25,096	2%	255,500	Mar-2026	Under development	100%
Caguas Energy Storage	2024-P00055	Caguas	25	BESS	-	$28,524	2%	36,500	Mar-2027	Under development	100%
Peñuelas Energy Storage	2024-P00054	Peñuelas	100	BESS	-	$28,669	2%	146,000	Mar-2027	Under development	100%
Ponce Energy Storage	2024-P00053	Ponce	25	BESS	-	$27,236	2%	36,500	Mar-2027	Under development	100%
Pattern Barceloneta BESS	2026-P00012	Barceloneta	50	BESS	-	$25,854	2%	73,000	Feb- 2027	Under development	100%
Pattern Santa Isabel BESS	2026-P00013	Santa Isabel	50	BESS	-	$26,673	2%	73,000	Apr- 2027	Under development	100%
[redacted]											

Notes:

- The expected generation numbers provided are for a full year (full 12 months).

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- For future solar projects, a 20% capacity factor was assumed.
- Isabela BESS is the only BESS project of 6-hour storage duration. All other BESS projects are 4-hour storage duration.
- For Future BESS projects, annual expected generation is based on 365 cycles per year. Each cycle is equivalent to each project's capacity times storage duration (capacity * x-hrs. * 365 days/cycles).

13.2 Renewable Energy Production and Renewable Portfolio Standard Compliance

Table 37 summarizes the anticipated renewable energy contribution from both utility-scale and distributed resources, and the projected compliance with Puerto Rico's RPS targets.

Table 37: Expected Utility-Scale and DG Generation (FY)

FY	Utility-Scale Renewable (MWh)	DG/NEM Renewable (MWh)	Total Renewable (MWh)	Base Load Forecast (MWh)	% of Total Load
2025	446,120	736,650	1,182,770	19,044,665.82	6.21%
2026	839,115	830,989	1,670,104	18,950,493.38	8.81%
2027	1,580,930	851,852	2,432,782	19,010,007.55	12.59%
2028	2,144,740	864,040	3,008,780	19,102,222.72	15.14%
2029	2,144,740	874,432	3,019,172	19,080,301.57	15.22%
2030	2,144,740	890,264	3,035,004	19,064,474.76	15.31%
2031	2,144,740	909,436	3,054,176	19,027,083.66	15.44%

*To consider Act 1-2025's RPS target in the 2025 IRP PLEXOS modeling, LUMA included a soft RPS target beginning on 2035, ramping up to 100% in 2050.

Note: As of August 2025, no expected Utility-Scale Renewable Energy project is scheduled officially to operate after 2028.

Appendix 4: Demand Side Resources Status Update

NEPR-AP-2023-004

14.0 Introduction

LUMA's EE and DR portfolios are composed of various Transition Period Plan programs and initiatives, which began in FY2024 and will run through FY2026. The Transition Period Plan programs' purpose is to provide greater understanding of the Puerto Rico market, customer needs and preferences, and how to best address barriers to adoption across LUMA's customer mix. This Appendix provides the Demand-Side Resources Status Update required by Regulation 9021, Section 2.03. – Integrated Resource Plan Analyses and Reporting Requirements N) Demand Side Resources Status Update, to accompany the 2025 Integrated Resource Plan (2025 IRP) filing. Appendix 4 includes an assessment of new and contracted demand-side energy and capacity projects, focused on EE and DR initiatives. LUMA is developing its first Three-Year Plan, to run from FY2027-FY2028 as required in the Energy Efficiency Regulation. It will expand the current EE and DR portfolio to bolster Puerto Rico's grid resilience and enhance emergency resource flexibility. The final plan will be submitted to the Energy Bureau in February 2026 for review and approval.

14.1 New Demand-Side Resource Programs

The programs presented on Table 38 represent the current EE and DR program portfolios. These programs will continue through the first Three-Year Plan period.

Table 38:Demand Side Resource Programs*

Program Name	Included as Existing Resource?	Included as Likely New Resource?	Expected Operation Date	Contracted Energy Price	Contracted Capacity Price	Other Expected Payments	Project Stage	Likelihood of Completion
Residential EE Kits Program	Yes	No	Operating		EE Rider	Administrative Costs	Implementation	
Residential EE Rebate Program	Yes	No	Operating	Incentives per unit	EE Rider	Administrative Costs	Implementation	
Business EE Kits Program	Yes	No	Operating	N/A (Free)	EE Rider	Administrative Costs	Implementation	
Business EE Rebate Program	Yes	No	Operating	Incentives per unit	EE Rider	Administrative Costs	Implementation	
In-Store EE Discounts Program	Yes	No	Operating	Discounts at POS	EE Rider	Administrative Costs	Implementation	
Streetlight Modernization	Yes	No	Operating	N/A	EE Rider	Infrastructure Modernization	Construction	
CBES (Customer Battery Energy Sharing)	Yes	No	Operating	$1.25 per kWh	Incentives recovered via PPCA	Administrative Costs/Incentives/ DERMS	Implementation	
Emergency Load	No	Yes	Summer 2025	Monthly Capacity Payment of	Incentives recovered via PPCA	Administrative Costs	Participant Recruitment	

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Program Name	Included as Existing Resource?	Included as Likely New Resource?	Expected Operation Date	Contracted Energy Price	Contracted Capacity Price	Other Expected Payments	Project Stage	Likelihood of Completion
Reduction Program				$6,000; Event participation incentive of $0.25 per kWh				

*Demand-side initiatives are critical to achieving load flexibility, peak reduction, and improved system efficiency. The costs associated with DR programs are recovered through the purchase power charge adjustment mechanism. The costs associated with EE programs are recovered through the Energy Efficiency Rider mechanism.

Appendix 5:

New Resources Option Report

15.0 Executive Summary

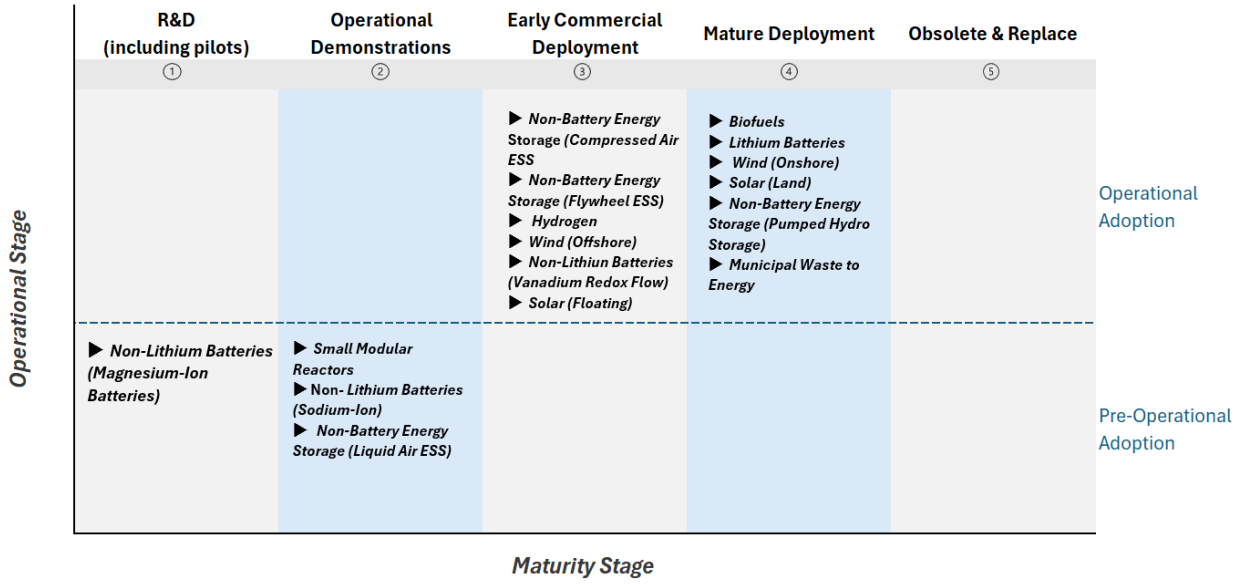
To identify candidate energy resource technologies for consideration in the Integrated Resource Plan (IRP), LUMA assessed several technologies for their cost, technological maturity, and applicability to Puerto Rico. Exploring new resources and technologies is critical to the future of energy in Puerto Rico. Appendix 5 highlights several technologies at various stages of technological maturity and commercial adoption. It serves as an overview of the resources and their potential viability in the Puerto Rican energy system. This analysis is divided into five primary categories of comparison: Technological Maturity, Cost, Supply Chain, Construction Timeline, and Sustainability. Conducting a comparative study of these technologies and currently adopted energy resources in Puerto Rico may help identify the most impactful solutions for the near-term future. The technologies examined in this report are shown in Table 39.

Table 39: New Potential Resource Options

<table>
<tr><th colspan="4">New Potential Resource Options</th></tr>
<tr><td rowspan="4">Non-battery storage:
Pumped hydro storage
Flywheel energy storage
Liquid air energy storage
Compression air energy storage</td><td rowspan="3">Non-Lithium BESS:
Sodium-ion
Magnesium-ion
Vanadium redox flow</td><td>Hydrogen</td><td>Offshore wind</td></tr>
<tr><td>Biofuels</td><td>Onshore wind</td></tr>
<tr><td>Small modular reactors</td><td>Municipal waste-to-energy</td></tr>
<tr><td>Lithium batteries</td><td>Floating solar panels</td><td>Land-based solar panels</td></tr>
</table>

15.1 Technological Maturity and Global Adoption

Figure 20: Reviewed Energy Technologies



The technologies included in this report range from maturely developed lithium batteries and onshore wind to those still in the research and development phase, such as magnesium-ion battery storage. These development categories are based on the global implementation of technology at a utility scale, as well as their demonstrated effectiveness in terms of cost and reliability (see Figure 20). Most technologies fall within the early commercial and mature development categories (stages three and four, respectively), indicating they have at least three operational projects globally that have demonstrated economic feasibility. Many stage three projects are adaptations or modifications of existing and more mature technologies, such as offshore wind and floating photovoltaic systems, that have a foundational similarity to their stage four counterparts, with additional technical or operational complexities. Stage two consists of technologies with small-scale or pilot demonstrations but have yet to be commercialized, such as some energy storage alternatives and small modular nuclear reactors (SMR). Finally, stage one represents technologies that are still in the research and development phase but show promise for their potential utility applications.

15.2 Cost

Table 40: Estimated Relative Cost Rating for New Technologies

Technology Relative Cost			
Undefined	**High**	**Medium**	**Low**
Magnesium-ion batteries	Compressed air energy storage Flywheel energy storage Hydrogen Liquid air energy storage Municipal waste-to-energy Offshore wind Pumped hydro storage Small modular reactors	Biofuels Floating solar panels Lithium batteries Onshore wind Sodium-ion batteries Vanadium redox flow batteries	Land-based solar panels

The relative cost of technology, as identified in Table 40, is based on the average capital and operation and maintenance (O&M) costs associated with the systems, as well as production costs represented by levelized cost of energy (LCOE) or levelized cost of storage (LCOS). Among the technologies, capital and O&M costs tended to be higher for energy generation facilities than storage technologies due to the associated materials and greater component liability. The most significant exception would be solar generation, as the market cost for photovoltaic components has been decreasing rapidly due to technological development and economic investment. For battery components, O&M costs are minimal since the systems are enclosed and designed to require only occasional or annual maintenance, with few to no daily operators. Since it has been determined that biofuel production at scale is infeasible in Puerto Rico, the associated costs discussed in the report refer to fuel market prices. Market prices for biodiesel are comparable to those of conventional diesel, but additional costs associated with shipment to Puerto Rico are currently unconfirmed. Additionally, while Biofuels would be used within a traditional gas turbine or petroleum-burning facility using some Biofuel mix (B20 or B100), studies on the associated cost differences at these facilities are limited. Hydrogen costs depend on the equipment for electrolyzers needed for hydrogen production, the energy source for the electrolysis process, and the construction of a hydrogen combustion facility, which explains the relatively high cost.

15.3 Supply Chain

Table 41: Summary of Reliance on International Markets for Technology Components

Technology	Reliance on International Markets	Critical Producers and Manufacturers
Hydrogen	Medium	United States, China, Canada, Saudi Arabia, Australia
Biofuels	Low	United States, Brazil, Indonesia
Energy storage (non-battery)		
Pumped hydro storage	Low	Global Vendors
Flywheel ESS	Medium	China, United States, United Kingdom
LAES	Low	Global Vendors
CAES	Low	Global Vendors

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Technology	Reliance on International Markets	Critical Producers and Manufacturers
Small modular reactors (SMR)	Low	United States, Canada, France, Kazakhstan, Russia, Australia
Non-lithium batteries		
Sodium-ion	Low	Global Vendors
Magnesium-ion	High	China
Vanadium redox flow	High	China, Russia, South Africa, Brazil
Lithium batteries	High	China, Chile, Australia, Democratic Republic of Congo
Solar		
Solar- land	High	China
Solar- floating	High	China
Wind		
Wind- onshore	Medium	United States, China, India
Wind- offshore	High	China
Municipal waste-to-energy	Medium	China, Europe

In analyzing the supply chain for each technology, the emphasis was placed on determining the reliance on international trade markets, given Puerto Rico's relationship with the United States (see Table 41). Across all technologies, many standard components, such as pumps, heat exchangers, and basic raw and refined materials, can be procured from diverse global vendors and thus have minimal supply chain risks. Other technologies and associated components, such as biofuels or blades and towers for wind generation, have prominent domestic production but may also rely on other countries, such as China or Canada, resulting in a low/medium reliance designation. The technologies with high reliance designations include solar, for which China is the leading exporter of photovoltaic panels and polysilicon, and many electrochemical battery storage technologies that rely on raw materials such as lithium, vanadium, and magnesium.

15.4 Construction and Development

Table 42: Estimated Construction Times of Energy Generation and Storage Facilities

Estimated Facility Construction Time			
Undefined	**Short (1-3 Years)**	**Medium (3-5 Years)**	**Long (5+ Years)**
Liquid air energy storage Magnesium-ion batteries Sodium-ion batteries Vanadium redox flow batteries	Biofuels Hydrogen Land-based solar panels Lithium batteries Municipal waste-to-energy	Compressed air energy storage Floating solar panels Flywheel energy storage Onshore wind	Pumped hydro storage Small modular reactors Offshore wind

The construction timelines for each technology (Table 42) vary depending on site-specific conditions, local permitting processes, and the scale of the technology itself. Battery storage technologies generally have less land use requirements, and, given the adaptable site needs, they can be constructed quickly (two to three years). Conversely, technologies requiring vast amounts of land and capital cost, such as small modular reactors and pumped hydro storage, have the most extended construction timelines (five to 10 years). Many technologies also require particular site characteristics, such as compressed air energy storage, which ideally uses a pressurized underground cavern to store compressed air, or Municipal waste-to-energy, which needs to be sited closer to dense urban areas to limit transportation costs. These requirements may lead to extra time to account for environmental damage mitigation (as is the case for pumped hydro storage or compressed air energy storage [CAES]) or further permitting complications as the generation site is closer to urban areas.

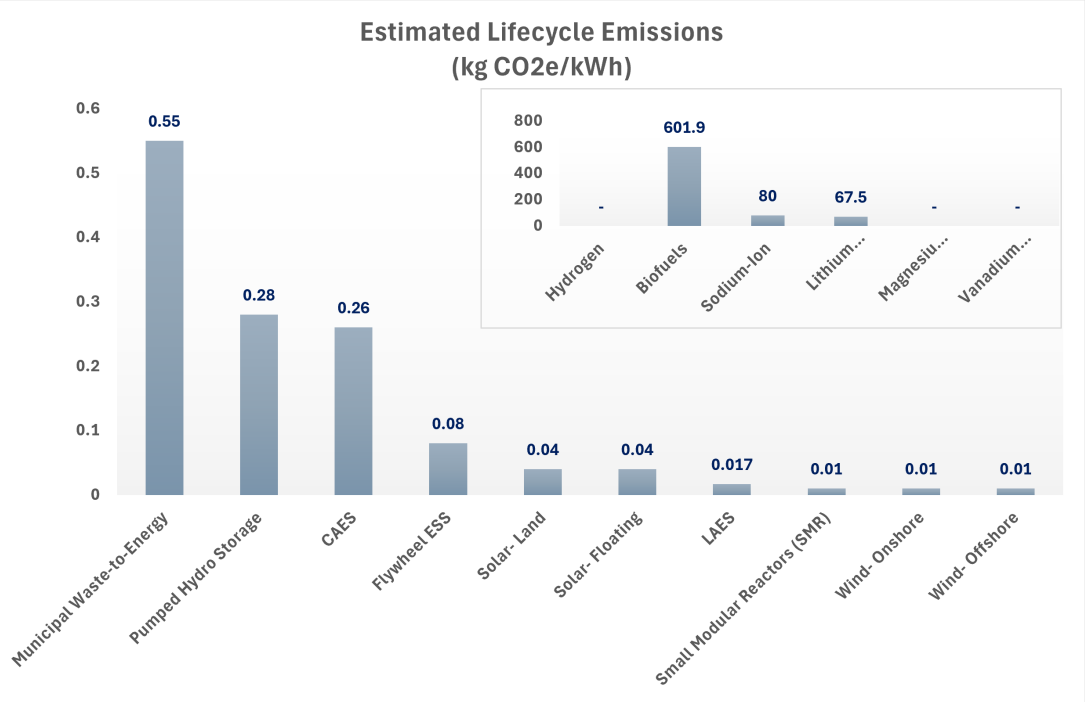
Finally, several technologies have an undefined construction timeline due to their early development stage. Biofuels were designated as a short-term timeline due to the potential for immediate use with B20 fuel mix. Though using a B100 fuel mix would require a retrofit of an existing facility, this level of construction would still likely qualify as a short construction timeline. Regarding hydrogen, electrolysis-based production also requires retrofitting existing facilities. However, cofiring hydrogen with liquefied natural gas (LNG) can be done with little to no retrofitting. The construction of hydrogen-specific combustion and generation facilities is in the early stages of development; therefore, no construction timeline estimates were included for this designation.

15.5 Sustainability

Table 43: Estimated Direct Land-Use Intensity Required to Build Each Type of Facility According to Technology, Measured in Land Area per Unit of Generation

Estimated Direct Land Use Intensity			
None	**Low**	**Medium**	**High**
Floating solar panels Offshore wind	Flywheel energy storage Lithium batteries Magnesium-ion batteries Small modular reactors Sodium-ion batteries Vanadium redox flow batteries	Biofuels Compressed air energy storage Hydrogen Liquid air energy storage Municipal waste-to-energy	Land-based solar panels Onshore wind Pumped hydro storage

Figure 21: Graph of Estimated Lifecycle Emissions for Each Technology



While looking at the sustainability of each technology, the best measures of comparison were direct land usage and lifetime greenhouse gas (GHG) emissions. Since direct land use, defined as electric production per unit of land excluding fuel production and transportation, can vary greatly depending on site-specific construction or developer decision-making, qualitative categories were used to compare how much land each technology would take up from the perspective of a utility-scale facility (Table 42). In this analysis, a “Medium” land use technology would have a direct footprint similar to a traditional combined cycle gas turbine facility (excluding land for gas drilling and pipelines). This category includes biofuels and hydrogen, using a retrofitted gas-firing facility for power generation. Based on this method,

all battery storage technologies are deemed low in land use intensity, with alternative storage technologies such as pumped hydro occupying much more land. Land-based photovoltaics and wind generation have very high direct land usage on a utility scale due to their low energy density. In contrast, small modular reactors (SMR) have a high-power density and, thus, a relatively smaller direct footprint. The two outliers in this category are floating solar panels and offshore wind, which do not occupy any land by design.

Regarding lifetime GHG emissions (see Figure 21), calculations include the equivalent CO_2 emissions during mining and fuel production, transportation, construction, and operation phases. As a result, technologies that rely on rare earth minerals, which depend on long transportation distances due to supply chain constraints, such as many of the non-lithium battery technologies, have higher lifetime emissions. Additionally, technologies requiring combustion for their energy production process, such as biofuels, hydrogen, municipal waste-to-energy, and CAES, have also increased lifecycle emissions. The lowest emission technologies include flywheel energy storage and wind generation. Hydrogen's value was reported to range from 0.7 to 4.5 kg CO2e per kg of H2, which could not be converted to the established unit of kg CO2e/kWh due to a lack of data regarding heat rates of hydrogen generation facilities.

15.6 Conclusion

Based on this analysis, it can be determined that while some technologies are premature in their market development, others have great potential for deployment in Puerto Rico. The viability of these technologies will be based heavily on the services they provide to the electric grid, weighed against their potential issues. Energy storage technologies have various uses and benefits to the grid, and the need for storage solutions will only heighten as generation is added to the system. This may lead to significant cost savings related to these technologies not captured in this report. This would apply to the various battery storage technologies, which have higher costs and reliance on international markets, yet offer modular implementation due to their small physical footprint and shorter construction times. Similarly, while municipal waste-to-energy facilities are not cost-effective, they would provide additional value by aiding in waste management, which is a primary concern on the Island.

Additionally, some technologies can take advantage of existing infrastructure in Puerto Rico to create value on currently underutilized land while saving on capital costs. Pumped hydro storage is a prime example of this, as several decommissioned hydroelectric generation facilities in Puerto Rico can provide significant capital cost savings and help circumvent the problematic siting requirements. Biofuels and hydrogen provide similar benefits, given that their production and combustion involve retrofitting existing operational facilities rather than newly constructed facilities.

When looking toward these technologies' future and potential value to Puerto Rico, emphasis should be placed on lithium battery energy storage system (BESS) technologies' economic and commercial development. As energy storage needs increase, along with the continued high demand for lithium batteries and reliance on international markets, viable technological competition will be essential. Likewise, as discussed in depth throughout this IRP Report, the maximization of potential photovoltaic and onshore wind generation will be key to Puerto Rico in the near and distant future. In addition, emphasis should be placed on biofuels, such as biodiesel, as they provide Puerto Rico's grid with

essential dispatchable capacity while supporting renewable energy goals. Their implementation is also facilitated by the existing grid infrastructure.

Resumen Ejecutivo

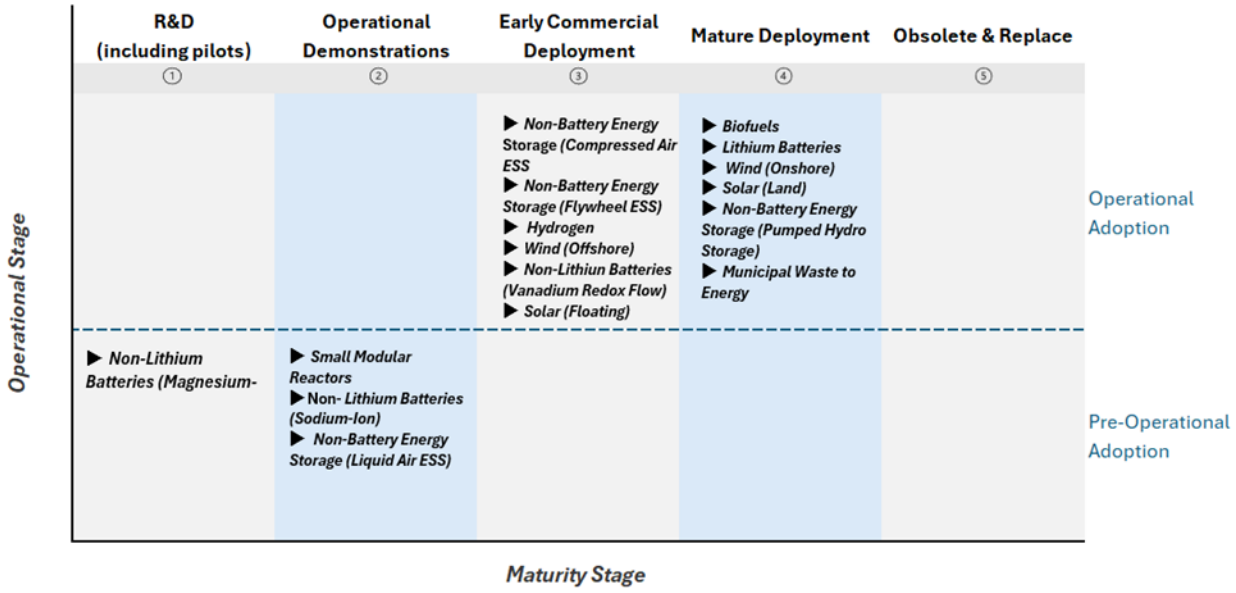
LUMA identificó varias tecnologías de generación de energía y evaluó su costo, madurez tecnológica y aplicabilidad en Puerto Rico para incluirlas en su Plan Integrado de Recursos. Explorar nuevos recursos y nuevas tecnologías es crucial para el futuro energético de Puerto Rico. En el Apéndice 5, se destacan varias tecnologías en distintas etapas de madurez y adaptación comercial. Dicho apéndice sirve como un resumen de los recursos y su potencial viabilidad para el sistema energético de Puerto Rico. El análisis se divide en cinco categorías principales de comparación: madurez de la tecnología, costo, cadena de suministro, periodo de construcción y sostenibilidad. Realizar un estudio comparativo de las tecnologías y los recursos energéticos que se pueden adoptar en Puerto Rico podría ayudar a identificar las soluciones de mayor impacto para el futuro cercano. La Tabla 1 muestra las tecnologías que se examinaron en este reporte:

Tabla 1: Nuevas opciones de recursos potenciales

Nuevas opciones de recursos potenciales			
Sistemas de almacenamiento sin utilizar baterías: Almacenamiento hidráulico por bombeo Almacenamiento de energía con volante de inercia Almacenamiento de energía con aire líquido Almacenamiento de energía con aire comprimido	**Sistemas de almacenamiento de energía utilizando baterías que no son de litio:** iones de sodio iones de magnesio batería de flujo de vanadio	**Hidrógeno**	**Sistemas marinos de energía eólica**
		Biocombustibles	**Sistemas terrestres de energía eólica**
		Reactores modulares pequeños	**Conversión de desperdicios municipales en energía**
	Baterías de litio	**Paneles solares acuáticos**	**Paneles solares terrestres**

15.7 Madurez de la tecnología y adopción global

Figura 1: Tecnologías de generación evaluadas



Las tecnologías incluidas en este reporte varían desde baterías de litio y sistemas terrestres de energía eólica desarrollados a un alto nivel de madurez hasta las que aún se encuentran en la etapa de investigación y desarrollo, como los sistemas de almacenamiento de energía utilizando baterías de iones de magnesio. Estas categorías de desarrollo están basadas en la implementación global de las tecnologías identificadas a escala de servicio público, al igual que la efectividad que cada una ha demostrado en términos de costo y confiabilidad (véase la Figura 1). La mayoría de las tecnologías se encuentra en las categorías de desarrollo comercial temprano y maduro (etapas tres y cuatro, respectivamente), lo cual indica que cuentan con al menos tres proyectos en todo el mundo que han demostrado su viabilidad económica. Muchos proyectos de la etapa tres son adaptaciones o modificaciones de tecnologías existentes de mayor madurez, como los sistemas marinos de energía eólica y sistemas fotovoltaicos acuáticos, los cuales comparten similitudes fundamentales con sus contrapartes de la etapa cuatro que tienen complejidades adicionales tanto técnicas como operacionales. La etapa dos consiste en tecnologías con demostraciones a pequeña escala o piloto que aún no se han comercializado, como algunas opciones de almacenamiento de energía y los reactores modulares pequeños. Finalmente, la etapa uno representa las tecnologías que aún se encuentran en la etapa de investigación y desarrollo y que, a su vez, cuentan con potencial para utilizarse a escala de servicio público

15.8 Costo

Tabla 2: Calificación de costo relativo estimado para nuevas tecnologías

Costo relativo por tecnología			
No definido	**Alta**	**Mediana**	**Baja**
Baterías de iones de magnesio	Sistema de almacenamiento con aire comprimido Sistema de almacenamiento con volante de inercia Hidrógeno Sistema de almacenamiento con aire líquido Conversión de desperdicios municipales en energía Sistemas marinos de energía eólica Almacenamiento hidráulico por bombeo Reactores modulares pequeños	Biocombustibles Paneles solares acuáticos Baterías de litio Sistemas terrestres de energía eólica Baterías de iones de sodio Baterías de flujo de vanadio	Paneles solares terrestres

El costo de cada tecnología, tal y como se indica en la Tabla 2, se basa en los costos capitales y de O&M asociados a cada sistema, al igual que en los costos de producción representados por el costo nivelado de energía (LCOE, por sus siglas en inglés) o el costo de almacenamiento nivelado (LCOS, por sus siglas en inglés). Entre las distintas tecnologías, los costos capitales y de O&M tendieron a ser más altos para las instalaciones de generación de energía que para las tecnologías de almacenamiento debido a los materiales asociados y a la mayor responsabilidad técnica y económica vinculada a sus componentes. La excepción más significativa es la generación de energía solar, ya que el costo de los componentes de un sistema fotovoltaico en el mercado ha estado disminuyendo rápidamente debido al desarrollo tecnológico y la inversión económica. Para los componentes de las baterías, los costos de O&M son mínimos, ya que se trata de sistemas cerrados y diseñados de tal forma que solo requieren mantenimiento ocasional o anual y pocos operadores diarios (incluso en algunos casos, no se requiere un operador). Ya que se ha determinado que la producción a escala de biocombustibles es inviable en Puerto Rico, el costo asociado que se discute en este reporte se refiere al precio del combustible en el mercado. El precio de mercado para el biocombustible es comparable al del diésel convencional, sin embargo, aún no se ha confirmado el costo adicional por importar este recurso a Puerto Rico. Además, si bien el biocombustible se incorporaría mezclando biocombustibles (B20 o B100) en instalaciones que utilizan turbinas de gas tradicionales o petróleo, son limitados los estudios sobre las diferencias de costos asociadas en estas instalaciones. Los costos del hidrógeno dependerán del equipo que se adquiera para los electrolizadores –fuente de energía encargada del proceso de electrólisis que, como resultado, produce hidrógeno– y de la construcción de instalaciones para la combustión de hidrógeno, lo cual explica el alto costo relativo de este recurso.

15.9 Cadena de suministro

Tabla 3: Resumen de la dependencia de los mercados internacionales para adquirir los componentes de cada tecnología

Tecnología	Dependencia de los mercados internacionales	Productores y manufactureros esenciales
Hidrógeno	Mediana	Estados Unidos, China, Canadá, Arabia Saudita, Australia
Biocombustibles	Baja	Estados Unidos, Brasil, Indonesia
Sistemas de almacenamiento (utilizando recursos que no son baterías)		
Sistemas de almacenamiento por bombeo hidráulico	Baja	Vendedores globales
Sistemas de almacenamiento con volante de inercia	Mediana	China, Estados Unidos, Reino Unido
Sistema de almacenamiento con aire líquido	Baja	Vendedores globales
Sistemas de almacenamiento con aire comprimido	Baja	Vendedores globales
Reactores pequeños modulares	Baja	Estados Unidos, Canadá, Francia, Kazajistán, Rusia, Australia
Baterías sin litio		
Iones de sodio	Baja	Vendedores globales
Iones de magnesio	Alta	China
Baterías de flujo de vanadio	Alta	China, Rusia, Sudáfrica, Brasil
Baterías de litio	Alta	China, Chile, Australia, República Democrática del Congo
Solar		
Sistema de energía solar-terrestre	Alta	China
Sistema de energía solar-acuático	Alta	China
Eólica		
Sistemas terrestres de energía eólica	Mediana	Estados Unidos, China, India
Sistemas marinos de energía eólica	Alta	China

Tecnología	Dependencia de los mercados internacionales	Productores y manufactureros esenciales
Conversión de desperdicios municipales en energía	Mediana	China, Europa

Al analizar las cadenas de suministro para cada tecnología, se enfatizó el determinar la dependencia de los mercados de intercambio internacionales debido a la relación de Puerto Rico con Estados Unidos (véase Tabla 3). Muchos componentes estándar de estas tecnologías, como sistemas de bombeo, intercambiadores de calor y materias primas básicas y refinadas pueden adquirirse a través de una diversidad de vendedores globales y, por ende, es mínimo el riesgo relacionado a la cadena de suministro. Otras tecnologías y sus componentes, como los biocombustibles o las hojas y las torres que se requieren para la generación de energía eólica cuentan con una producción doméstica prominente, pero también podrían depender de otros países como China o Canadá y, por consiguiente, se les designa un nivel de dependencia bajo o mediano. Entre las tecnologías con niveles altos de dependencia se encuentran la solar, para la cual China es el exportador líder de paneles fotovoltaicos y polisilicio, y muchas de las tecnologías de almacenamiento que utilizan baterías electroquímicas, las cuales dependen de materia prima como litio, vanadio y magnesio.

15.10 Construcción y desarrollo

Tabla 4: Tiempo estimado de construcción para instalaciones de generación y almacenamiento de energía

Tiempo estimado para la construcción de instalaciones			
Sin definir	**Corto (1-3 años)**	**Mediano (3-5 años)**	**Largo (5+ años)**
Sistemas de almacenamiento con aire líquido; Baterías de iones de magnesio; Baterías de iones de sodio; Baterías de flujo de vanadio	Biocombustibles; Hidrógeno; Paneles solares terrestres; Baterías de litio; Conversión de desperdicios municipales en energía	Sistemas de almacenamiento con aire comprimido; Paneles solares acuáticos; Sistemas de almacenamiento con volante de inercia; Sistemas terrestres de energía eólica	Sistemas de almacenamiento por bombeo hidráulico; Reactores modulares pequeños; Sistemas marinos de energía eólica

Los plazos de construcción para cada tecnología (véase Tabla 4) varían dependiendo las condiciones específicas de cada localidad, los procesos locales para la obtención de permisos y el volumen. Por lo general, las tecnologías de almacenamiento utilizando baterías requieren menos terreno y, dado que se pueden adaptar al sitio según las necesidades, el tiempo de construcción es corto (entre dos y tres años). Por otro lado, las tecnologías que requieren terrenos vastos y gran capital, como los reactores modulares pequeños y el almacenamiento por bombeo hidráulico, precisan más tiempo de construcción (de cinco a 10 años). Muchas tecnologías necesitan sitios con características específicas, como la tecnología de almacenamiento de energía con aire comprimido –la cual usualmente se ubica en una caverna subterránea presurizada que almacena aire comprimido–, o la de conversión de desperdicios municipales en energía –sistema que requiere estar ubicado cerca de áreas urbanas densas para limitar los costos de transporte–. Estos requisitos podrían conllevar un tiempo adicional para mitigar el daño

ambiental (como ocurre con el almacenamiento por bombeo hidráulico o con el almacenamiento de energía utilizando aire comprimido) o por complicaciones en cuanto a permisos en la medida que las instalaciones de generación estén más cerca de zonas urbanas.

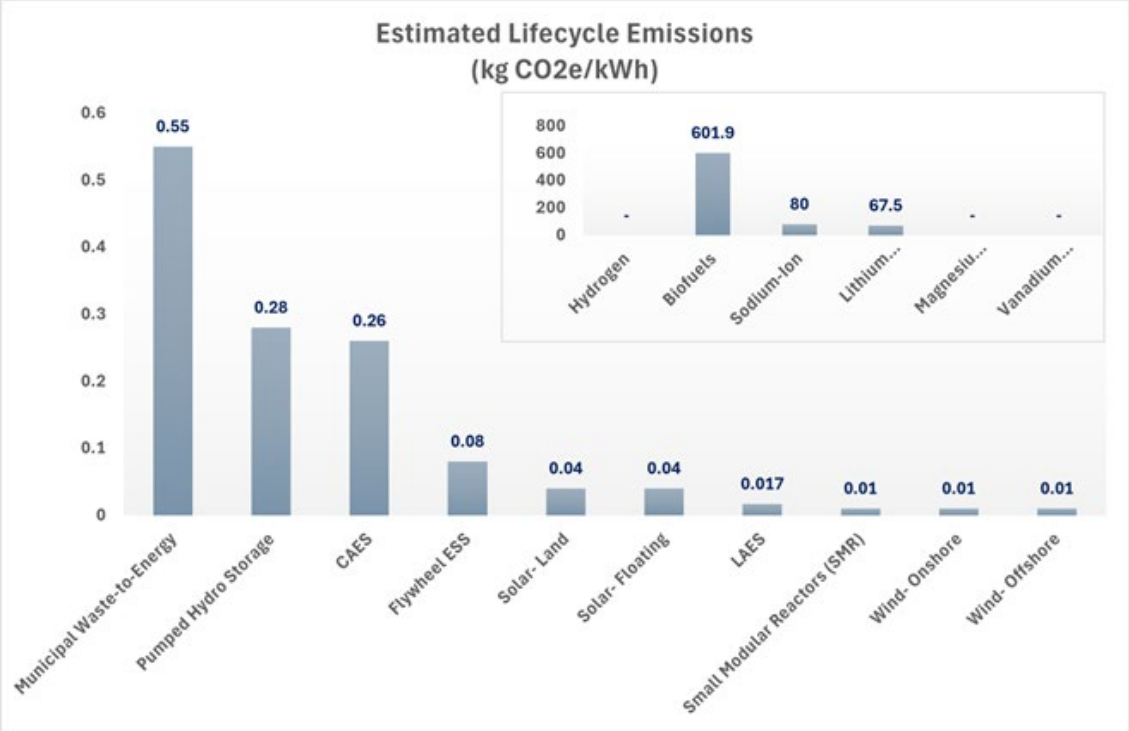
Finalmente, varias tecnologías no tienen plazos definidos de construcción, ya que se encuentran en etapas tempranas de desarrollo. Las instalaciones que utilizarían biocombustibles (con mezcla de combustible B20) se clasificaron bajo plazos de construcción cortos, ya que cuentan con alto potencial de uso inmediato. Aunque utilizar una mezcla de combustible B100 requeriría la modernización de instalaciones existentes, probablemente dicha modernización se clasificaría bajo un plazo de construcción corto. En cuanto al hidrógeno, su producción mediante la electrólisis también requeriría la modernización de instalaciones. No obstante, la combustión conjunta de hidrógeno con gas natural licuado puede realizarse con poca o ninguna modernización. La construcción de instalaciones para la combustión y generación de hidrógeno aún se encuentra en etapas tempranas de desarrollo, por lo que no se utilizaron estimados de tiempo de construcción para designarle una categoría.

15.11 Sostenibilidad

Tabla 5: Estimado del uso de terreno estrictamente necesario para la construcción de cada tipo de instalación según la tecnología, medido como superficie por unidad de generación de energía

Estimado del uso de terreno estrictamente necesario			
Ninguno	**Bajo**	**Mediano**	**Alto**
Paneles solares acuáticos; Sistemas marinos de energía eólica	Sistema de almacenamiento con volante de inercia; Baterías de litio; Baterías de iones de magnesio; Reactores modulares pequeños; Baterías de iones de sodio; Baterías de flujo de vanadio	Biocombustibles; Sistemas de almacenamiento con aire comprimido; Hidrógeno; Sistemas de almacenamiento con aire líquido; Conversión de desperdicios municipales en energía	Paneles solares terrestres; Sistemas costeros-terrestres de energía eólica; Sistemas de almacenamiento por bombeo hidráulico

Figura 2: Gráfica de emisiones estimadas de acuerdo con el ciclo de vida de cada tecnología



Al estudiar la sostenibilidad de cada tecnología, las mejores medidas de comparación fueron el uso directo de terreno y las emisiones de gases de invernadero (GHG, por sus siglas en inglés). Ya que el uso directo de terreno –que se define como producción eléctrica por unidad de terreno excluyendo la producción y el transporte de combustible– puede variar de manera considerable dependiendo de la construcción de las instalaciones o la toma de decisiones de los desarrolladores, se utilizaron categorías cualitativas para comparar cuánto terreno ocuparía cada tecnología desde la perspectiva de una estructura de servicio público (Tabla 5). En este análisis, una tecnología con uso de terreno "mediano" dejaría una huella similar a la de unas instalaciones de turbinas de gas de ciclo combinado (excluyendo el terreno para extracción de gas y los conductos). Los biocombustibles y el hidrógeno serían ejemplos de esta categoría, pues utilizarían instalaciones modernizadas de combustión de gas para generar electricidad. Basándose en este método, todas las tecnologías de almacenamiento en baterías están catalogadas como de baja intensidad en uso directo de terreno, y las otras tecnologías, como el almacenamiento hidráulico por bombeo, son las que más terreno ocuparían. Los sistemas fotovoltaicos terrestres y los de generación eólica utilizan mucho terreno a escala de servicio público debido a su baja densidad energética. En cambio, los reactores modulares pequeños (SMR, por sus siglas en inglés) cuentan con alta densidad energética, por ende, la huella que dejan es relativamente menor. Las dos excepciones en esta categoría son los paneles fotovoltaicos acuáticos y los sistemas marinos de energía eólica, los cuales, por diseño, no ocupan terreno en absoluto.

En cuanto a las emisiones de gas de invernadero (véase Figura 2), los cálculos incluyen las emisiones equivalentes de CO_2 durante las fases de minería, producción y transporte de combustible, construcción y operación. Por consecuencia, las tecnologías que requieren el uso de elementos críticos (minerales de tierras raras), los cuales dependen de distancias largas de transporte debido a las limitaciones en las cadenas de suministro, como las baterías que no son de litio, producen mayores emisiones durante sus

ciclos de vida. Del mismo modo, las tecnologías que requieren combustión para su proceso de producción de energía, como los biocombustibles, el hidrógeno, la conversión de desperdicios municipales en energía y los sistemas de almacenamiento con aire comprimido, también producen mayores emisiones durante sus ciclos de vida. Las tecnologías con menos emisiones son las de almacenamiento con volante de inercia y la generación eólica. Se ha reportado que el valor del hidrógeno fluctúa entre 0.7 hasta 4.5 kg CO_2e por kg de H2, el cual no podría convertirse en una unidad establecida de kg CO_2e/kWh debido a la falta de datos relacionados a los rangos de calor en las instalaciones de generación de hidrógeno.

15.12 Conclusión

Basado en este análisis, se puede determinar que, mientras algunas tecnologías son prematuras en su desarrollo dentro del mercado, otras tienen un gran potencial para su implementación en Puerto Rico. La viabilidad de estas tecnologías dependerá en gran medida de los servicios que ofrezcan a la red eléctrica, en comparación con los posibles inconvenientes que puedan presentar. Las tecnologías de almacenamiento de energía tienen varios usos y beneficios para la red, y la necesidad de soluciones de almacenamiento continuarán aumentando a medida que se añada generación al sistema. Esto podría conllevar ahorros significativos en cuanto a costos relacionados a estas tecnologías, los cuales no se capturan en este reporte. Este sería el caso de las distintas tecnologías de almacenamiento en baterías, las cuales tienen costos más altos y dependen de mercados internacionales, no obstante, permiten una implementación modular debido a que dejan una huella física más pequeña, y conllevan menos tiempo de construcción. Del mismo modo, si bien las instalaciones de conversión de desperdicios municipales en energía no son efectivas en función de los costos, aportarían un valor adicional para el manejo de desperdicios, lo cual es una de las preocupaciones principales en la Isla.

Además, algunas tecnologías pueden aprovechar la infraestructura existente en Puerto Rico para generar valor a los terrenos subutilizados, al tiempo que ahorran en costos capitales. El almacenamiento de energía hidroeléctrica por bombeo es un excelente ejemplo de esto, ya que varias instalaciones de generación hidroeléctricas que están en desuso en Puerto Rico pueden brindar importantes ahorros en costos de capital y ayudar a sortear el problema de los requisitos de ubicación. Los biocombustibles y el hidrógeno proveen beneficios similares, ya que su producción y combustión solo requieren la modernización de instalaciones existentes en lugar de construir instalaciones nuevas.

Al analizar el futuro de estas tecnologías y su potencial valor para Puerto Rico, es necesario priorizar el desarrollo económico y comercial de las tecnologías de sistemas de almacenamiento de energía en baterías (BESS, por sus siglas en inglés), en particular cualquier demostración piloto en el ámbito del servicio público. A medida que aumente la necesidad de almacenar energía, junto con la alta demanda de baterías de litio y la dependencia en los mercados internacionales, será esencial una competencia tecnológica viable. Del mismo modo, y según se discute a profundidad a través de este Reporte del Plan Integrado de Recursos, será clave maximizar el potencial de generación de energía mediante sistemas terrestres fotovoltaicos y eólicos para Puerto Rico de cara al futuro.

16.0 *New Resource Option: Hydrogen*

16.1 Description

While fossil fuels, such as oil and gas, have long been the dominant energy source, the global commitment to reducing carbon emissions has spurred a rapid shift towards renewable energy sources. Over 100 countries have pledged to achieve net-zero carbon emissions, and hydrogen is emerging as a promising alternative to traditional fossil fuels.

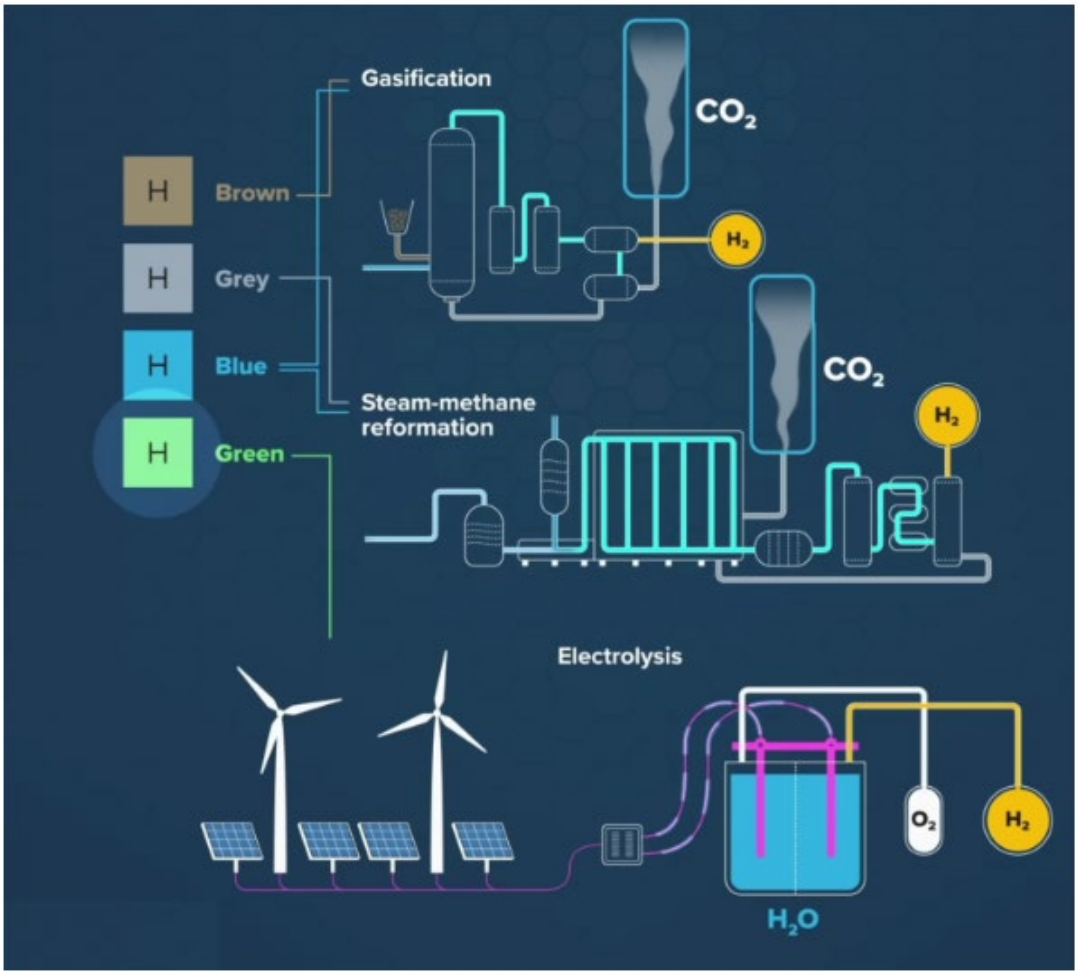
Hydrogen is the most abundant element in the universe [13] It is a lightweight gas that does not contain carbon or emit carbon or carbon compounds (i.e., a substance that contains carbon) when combusted or used in a fuel cell. A key component of greenhouse gas is carbon dioxide (CO_2), which is emitted when fossil fuels are combusted. This lack of carbon makes hydrogen a desirable option for clean energy generation. However, hydrogen is not a readily available fuel source on Earth. It needs to be extracted or produced from other materials.

Hydrogen can be classified into four primary categories based on its production method:

- **Brown hydrogen***:* Produced from coal through gasification, brown hydrogen is associated with significant carbon dioxide emissions.
- **Grey hydrogen:** Currently accounting for most global hydrogen production, grey hydrogen is extracted from natural gas via steam methane reforming. Like brown hydrogen, grey hydrogen also releases substantial amounts of carbon dioxide.
- **Blue hydrogen:** Derived from fossil fuels, blue hydrogen incorporates carbon capture and storage technologies to reduce carbon emissions. Due to its reliance on fossil fuels, it is still considered a transitional fuel.
- **Green hydrogen:** Produced through electrolysis, green hydrogen is a clean energy source when the electricity used to power the electrolyzer comes from renewable sources such as solar or wind. This method offers a carbon-neutral alternative to traditional hydrogen production. See Figure 22.

[13] U.S. Energy Information Administration (EIA). (2023). Hydrogen explained. *U.S. Energy Information Administration.* https://www.eia.gov/energyexplained/hydrogen/

Figure 22: Electrolysis Process for Green Hydrogen[14]



This report will focus on green hydrogen, a promising solution to decarbonize the energy sector. Specifically, this section explores its application for Puerto Rico in two key areas:

- **Utility-scale power generation**: Green hydrogen can be integrated into existing power plants to replace fossil fuels, reducing greenhouse gas emissions and providing a more sustainable energy source.
- **Energy storage**: Green hydrogen can store excess renewable energy, such as solar or wind power, for later use in utility-scale generation when demand is high or when renewable energy sources are intermittent. This helps to balance the grid and improve the reliability of renewable energy systems.

16.2 Technology Maturity

Hydrogen technologies in production and end-use applications are in the early stages of commercial deployment. As the global hydrogen market expands, substantial scale-up will be necessary. Hydrogen plays a minimal role in the power sector, contributing to less than 0.2% of global electricity generation.

[14] See: https://www.silicontocarbon.com/blog/atomic-punk

Moreover, much of this hydrogen is not used in its pure form but as part of blends with other gases, such as natural gas. The anticipated growth of hydrogen technologies presents a significant opportunity for the energy sector. However, achieving full maturity in power generation will require further research and development, expansion of hydrogen-related policies, and greater stakeholder engagement.[15]

Due to its versatility and ability to store and produce firm, dispatchable, and carbon-free energy, hydrogen is gaining attention in the transportation and energy generation sectors. Its transition to widespread use will occur in multiple phases, each marked by increasing technological and market maturity.

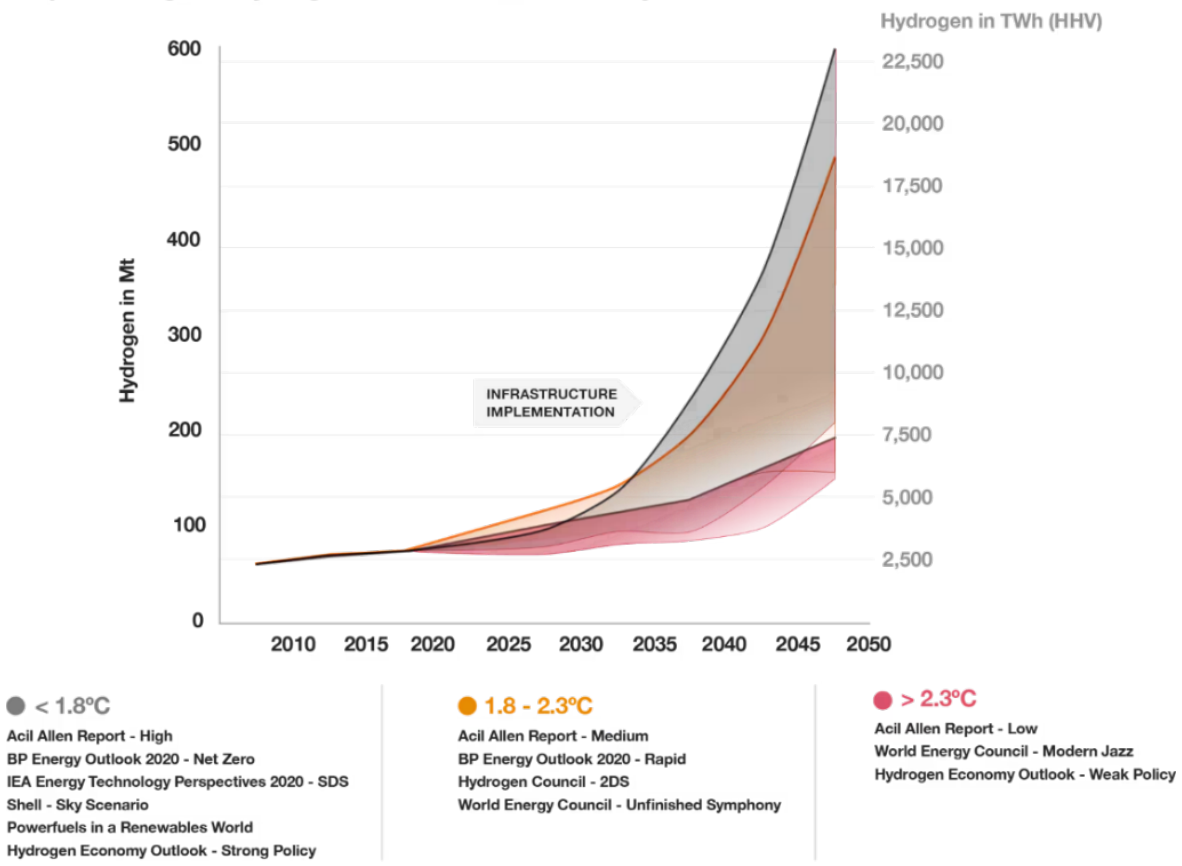
In the short term (2025 to 2030), hydrogen for power generation is expected to grow in demonstration projects, alongside limited commercial deployments. These early projects will likely have higher costs due to the current expense of hydrogen production. However, they will serve as key milestones, attracting early investors, establishing critical infrastructure, and laying the foundation for hydrogen's development as a sustainable energy solution.[16]

In the medium term (2030 to 2040), cost reductions and infrastructure expansion from previous years are expected to drive significant growth in the hydrogen market. This phase will likely see increased adoption of hydrogen fuel cells for medium- and heavy-duty vehicles and expanded use in distributed generation plants for power production.[17]

In the long term (beyond 2040), hydrogen is expected to become widespread due to declining production, transportation, and utilization costs. Figure 23 illustrates a hydrogen demand assessment through 2050. As such, hydrogen will play a key role in decarbonizing the energy sector, including power plants and integrated energy systems.[18]

[15] Energy International Renewable Agency (IRENA). (2024). Green hydrogen strategy: A guide to design. https://www.irena.org/Publications/2024/Jul/Green-hydrogen-strategy-A-guide-to-design.
[16] International Renewable Energy Agency (IRENA). (2024). Green hydrogen strategy: A guide to design. https://www.irena.org/Publications/2024/Jul/Green-hydrogen-strategy-A-guide-to-design.
[17] 100RE Lab. (2023). Green hydrogen market: Potentials and challenges. https://100re-map.net/green-hydrogen-market-potentials-and-challenges/.
[18] PwC. (n.d.). The green hydrogen economy: Predicting the decarbonization agenda of tomorrow. https://www.pwc.com/gx/en/industries/energy-utilities-resources/future-energy/green-hydrogen-cost.html.

Figure 23: Range of Hydrogen Demand Assessment by 2050



Despite hydrogen's potential, the U.S. Department of Energy (DOE) published a 2024 report studying the viability of a 100% renewable electricity system in Puerto Rico, which did not include hydrogen for power generation.[19] The report concluded that local hydrogen production was too expensive to be viable in any assessed scenario. These conclusions underscore the importance of using realistic, region-specific cost assumptions when modeling energy technologies.[20] However, as hydrogen and other emerging technologies reach commercial-scale deployment, costs are expected to decline. With advancements in production, infrastructure, and technology, hydrogen could become a more cost-effective option for power generation in the future.

16.3 Cost

The cost of hydrogen production largely depends on the technology and the price of the energy source used to produce it, which typically has significant regional differences.

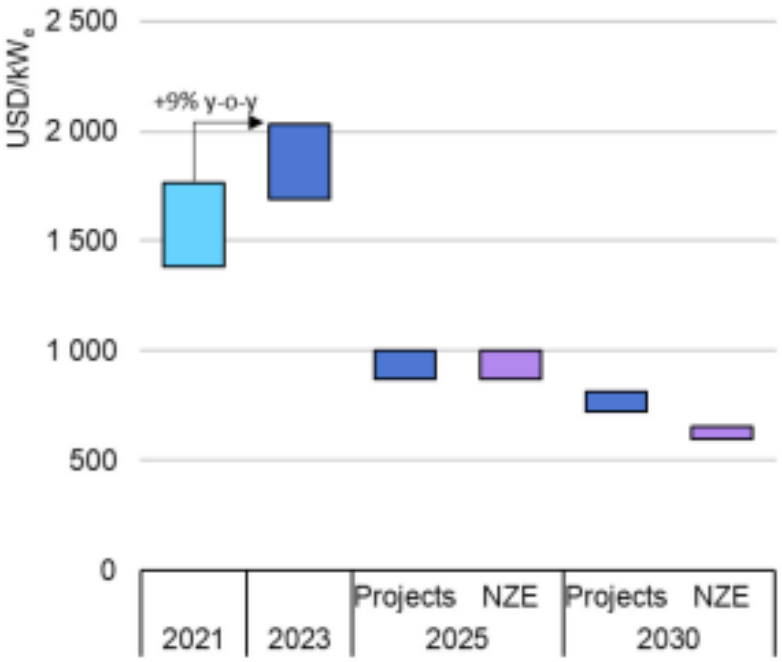
The cost of hydrogen produced by electrolysis is driven by the capital cost of electrolyzers and the electricity used to power these electrolyzers. The capital cost of electrolyzers ranges between USD 1700/kW and USD 2000/kW for alkaline and Proton Exchange Membrane (PEM) electrolyzers,

[19] National Renewable Energy Laboratory (NREL). (2024). Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100). https://www.nrel.gov/docs/fy24osti/88384.pdf

[20] Wang, S. (2024). A tale of two 100% renewable Puerto Rico Studies. *The Breakthrough Institute*. https://thebreakthrough.org/issues/energy/a-tale-of-two-100-renewable-puerto-rico-studies

respectively. This cost includes the equipment, plant balancing, engineering, procurement, and production costs of electrolyzers. It should be considered that the capital cost of electrolyzers has increased in recent years due to increases in materials and labor costs. Although based on the envisioned deployment of electrolyzers in the next decade, capital costs are expected to decrease due to a significant increase in production volumes, potentially reducing capital costs by 60-70% by 2030.[21] Figure 24 illustrates the forecasted electrolyzer capital cost reductions.

Figure 24: Evolution of Electrolyzers CAPEX



Beyond the capital costs of electrolyzers, operation, and maintenance (O&M) costs, as well as power and compression costs, must be considered when assessing the price of hydrogen produced by electrolysis. O&M costs are estimated at 2–4% of capital costs per year. The most critical factor, however, is the cost of electricity required to operate the electrolyzers, which varies depending on the energy source.[22]

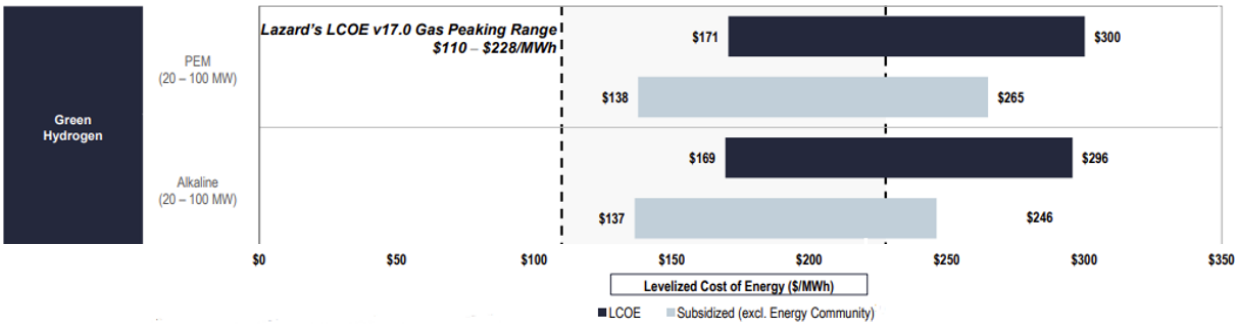
Considering capital costs, O&M, and the use of renewable electricity, the 2020 production cost for green hydrogen was approximately USD 7.5/kg H_2. The DOE targets to reduce these costs to USD 2/kg H_2 by 2026 and to USD 1/kg H_2 by 2031.[23]

Given this, the most realistic application of hydrogen for power generation in the near to mid-term will likely involve using natural gas-hydrogen blends. Based on an analysis prepared by Lazard on the

[21] International Energy Agency (IEA). (2023). Global Hydrogen Review 2023. https://www.iea.org/reports/global-hydrogen-review-2023#overview
[22] Monitor Deloitte. (2021). Fueling the future of mobility: hydrogen electrolyzers. https://www2.deloitte.com/content/dam/Deloitte/jp/Documents/global-business-support/jp-gbs-fueling-the-future-of-mobility-hydrogen-electrolyzers.pdf
[23] Center for Sustainable Systems, University of Michigan. (2024). Hydrogen factsheet [Pub. No. CSS23-07]. https://css.umich.edu/publications/factsheets/energy/hydrogen-factsheet

levelized cost of energy (LCOE) of hydrogen, using a blend with hydrogen comprising 25% of the mixture in a natural gas-firing combustion turbine is anticipated to cost $169 to $300 per MWh.[24]

Figure 25: Hydrogen Levelized Cost of Energy[25]



16.4 Supply Chain

Hydrogen, while one of the most abundant elements, faces significant challenges in establishing a robust supply chain, similar to the early development of natural gas infrastructure. As hydrogen is expected to play a key role in achieving net-zero emissions, its demand will grow four to six times by 2050. Despite this, reducing the cost of hydrogen production and delivery remains a critical obstacle, as these costs vary significantly across different regions.

Hydrogen production costs can differ dramatically depending on geographic location. In regions such as Qatar, Chile, Australia, and China, where hydrogen demand is relatively low, production costs are as low as $1 per kilogram. Conversely, in high-demand areas such as Germany, Japan, and South Korea, hydrogen production can reach up to $5 per kilogram, five times more expensive than the cheapest markets. This disparity underscores the need for a globally integrated supply chain to facilitate the movement of hydrogen from regions of surplus to those with high demand.[26]

Today's largest hydrogen producers are China, North America, and the Middle East, where most of the production is for domestic consumption. These regions primarily transport hydrogen through pipelines, mimicking the approach used for natural gas. However, due to hydrogen's high reactivity and the need for specialized materials in pipeline construction, the cost of transporting hydrogen through pipelines is higher compared to other methods.[13]

Transporting hydrogen presents several options, each with its advantages and challenges. Hydrogen can be transported via pipelines, road, rail, or maritime transport in high-pressure tanks, or as liquid hydrogen in cryogenic tanks. Liquefying hydrogen requires substantial energy input and expensive infrastructure. Another option is to transport hydrogen as ammonia, which is easier to move and can later be converted back into hydrogen for use in fuel cells or other applications.[27] This versatility in

[24] Lazard (2024). Levelized Cost of Energy + Report
[25] Lazard (2024). Levelized Cost of Energy + Report
[26] McKinsey & Company. (2022). *GII 2022: Delivering the global hydrogen supply chain* [Video]. YouTube. https://www.youtube.com/watch?v=esU7d9gjHU4
[27] Azadnia, A. H., McDaid, C., Andwari, A. M., & Hosseini, S. E. (2023). Green hydrogen supply chain risk analysis: A European hard-to-abate sectors perspective. *Renewable and Sustainable Energy Reviews*, 182, 113371. https://www.sciencedirect.com/science/article/pii/S1364032123002289)8ffbdff616a3&sid=ec63c9a962bdc2496c18c7c6693ae8348ec1gxrqa&type=client&tsoh=d3d3LnNjaWVuY2VkaXJlY3QuY29t&ua=16145b03500152065657&rr=8c7c1d515ac1428e&cc=pr

transportation methods reflects the complexity of hydrogen's global supply chain, which must consider local infrastructure, distances, and the quantity of hydrogen to be delivered.

Much of global hydrogen consumption relies on imports from major consumers like Europe, Japan, and South Korea. These countries heavily depend on hydrogen imports from Northern Africa, the Middle East, Latin America, and Australia. Around half of the imported hydrogen is transported via pipelines, while the other half is shipped, often as derivative products like ammonia or liquid hydrogen.[13]

According to McKinsey, reducing the cost of the hydrogen supply chain by 40% by 2030 will require an investment of approximately $950 billion.[13] Scaling up hydrogen technology, particularly electrolyzer production, will be key to driving down costs. Electrolyzer capacity must scale up four times faster than the growth seen in solar PV manufacturing to achieve this. As the technology scales, mass production will allow for design optimization, automation, and industrialization of electrolyzer assembly, potentially reducing costs by 60% within the next five years.[13]

Beyond production, delivering hydrogen at scale presents its challenges. Large-scale hydrogen projects must be optimized to ensure that designs are efficient in terms of cost and sustainability.[13]

The green hydrogen supply chain faces several risks that must be carefully managed to ensure successful implementation. The most significant barrier remains high capital investment for production and delivery technologies.[14] Additionally, there is a lack of electrolyzer capacity and insufficient policy and regulatory frameworks to support hydrogen's growth. Although hydrogen has potential substitutes, like fossil fuels and other forms of hydrogen (blue, grey, and brown), these are not considered significant threats due to the global focus on decarbonization efforts.

Further compounding these risks is the underdeveloped infrastructure for storing and transporting hydrogen. As hydrogen needs increase across multiple industries, storage and transportation will become bottlenecks unless adequate investment is made into expanding capacity.[14]

Building a sustainable hydrogen supply chain requires substantial investment and policy support. Increasing electrolyzer production, improving delivery infrastructure, and optimizing transportation methods will reduce costs and enable hydrogen delivery from surplus regions to high-demand areas. The next decade will be critical in overcoming these challenges, as hydrogen is poised to become a cornerstone of global decarbonization efforts.

16.5 Construction and Development

Developing and constructing hydrogen technologies is essential to supporting the widespread use of hydrogen for power generation. Two key focus areas are hydrogen production technologies, and the adaptation of combustion turbines to use hydrogen as a fuel.

Green hydrogen produced by electrolysis, which can result in zero greenhouse gas emissions, should be used to reduce the emissions of the current power generation system.[28] Electrolyzers are already widely used in industry to produce chlorine and sodium hydroxide. The deployment of electrolyzers for dedicated hydrogen production accelerated in the late 2010s, achieving a total 257 MW capacity worldwide. Interest in this technology has increased over the past years, and by the end of 2023, global

[28] U.S. Department of Energy. (n.d.). Hydrogen Production: Electrolysis. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.

electrolysis capacity had reached almost three gigawatts (GW). Based on current projects under development, global electrolysis capacity has the potential to reach 170-365 GW by 2030.[29]

Regarding turbine adaptation, manufacturers are advancing the development of combustion turbines, specifically designed to burn hydrogen fuel for power. While these combustion turbines are still developing, significant progress has been made. Some manufacturers have successfully developed turbines capable of operating on natural gas and hydrogen blends, offering a transitional solution as the technology matures. Furthermore, next-generation fuel-flexible power plants are being designed to run on 100% hydrogen and natural gas, offering greater flexibility and sustainability in power generation.[30]

Based on the available information on installed gas turbines and their maximum hydrogen blending shares, which range from 10% to 100% depending on the gas turbine design, the hydrogen-fired capacity from existing gas turbines amounts to more than 70 GW globally.[31] These turbines are a key milestone in the transition towards cleaner energy sources. They are crucial in reducing carbon emissions and supporting the increasing use of renewable energy.

16.6 Operation

When talking about the use of hydrogen for energy generation, the pathways of hydrogen production should be considered. The primary methods for producing hydrogen are:

- **Gasification:** A process that converts coal or biomass into syngas using heat. The syngas is then cooled and cleaned to remove impurities and sent to a shift reactor, where carbon monoxide (CO) reacts with steam to produce additional hydrogen (H2) and carbon dioxide (CO_2). As such, the syngas consists primarily of H2 and CO_2. Once the gas has undergone the shift reaction, it is separated into hydrogen and carbon dioxide streams. After purification, the hydrogen is ready for used.[32]

- **Steam methane reforming:** In this process, methane from natural gas reacts with steam at high temperatures to produce a mixture of carbon monoxide (CO) and hydrogen (H_2). The carbon monoxide then reacts with additional steam in the presence of a catalyst, generating more hydrogen and carbon dioxide (CO_2) in what is known as the water-gas shift reaction. SMR is currently the least expensive method for producing hydrogen, costing approximately $1–2 per kilogram of H_2, but it emits about 7–10 kilograms of CO_2 for every kilogram of hydrogen produced.[33]

- **Electrolysis:** In this process, electricity is used to split water into hydrogen and oxygen. It takes place in electrolyzers. Hydrogen produced by this method could result in zero greenhouse gases if the electricity used comes from renewable sources. However, the current grid mix is not ideal for electrolysis as, in the U.S., the CO_2 intensity of hydrogen produced by electrolysis is approximately 20-25 kg CO_2/kgH2. Production costs are higher ($7.5/kg$H_2$ for green hydrogen). Electrolysis is a

[29] International Energy Agency (IEA). (n.d.). Electrolyzers. https://www.iea.org/energy-system/low-emission-fuels/electrolysers.
[30] Wärtsilä Energy. (n.d.). Hydrogen-ready power plant solutions. https://www.wartsila.com/energy/sustainable-fuels/hydrogen-power-plant
[31] International Energy Agency (IEA). (2023). Global Hydrogen Review 2023. https://www.iea.org/reports/global-hydrogen-review-2023#overview
[32] U.S. Department of Energy. (n.d.). Hydrogen Production: Biomass Gasification. https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification
[33] Student Energy. (2021). Steam Methane Reforming. https://studentenergy.org/production/steam-methane-reforming/.

leading hydrogen production pathway, and costs are expected to be reduced to \$1-2/kgH_2 in the next decade. [34, 35]

Electrolysis is the most promising option for producing carbon-free energy from renewable resources. Electrolyzers consist of an anode and a cathode, separated by an electrolyte. Depending on the type of electrolyte material, there are several types of electrolyzers:

- **Polymer Electrolyte Membrane (PEM):** Electrolyte is a solid specialty plastic material. In this type of electrolyzer, water reacts at the anode to form oxygen and positively charged hydrogen ions. Meanwhile, the electrons flow through an external circuit, and the ions move across the PEM to the cathode. After that, the hydrogen ions combine with the electrons from the external circuit to form hydrogen gas.[36]

- **Alkaline electrolyzers:** These electrolyzers transport hydrogen ions from the cathode to the anode through the electrolyte, generating hydrogen on the cathode side. This type of electrolyzer is mature and commercially available. Newer alternatives using solid alkaline exchange membranes show promising results at the laboratory scale.[37]

- **Solid oxide electrolyzers:** These electrolyzers use solid ceramic materials as the electrolyte. In these electrolyzers, steam at the cathode combines with the external circuit electrons to form hydrogen gas and negatively charged oxygen ions. These ions pass through the solid ceramic membrane, react at the anode to form oxygen gas, and generate electrons for the external circuit. These electrolyzers operate at high temperatures and can use heat from various sources to decrease the electricity needed to produce hydrogen from water.[38]

Once hydrogen is produced, it can be utilized in existing gas turbine power plants by co-firing it with natural gas or as a standalone fuel. As previously discussed, many turbines can operate on a mixture of natural gas and hydrogen, allowing for a gradual integration of hydrogen while maintaining operational reliability. In addition, it is expected that other plants can be designed or retrofitted to operate entirely on hydrogen. This transition would eliminate the CO_2 emissions associated with the combustion process, making it an important contributor to achieving net-zero emissions in power generation. [39, 40]

16.7 Sustainability

Green hydrogen is rapidly gaining attention as a key player in the global transition toward sustainable energy. Its environmental impact largely hinges on the renewable energy sources used in its production, particularly for the energy-intensive electrolysis process that separates hydrogen from water. The choice

[34] Center for Sustainable Systems, University of Michigan. (2024). Hydrogen factsheet [Pub. No. CSS23-07]. https://css.umich.edu/publications/factsheets/energy/hydrogen-factsheet
[35] Student Energy. (2021). Steam Methane Reforming. https://studentenergy.org/production/steam-methane-reforming/
[36] U.S. Department of Energy. (n.d.). Hydrogen Production: Electrolysis. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis
[37] U.S. Department of Energy. (n.d.). Hydrogen Production: Electrolysis. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis
[38] U.S. Department of Energy. (n.d.). Hydrogen Production: Electrolysis. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis
[39] Goldmeer, J. & Catillaz, J. (2022). Hydrogen for power generation: Experience, requirements, and implications for use in gas turbines [GEA34805]. *General Electric.* https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf
[40] Kizuna. (2022). Hydrogen Power Generation for a Zero-Carbon World. *Government of Japan*. https://www.japan.go.jp/kizuna/2022/08/hydrogen_power_generation.html

of renewable energy — whether wind, solar PV, or a combination — significantly influences the overall emissions profile of green hydrogen. As the IPCC (2014) highlighted, onshore wind technologies have lower CO_2 emissions than offshore wind or solar PV, making them a more favorable option for reducing greenhouse gases. Consequently, this assessment focuses on the life cycle of green hydrogen produced using surplus onshore wind energy for the electrolysis process, aiming to clarify the sustainability of green hydrogen within this context.

The sustainability of green hydrogen hinges on the life cycle assessment (LCA) of its production. An LCA evaluates the environmental impacts at each stage—from raw material extraction, equipment manufacturing, and operational energy use, to decommissioning and recycling. The primary factor in green hydrogen's environmental footprint is the energy source used for electrolysis. Hydrogen is a clean energy carrier, but the sustainability of its production depends on whether the electricity powering electrolysis comes from renewable or non-renewable sources.

Among renewable energy options, onshore wind is one of the most sustainable choices for producing green hydrogen. The IPCC (2014) reports that onshore wind has a significantly lower carbon footprint than offshore wind and solar PV. Life cycle data shows that onshore wind turbines generate roughly 11 grams of CO_2 per kilowatt-hour (kWh) of electricity, compared to solar PV, which can emit up to 48 grams per kWh.[41] The shorter energy payback period of onshore wind turbines—the time required to generate the amount of energy used in their production—enhances their sustainability, making them ideal for green hydrogen production.

The electrolysis process powered by onshore wind energy further reduces greenhouse gas (GHG) emissions compared to other technologies. Most emissions from this process stem from the construction, maintenance, and eventual decommissioning of wind turbines, while the operational phase is virtually emission-free. By utilizing surplus energy from wind farms—energy that would otherwise be wasted—hydrogen production also helps balance the intermittency of wind energy. This symbiotic relationship between wind energy and hydrogen storage enhances the sustainability of both technologies, allowing for more efficient use of renewable resources.

Green hydrogen's lifecycle GHG emissions are significantly lower when wind energy powers electrolysis. Hydrogen produced using onshore wind energy can emit as little as 0.7 to 1.2 kilograms of CO_2 per kilogram of hydrogen. In contrast, "blue hydrogen," produced from natural gas with carbon capture and storage, emits between 3.5 and 4.5 kilograms of CO_2 per kilogram of hydrogen.[42] These figures underscore the substantial environmental benefits of using renewable energy, such as onshore wind, for hydrogen production.

Beyond GHG emissions, several other sustainability metrics must be considered, including water usage, land footprint, and resource consumption. Wind energy typically requires less water than solar PV systems during operation, making it a more sustainable option in water-scarce regions. However, the land footprint of onshore wind farms can be a concern, particularly for large-scale projects. Nonetheless, wind energy is widely regarded as one of the most environmentally benign sources available today.

[41] Bruckner, T., Fulton, L., Hertwich, E., McKinnon, A., Perczyck, D., Roy, J., Schaeffer, R., Schlomer, S., Sims, R., Smith, P., & Wiser, R. (2018). Annex III: Technology-specific Cost and Performance Parameters. *Intergovernmental Panel on Climate Change (IPCC).* https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf

[42] National Renewable Energy Laboratory (NREL). (2004). Life Cycle Assessment of Renewable Hydrogen Production via Wind/Electrolysis. https://www.nrel.gov/docs/fy04osti/35404.pdf.

Green hydrogen production offers significant opportunities for enhancing the sustainability of energy systems when integrated with wind power. Hydrogen can be a storage medium for surplus energy during periods of low demand or high wind output. Instead of being curtailed, this excess energy is diverted to produce hydrogen, which can be stored or transported for use in industries, transportation, or power generation later. This integration also boosts the efficiency of wind energy by minimizing energy waste and ensuring a consistent renewable energy supply across various sectors.

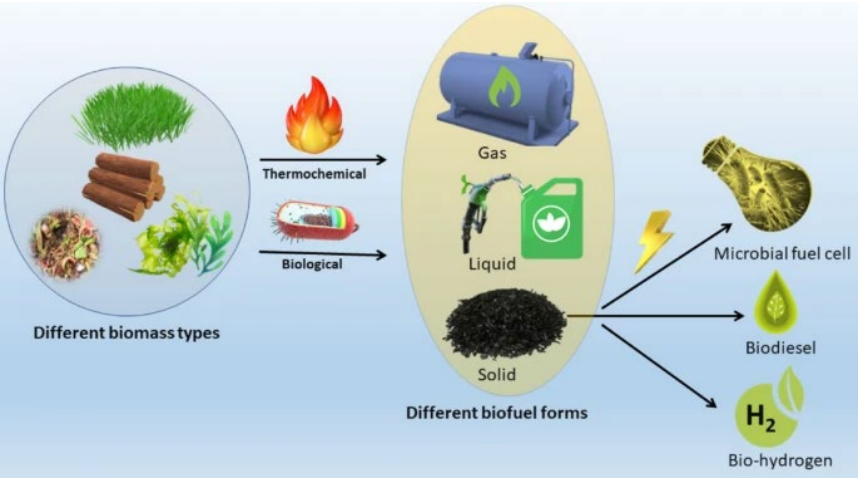
In conclusion, the sustainability of green hydrogen production is fundamentally tied to the renewable energy sources powering the electrolysis process. Onshore wind, with its low life cycle emissions and minimal resource use, provides one of the most sustainable pathways for producing green hydrogen. As demand for hydrogen increases across industries, ensuring that renewable energy sources like wind are utilized is critical to maximizing the environmental benefits of this emerging technology. By harnessing wind energy for electrolysis, green hydrogen can play a pivotal role in decarbonizing sectors that are difficult to electrify, making it an essential component of a sustainable energy future.

17.0 *New Resource Option: Biofuels*

17.1 Description

Biofuels are fuels that are made from biomass materials, which are plant-based materials such as wood, energy crops, agricultural residues, and waste from industry, farms, and households, which are refined and converted to a high-energy-density product in either a solid, liquid, or gaseous state. To be converted to electricity, this product is typically burned directly, like traditional fossil fuels, in either a diesel, gas turbine, or boiler and steam turbine generator. However, the major benefit of biofuels is that they have a carbon-neutral impact since the carbon released during their combustion is equal to the carbon sequestered by the source agriculture product during its growth cycle. Biofuels are not a new technology; humans have relied on solid biomass, such as wood, for heat and cooking since prehistoric times. Modern technology has allowed for the evolution of biofuels, and access to different biofuels is now available depending on the state of matter as well as the feedstock type (Figure 26).

Figure 26: Diagram of Basic Biofuel Components and Products[43]

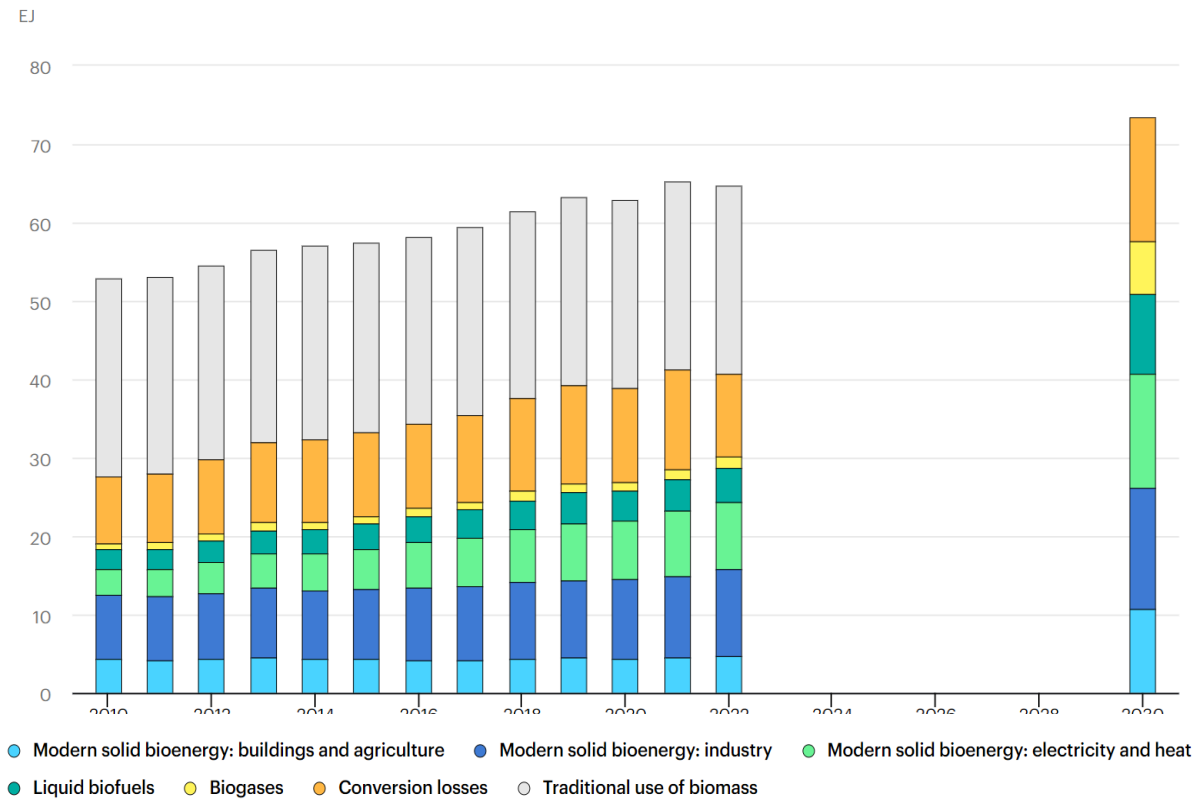


Globally, biofuel production and usage have increased and have been used across industries to replace fossil fuels. According to the International Energy Agency, bioenergy accounts for 55% of all renewable energy and 6% of global energy supply, with global usage increasing by an average of 3% per year since 2010.[44] Biofuels are not only used for energy generation but also as a replacement/substitute for fossil fuels for transportation, process steam production, cooking, and building heating. Of the various types of biofuels, the most common and globally emphasized include ethanol, biodiesel, renewable diesel, bio-aviation fuel, and biogas, in addition to traditional solid biofuels (Figure 27).

[43] Osman, A., Lai, Z.Y., Farghali, M., Yiin, C.L., Elgarahy, A.M., Hammad, A., Ihara, I., Al-Fatesh, A.S., Rooney, D.W., Yap, P.S. (2023). Optimizing Biomass Pathways to Bioenergy and Biochar Application in Electricity Generation, Biodiesel Production, and Biohydrogen Production. *Environmental Chemistry Letters*, vol. 21, no. 5, June 2023, pp. 2639–705. https://doi.org/10.1007/s10311-023-01613-2

[44] International Energy Agency (IEA). (2023). Bioenergy. https://www.iea.org/energy-system/renewables/Bioenergy

Figure 27: Global Bioenergy Use by Sector, Including Projections for 2030 in the Net Zero Scenario[45]



Given its widespread application in electric generation capacities, this report will focus on biodiesel, with auxiliary information on bioenergy sources such as recycled grease, biogas, and ethanol. Biodiesel is made from vegetable oils and animal fats through transesterification, where the feedstock reacts with alcohol and a catalyst. Approximately 90% of biodiesel in the United States is made from soybean oil.[46] It can be substituted for petroleum-based diesel fuel in any application with minimal modifications, though it is primarily used in some fuel mix with traditional diesel fuel. B20 is a blended fuel mix of 20% biodiesel and 80% petroleum diesel (traditional fossil-based diesel), which limits the impact on the turbine to a minimum. Biodiesel generally has a slightly lower energy content than petroleum diesel (120,000 BTU per gallon vs 137,000 to 136,000 BTU per gallon, respectively). The United States has produced biofuels steadily in recent years, with an average of 2.2 billion gallons of biodiesel capacity monthly since 2021, in addition to 17.6 billion gallons and 2.5 billion gallons monthly of bioethanol and other biofuels, respectively, according to the International Energy Agency (IEA).[47] Similar to biodiesel, renewable diesel is created from virtually any feedstock. However, it uses a hydrogenation process that

[45] International Energy Agency (IEA). (2024). Bioenergy use by sector globally in the net zero scenario, 2010–2030 – Charts – Data & Statistics. https://www.iea.org/data-and-statistics/charts/Bioenergy-use-by-sector-globally-in-the-net-zero-scenario-2010-2030

[46] Pennsylvania State Extension (Penn State Extension). (2023). Biodiesel: A renewable, domestic energy resource. https://extension.psu.edu/Biodiesel-a-renewable-domestic-energy-resource

[47] U.S. Energy Information Administration (EIA). (2024). U.S. total Biofuels operable production capacity. https://www.eia.gov/dnav/pet/pet_pnp_capBio_dcu_nus_m.htm

is chemically identical to petroleum diesel. Therefore, there is no need for fuel mixing or mechanical system alterations.[48]

From a policy perspective, biofuels have a strong legislative backing as they have been incentivized in acts such as the Inflation Reduction Act, which provides over $500 million for grants related to increasing biofuel (namely biodiesel and bioethanol) production and distribution, in addition to the extension of a Biofuel and Renewable Diesel Credit.[49] The Environmental Protection Agency (EPA) also lists biofuels as a focus of the Renewable Portfolio Standards program. Many reports have been conducted on the feasibility of further biofuel integration in the US transportation and electric generation fuel systems, such as the EPA's triennial Report to Congress on Biofuels and the Environment. This study details current trends in domestic biofuel production and other primary biofuel sources, such as ethanol imports from Brazil.[50] In Puerto Rico, the Renewable Portfolio Standard recognizes biofuels as renewable fuels and classifies combustion from biofuels as sustainable renewable energy.[51] Likewise, multiple reports, including the Department of Energy's (DOE) PR100, have identified biofuels numerous times as a key contributor to Puerto Rico's energy future.[52]

17.2 Technology Maturity

Biofuels have become an increasingly important alternative to fossil fuels as the world shifts towards more sustainable and renewable energy sources. Because of this, they are in a mature deployment stage. These fuels, derived from organic materials, can reduce greenhouse gas (GHG) emissions and decrease reliance on traditional carbon-emitting fossil fuels like coal, oil, and natural gas. As technology has progressed, biofuels have evolved into different categories called generations. The type of feedstock used determines the first three generations of biofuels, while genetic engineering produces the fuels in the fourth generation.

This evolution reflects ongoing efforts to make biofuels more sustainable, cost-effective, and scalable globally. Biofuels' categorization into generations demonstrates their technological maturity. First-generation biofuels are well-established and widely used, while fourth-generation biofuels remain in development. Thus, fourth-generation biofuels represent the future of advanced biofuel technology.

The first generation of biofuels is based on the chemical conversion of oils (animal and vegetable) to produce biodiesel and the fermentation of starch to produce bioethanol and biobutanol. These biofuels have been developed to a mature stage and are commercially viable and widely adopted. The feedstocks typically used to produce these biofuels are crops used for food and feed production, which may lead to land use change, deforestation, food insecurity, and habitat loss issues.[53, 54]

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[48] U.S. Energy Information Administration (EIA). (2022). Biofuels explained: Biodiesel, renewable diesel, and other Biofuels. https://www.eia.gov/energyexplained/Biofuels/Biodiesel-rd-other-basics.php

[49] Bipartisan Policy Center (BPC). (2022). Inflation Reduction Act summary: Energy and climate provisions. https://bipartisanpolicy.org/blog/inflation-reduction-act-summary-energy-climate-provisions/

[50] U.S. Environmental Protection Agency (EPA). (2021). Biofuels and the Environment: Third triennial report to Congress (External Review Draft). https://assessments.epa.gov/Biofuels/document/&deid=353055

[51] "Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act" Act No. 82 of July 19, 2010, Page 7.

[52] National Renewable Energy Laboratory (NREL). (2024). Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100). https://docs.nrel.gov/docs/fy24osti/88615.pdf

[53] Renzaho, A.M.N., Kamara, J.K., & Toole, M. (2017). Biofuel Production and Its Impact on Food Security in Low- and Middle-Income Countries: Implications for the Post-2015 Sustainable Development Goals. *Renewable and Sustainable Energy Reviews*, Vol. 78 (October 2017): 503–16. https://doi.org/10.1016/j.rser.2017.04.072

[54] Sun, Y. (2024). Technology Research and Development Prospects of Biofuels. *Journal of Education and Educational Research*, Vol. 7 (1): 11–15. https://doi.org/10.54097/ks2m1h72

Second-generation biofuels are derived from non-food sources, such as agricultural by-products (e.g., cereal straw, sugarcane bagasse), waste materials (e.g., forest residues, organic components from municipal solid waste), and dedicated feedstocks (e.g., energy crops, short-rotation forests). This approach addresses the ethical and environmental concerns associated with using food crops for fuel production:

- Thermo-chemical reactions, such as pyrolysis or gasification, produce syngas (CO+H2). After cleaning and synthesizing the gas, the resulting product can be refined into hydrocarbon fuels.
- Biochemical reactions consist of the enzymatic transformation of lignocellulosic biomass into sugars, which are then fermented to produce bioethanol.[55, 56]

While second-generation biofuels offer a more sustainable alternative, they are significantly more complex to produce than first-generation biofuels. This complexity increases production costs, making them less widely adopted despite technological advances. Consequently, despite being mature, their market penetration remains limited due to challenges related to cost and competitiveness.

Third-generation biofuels are typically derived from algal biomass due to the high lipid content and the high productivity of these microorganisms, with the potential of producing one to seven g/L/day of biomass in small land units. As such, they are very efficient biofuel feedstock from non-food sources, reducing the potential negative impacts of first- and second-generation biofuels. However, the production of third-generation biofuels implies large volumes of water and a subsequent dewatering process to extract the lipids needed for producing a series of fuels that include biodiesel, bioethanol, and biogas by a transesterification process and jet fuel by a hydrogenolysis process. Researchers must conduct more studies to improve the production, distribution, and economic viability of these biofuels, enabling their widespread use.[57]

Fourth-generation biofuels involve genetic engineering of microorganisms, such as microalgae, yeast, fungi, and cyanobacteria, to increase the desired traits of organisms used in biofuel production. This goes from using multiple types of sugars to higher lipid synthesis or increased photosynthesis and carbon fixation. This biofuel generation has an increased quantity and quality of the fuels provided. Moreover, the fuels obtained through this method have the potential to be carbon negative. However, this type of biofuel is still in the conceptual stage at the laboratory scale. In addition, political and public support should be increased to promote the development of this type of biofuel.[58]

17.3 Cost

The United States largely dominates biofuel production and export, producing over 57.5 billion liters of bioethanol and 14.5 billion liters of biodiesel in 2022, as shown in Figure 28.[59] Brazil and Indonesia also produce significant amounts of biofuels, and along with India, are substantial drivers of increased global

[55] Pattanaik, B.P. & Misra, R.D. (2017). Effect of Reaction Pathway and Operating Parameters on the Deoxygenation of Vegetable Oils to Produce Diesel Range Hydrocarbon Fuels: A Review. *Renewable and Sustainable Energy Reviews*, Vol 73 (June 2017): 545–57. https://doi.org/10.1016/j.rser.2017.01.018

[56] Shadangi, K.P., Sarangi, P.K., Mohanty, K., Deniz, I. & Ravi, A. (2023). *Bioenergy Engineering*. Elsevier.

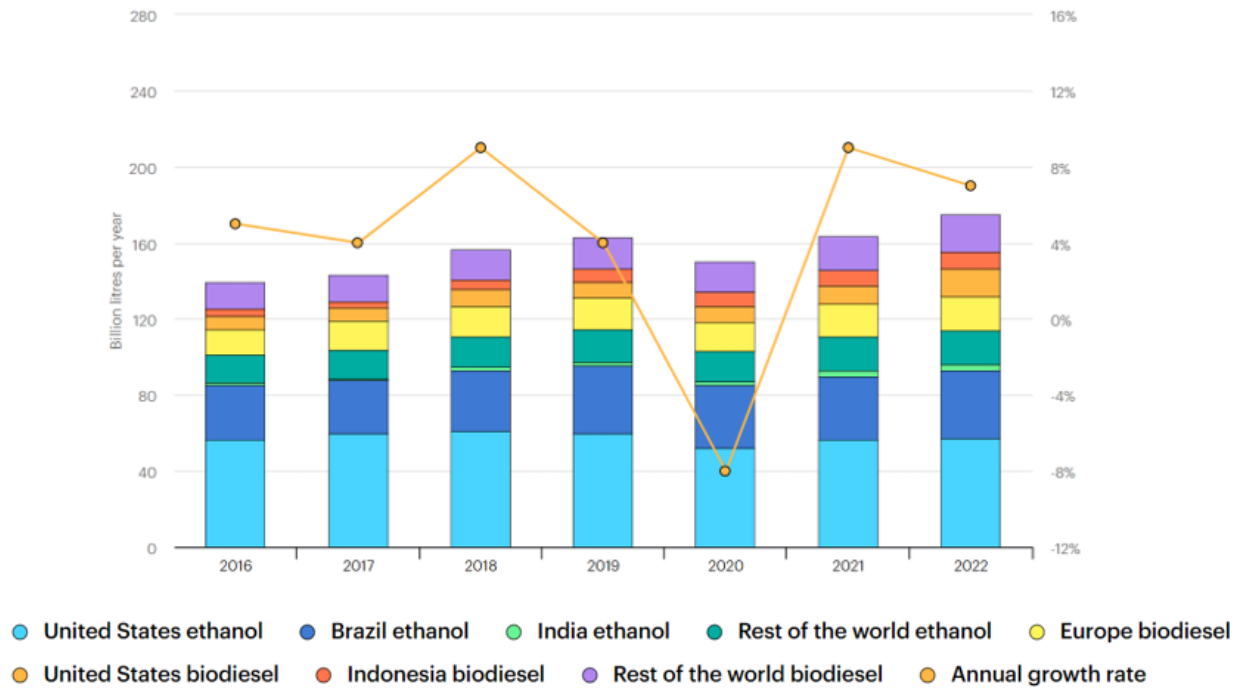
[57] Lee & Lavoie. (2013). From first- to third-generation Biofuels: Challenges of producing a commodity from a Biomass of increasing complexity. *Animal Frontiers*, 3(2), 6–11. doi.org/10.2527/af.2013-0010

[58] Cavelius, P., Engelhart-Straub, S., Mehlmer, N., Lercher, J., Awad, D. & Brück, T. (2023). The Potential of Biofuels from First to Fourth Generation. *PLOS Biology*, 21 (3): e3002063. https://doi.org/10.1371/journal.pBio.3002063

[59] International Energy Agency (IEA). (n.d.). Biofuel production by country/region and fuel type, 2016–2022. https://www.iea.org/data-and-statistics/charts/Biofuel-production-by-country-region-and-fuel-type-2016-2022.

demand for biofuels due to their robust biofuel policies, rising transportation fuel demand, and abundant feedstock potential.[60] As shown in Figure 28, retail prices of several biofuels in the US have been subject to variation due to global market trends, but B20 has historically remained within a range of $0.15 per diesel gallon equivalent from diesel. In contrast, B99/B100 and renewable diesel are much higher-cost alternatives, along with propane.

Figure 28: Global Leaders in the Production of Biodiesel and Bioethanol



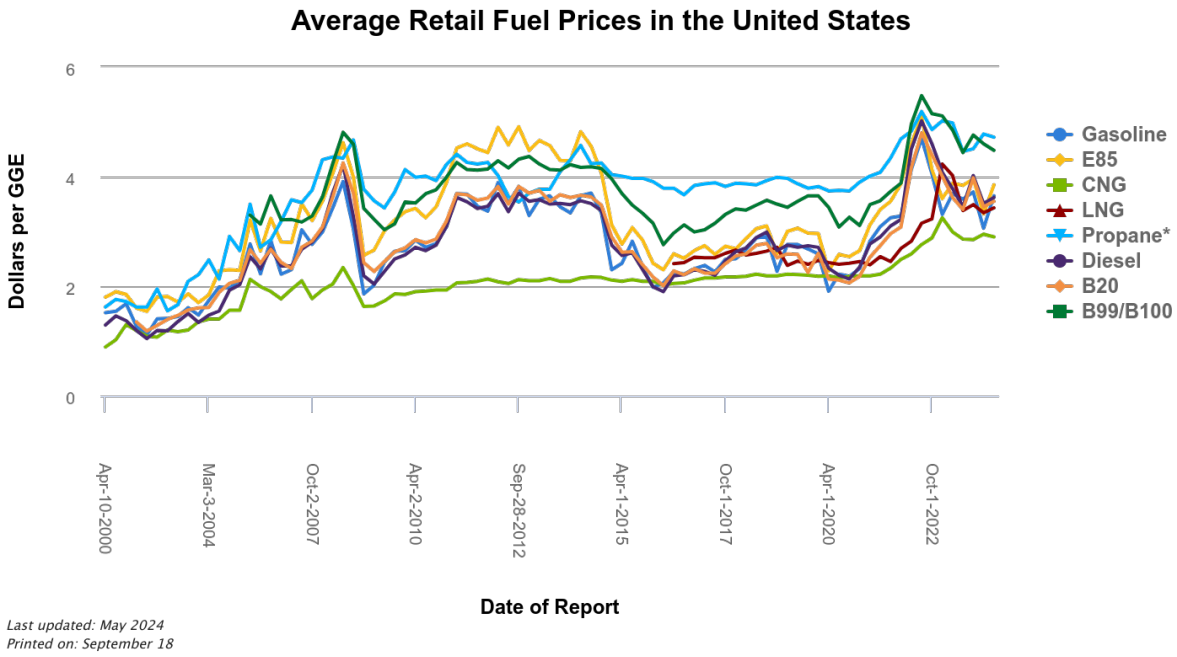
Looking to the future, the International Energy Agency is projecting a significant increase in biofuel demand and production, with demand projected to increase globally by 38 billion liters over 2023-2028 and emerging economies set to drive 70% of global demand growth over the forecasted period.[61] This increased demand for biofuels primarily correlates with their use in the transportation sector, as bioenergy capacity forecasts for electric generation are set to stagnate in many emerging economies. This is due to various factors, including emphasizing other renewable generation technologies, logistical complications, and more valuable utilization in the transportation sector. Regardless, the United States and other countries globally are deploying various tools to bridge the cost gaps between biofuels and traditional fossil fuels, such as the U.S. extending the biodiesel blending tax credit of $1.00 per gallon and adding GHG emission incentives through the Inflation Reduction Act. [62]

[60] International Energy Agency (IEA). (2023). Transport Biofuels – Renewables 2023 – Analysis. https://www.iea.org/reports/renewables-2023/transport-Biofuels

[61] International Energy Agency Bioenergy (IEA Bioenergy). (2024). IEA Renewables 2023 – Biofuel and Biogas forecasts. https://www.ieaBioenergy.com/blog/publications/iea-renewables-2023-Biofuel-and-Biogas-forecasts/

[62] U.S. Energy Information Administration (EIA). (n.d.). U.S. Biomass-based diesel tax credit renewed through 2022 in government spending bill. https://www.eia.gov/todayinenergy/detail.php?id=42616

Figure 29: Average Retail Fuel Prices of Biofuels in the U.S.[63]



Biodiesel can be utilized in various types of generation units, including peakers and baseload units, each operating at different capacity factors. In Puerto Rico, the levelized cost of energy (LCOE) for biodiesel varies significantly, ranging from $0.27 per kWh to $2.04 per kWh. These costs are generally higher in island environments like Puerto Rico due to several factors such as elevated fuel and equipment transportation expenses, limited economies of scale, land constraints, and the necessity for additional investments in grid stability, such as energy storage and backup generation systems.

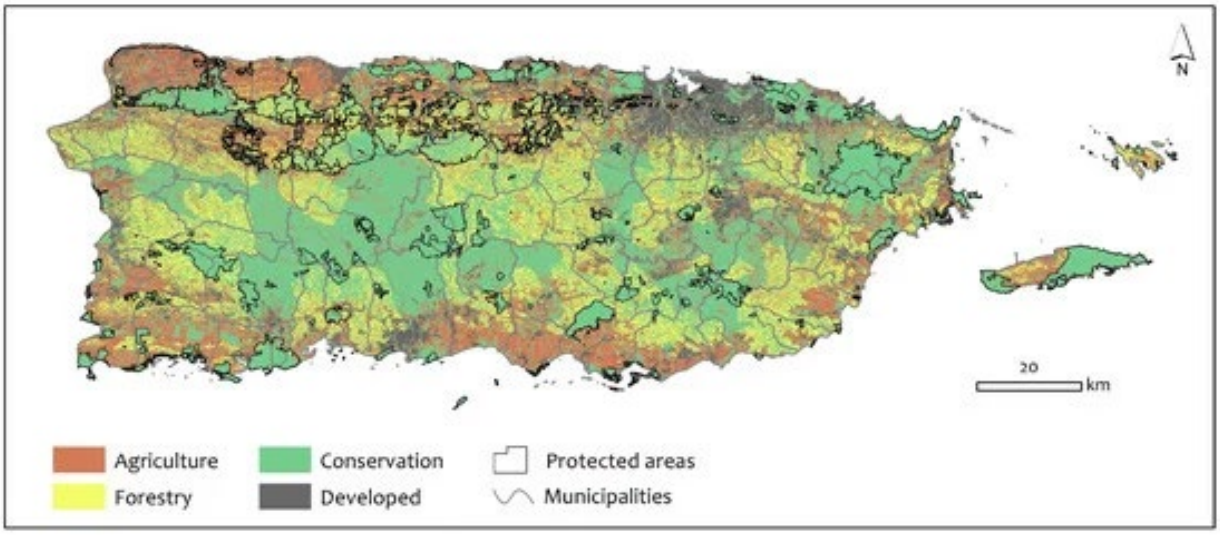
17.4 Supply Chain

The biofuel supply chain includes the production of biomass feedstocks, including harvesting, collecting, and storage. This is followed by transportation to a biorefinery, where biomass is converted to biofuels, which are distributed to end users for consumption.[64]

Agricultural land in Puerto Rico is a scarce resource, comprising only about 22-23% of the Island's total land area (Figure 30), a smaller proportion than most countries with greater land area in the Caribbean and Central America. In addition, Puerto Rico imports over 80% of its food supply, further constraining the potential for biofuel production from agricultural sources.[65]

[63] U.S. Department of Energy. (n.d.). Alternative Fuels Data Center: Maps and Data. https://afdc.energy.gov/data
[64] National Academies Press. (2011). Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy. *National Academies*, P. 29. https://nap.nationalacademies.org/read/13105/chapter/4
[65] Sotomayor-Ramírez, D. (2021). The Case for Preserving Agricultural Land Area in Puerto Rico and Green-Energy Projects. *U.S. House of Representatives*. https://docs.house.gov/meetings/II/II00/20211006/114107/HHRG-117-II00-20211006-SD010.pdf

Figure 30: Map Showing that Approximately 23% of Puerto Rico's Total Land Area is Designated for Agriculture[66]



As a result, biofuels derived from local agriculture are a less viable option for the Island's energy generation. A more viable alternative feedstock is organic waste, including agricultural residues, food waste, and potentially municipal solid waste, which can be processed into biofuels. However, to fully realize its potential, significant improvements are needed in Puerto Rico's waste management system, as currently, over 86% of the Island's waste ends up in landfills. [67, 68] Due to the limited local production of feedstocks, most of them should be imported to generate biofuels at a large scale.

Biofuel production in Puerto Rico is minimal. No commercial-scale operations are in place, so production is limited to pilot or research initiatives.[69] One example of these projects is the design and development of an offshore cultivation system for tropical seaweeds, which aims to produce biofuels from algae on a large scale. This study, sponsored by the Marine Biological Laboratory of the University of Chicago, explores cultivation methods for algae species in offshore environments while conducting economic feasibility assessments. However, this project remains in the research phase with no commercial-scale implementation.[70, 71]

To successfully implement biofuel production in Puerto Rico, further investments in infrastructure, policy support, and technology scaling will be necessary. With the current situation, biofuels must be imported to the Island to play a more significant role in Puerto Rico's energy mix. While traditional biodiesel from agricultural products may have its limitations in Puerto Rico, another source of biodiesel that may have a future in Puerto Rico would be recycled agriculture-based oils. In a similar refining process but on a

[66] Gould, W.A., Wadsworth, F.H., Quiñones, M., Fain, S.J. & Álvarez-Berríos, N.L. (2017). Land use, conservation, forestry, and agriculture in Puerto Rico. *Forests*, 8(7), 242. https://doi.org/10.3390/f8070242
[67] U.S. Environmental Protection Agency (EPA). (n.d.). Review of Municipalities Mitigating for Future Disasters Today. https://www.epa.gov/system/files/documents/2021-09/gfx-solid-waste-management-in-puerto-rico.pdf
[68] Cruz Mejías, C. (2021). Trash Crisis Leaves Puerto Rico Near 'the Brink'. *Global Press Journal*. https://globalpressjournal.com/americas/puerto-rico/trash-crisis-leaves-puerto-rico-brink/
[69] Petrovic, S. & Buchanan, K. (2023). Puerto Rico. In World Energy Handbook (pp. 299–302). *Springer Nature Link*. https://doi.org/10.1007/978-3-031-31625-8_32
[70] Marine Biological Laboratory (MBL). (n.d.). *Tropical Seaweed Farm Project.* https://www.mbl.edu/research/research-centers/eugene-bell-center/featured-projects/tropical-seaweed-farm-project
[71] Algae Planet. (2021). *Puerto Rico Testing Seaweed Farm for Biofuels. Algae Planet.* May 17, 2021. https://algaeplanet.com/puerto-rico-testing-seaweed-farm-for-Biofuels/

smaller scale, biofuel can be created from waste cooking oil to be repurposed for transportation uses. This takes advantage of existing waste and thus bypasses agricultural land use concerns and provides potential GHG emission reductions in the transportation sector. There are several different methodologies employed for the treatment of waste cooking oil and subsequent conversion into biodiesel, as summarized in Figure 31, based on a 2022 study.[72] BIO OIL Group, based in Austria, is one of many companies globally that has a BIOWCO collection service and several treatment and processing facilities across Europe to create biodiesel.[73]

Figure 31: Comparisons of Waste Cooking Oil Treatment and Processing Methods[72]

Process	Main Process	Advantages	Disadvantages
Pyrolysis	The oil is preheated and decompose at certain temperature (generally high) with or without catalyst. The analysis is based on their boiling temperature of different products, such as gas and liquids	The process is effective, simple, and free pollution and waste	It is necessary to use expensive and high-temperature equipment. Produce biodiesel with a low purity level
Transesterification	The oils are reacting with present of alcohol as solvent and catalyst. The biodiesel obtain with glycerol will be separate and purify before further usage	High conversion with low cost, mild reaction conditions, the biodiesel obtain closer to the petroleum diesel and applicable for industrial production	Require low amount of free fatty acid and water content in the raw materials, extensive separation and purification steps and generate large amount of wastewater
Micro emulsification	The oils were solubilized in a solvent and surfactant until the require viscosity is obtained	Easy process and pollution free	High viscosity, low stability and could lead to sticking, incomplete combustion and carbon deposition

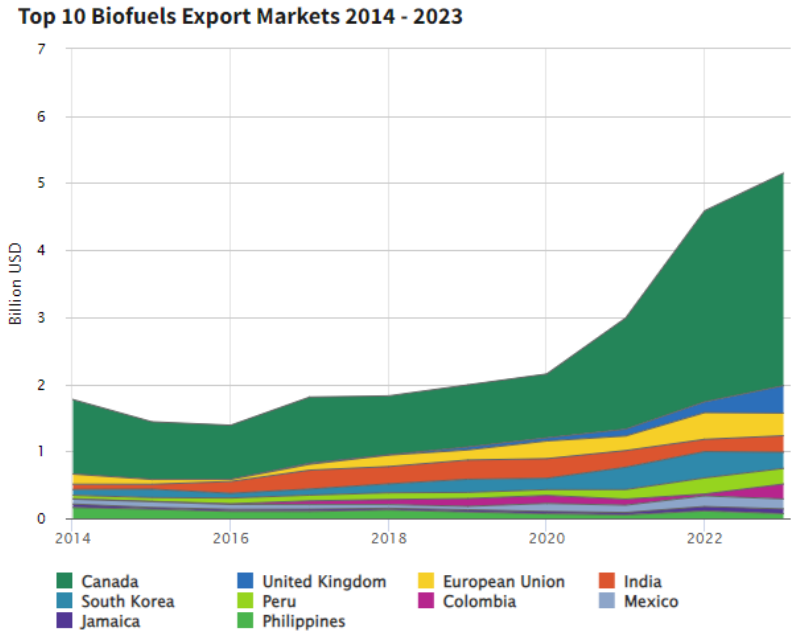
Although feedstock generation and biofuel production are not yet commercially developed in Puerto Rico, biofuels have significant potential for local consumption, particularly in two key markets: transportation and power generation. In the transportation sector, biofuels could be introduced as fuel blends, such as E10 (10% ethanol and 90% gasoline) or B20 (20% biodiesel and 80% diesel). While still an emerging technology, bio-aviation fuels also hold the potential to impact aviation fuel consumption in Puerto Rico substantially. Furthermore, biofuels could play a critical role in energy generation, enabling Puerto Rico to diversify its energy resources, reduce its reliance on fossil fuels—currently responsible for over 90% of energy production—and lower the carbon footprint associated with energy generation.[74]

Given the potential for biofuel use in Puerto Rico's energy market and the Island's limited capacity for local production, the most viable short- to mid-term solution is to import biofuels. With the United States' well-established biofuel production and supply chain infrastructure, it is a major global supplier, exporting to Canada, the European Union, Latin America, and Asia, as shown in Figure 32 below. This positions the United States as a key biofuel supplier for Puerto Rico. Leveraging this existing supply chain would

[72] Suzihaque, M.U.H., Alwi, H., Ibrahim, U.K., Abdullah, S. & Haron, N. (2022). Biodiesel Production from Waste Cooking Oil: A Brief Review. *Materials Today: Proceedings*, 63 (1). https://doi.org/10.1016/j.matpr.2022.04.527
[73] Bio-Oil.biz. (2024). *Bio Oil*. https://Bio-oil.biz/#produktion-en
[74] U.S. Energy Information Administration (EIA). (2022). Biofuels explained. https://www.eia.gov/energyexplained/Biofuels/.

allow Puerto Rico to incorporate biofuels into its energy mix while exploring longer-term solutions, such as expanding local production capacity or developing alternative feedstocks.[75]

Figure 32: Growth of U.S. Biofuels Exports from 2014 to 2023[75]



17.5 Construction and Development

Since traditional biofuel production in Puerto Rico is currently limited due to low agricultural and waste oil feedstock availability, the focus has shifted to potential modifications for existing diesel generators and power plants. As previously mentioned, B20 fuel mix can be used with minimal, if any, modifications to the equipment, although maintenance requirements may change (see Operations section). There have been residential and industrial-scale B100 generators,[76] as well as pilot projects exploring using B100 in transportation, such as marine fleets, with no engine modification required.[77] However, the use of biofuels for utility-scale electricity generation has been limited to solid biofuels. For example, in the UK, the Drax power plant generates 14 TWh of electricity using wood pellets in four 645 MW units.[78] There is minimal documented use of liquid biofuels, such as biodiesel, in utility-scale electricity generation, which would likely occur in a retrofitted combined cycle or diesel/gas turbine.

17.6 Operation

Considering the flexibility of dispatching biofuel generation, studies such as PR100 have highlighted the need for biodiesel generation to achieve 100% renewable sources penetration in Puerto Rico's energy mix. Significant mature and emerging technology installations will be required to reach this goal. In the

[75] U.S. Department of Agriculture, Foreign Agricultural Service (USDA FAS). (n.d.). Biofuels. https://fas.usda.gov/data/commodities/Biofuels.
[76] JS Power. (n.d.). *Bio-Diesel Generators | Eco Friendly Generator | Bespoke Generators.* JS Power Limited. https://jspower.co.uk/Bio-diesel-generators/
[77] CSL. (2021). CSL Successfully Completes World's Largest B100 Biofuel Tests. https://cslships.com/news/csl-successfully-completes-worlds-largest-b100-Biofuel-tests/
[78] Drax Global. (n.d). Drax Power Station. www.drax.com/about-us/our-sites-and-businesses/drax-power-station

long term, deploying utility-scale and distributed PV, wind generation, storage technologies, and dispatchable renewable resources will be essential. PR100 identified the need for over 1,300 MW of biodiesel generation (or other equivalent “firm” generation), a dispatchable asset that provides flexibility for a highly renewable energy system. [79]

While biofuels offer an alternative to traditional fossil fuels, they come with distinct operational, maintenance, reliability, resilience, and logistical considerations compared to other fuel-based technologies. These factors emphasize the importance of understanding how biofuels integrate with existing technologies and systems.

Regarding operation, biofuels can be used in existing combustion engines or energy generation systems. For instance, biodiesel can be blended with regular diesel (B20) and used in standard diesel engines. Furthermore, with minimal modifications to the existing equipment, such as replacing fuel injectors or seals, engines may be able to operate on a 100% biofuel blend. However, it should be considered that the energy density of biofuels is typically lower than fossil fuels, meaning that more fuel will be needed to achieve the same power output.

Biofuels generally require more frequent and specialized maintenance than fossil fuels due to their unique chemical properties, which can impact engine components. For biodiesel, one common issue is the formation of deposits in the engine, leading to clogging, though this is typically associated with poor-quality biodiesel. When using high-quality biodiesel, these issues are largely mitigated. Another challenge with biodiesel is its tendency to gel in cold weather, however, special biodiesel blends have been developed to enhance performance in lower temperatures, minimizing temperature-related complications.[80] Biogas, primarily composed of CH4 (35–75%) and CO_2 (25–60%), also contains impurities that should be removed, increasing the maintenance needs compared to natural gas.[81] Lastly, ethanol blends, particularly those with higher percentages, may absorb moisture, causing engine issues due to corrosion.[82]

Regarding resilience, biofuels provide the potential for decentralized, locally based production, reducing reliance on imported fossil fuels. This localized approach enhances energy security by making regions less dependent on the volatile global oil market. By producing biofuels domestically, countries or regions can shield themselves from the global supply chain disruptions and fluctuations in fuel prices. This energy resilience is particularly important during geopolitical instability or supply shortages. While fossil fuels depend on complex, international supply chains, biofuels can be sourced from local feedstocks, offering a more stable and sustainable energy solution for regions with the capacity to produce them. This increased energy independence not only improves resilience but also fosters long-term energy sustainability.[83]

[79] U.S. Department of Energy (DOE). (2024). Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100). https://www.energy.gov/gdo/puerto-rico-grid-resilience-and-transitions-100-renewable-energy-study-pr100

[80] Ciolkosz, D. (2016). Using Biodiesel Fuel in Your Engine. *Penn State Extension*, June 9, 2016. https://extension.psu.edu/using-Biodiesel-fuel-in-your-engine

[81] Bragança, I., Sánchez-Soberón, F., Pantuzza, G.F., Alves, A. & Ratola, N. (2020). Impurities in Biogas: Analytical Strategies, Occurrence, Effects and Removal Technologies. *Biomass and Bioenergy*, Volume 143 (December): 105878. https://doi.org/10.1016/j.BiomBioe.2020.105878

[82] Baena, L.M., Vásquez, F.A., Calderón, J.A. (2021). Corrosion Assessment of Metals in Bioethanol-Gasoline Blends Using Electrochemical Impedance Spectroscopy. *Heliyon*, Volume 7 (7): e07585. https://doi.org/10.1016/j.heliyon.2021.e07585

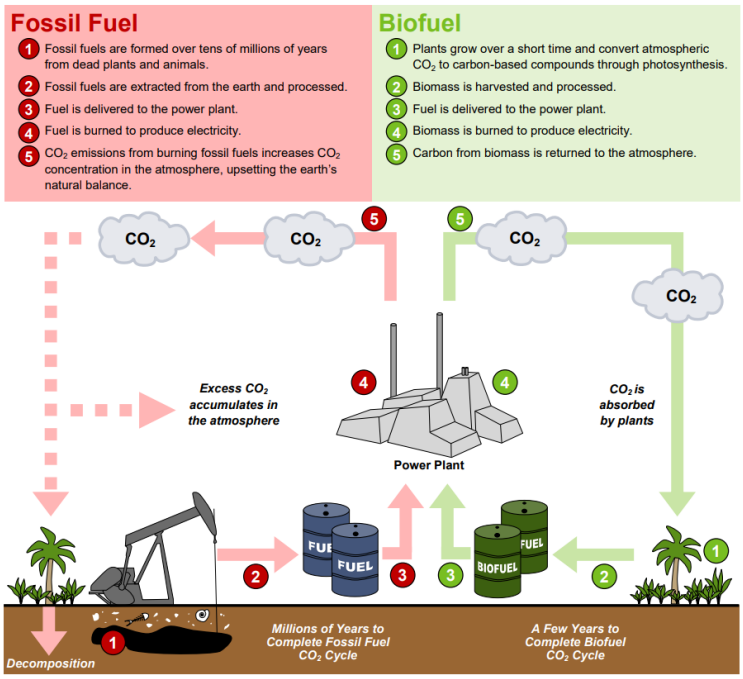
[83] U.S. Environmental Protection Agency (EPA). (2019). Economics of Biofuels. https://www.epa.gov/environmental-economics/economics-Biofuels

To conclude, biofuels offer a promising alternative for enhancing Puerto Rico's sustainability and energy independence. However, further development in maintenance and reliability is needed to match the established advantages of fossil fuels.

17.7 Sustainability

One of the most cited benefits of using biofuels to supplement fossil fuel consumption is their potential to reduce greenhouse gas (GHG) emissions across their entire life cycle (Figure 33). Although biofuels are still burned in the same way as traditional fossil fuels and thus produce GHG emissions, they are produced from biomass that sequesters carbon during their growth. As a result, biofuels are generally considered to have a zero net impact or a zero net increase in atmospheric carbon during combustion. While fossil fuels take millions of years to form and, if left untouched, will not release their stored carbon into the atmosphere, the feedstock for biofuels grows over months to years, capturing carbon through photosynthesis. Therefore, the carbon released during the combustion of biofuels is equivalent to what was stored during the plant's growth. This release of only sequestered carbon during combustion is why biofuels are called carbon-neutral fuels. Private researchers and government agencies alike have studied this phenomenon extensively, focusing on different feedstocks and their lifecycle emissions, as shown in the EPA's research in Figure 33.[84] While different feedstocks have different carbon sequestration and fuel conversion rates, practically all biofuels result in lower lifecycle GHG emissions than traditional gasoline or diesel.

Figure 33: Diagram of Biofuel and Fossil Fuel Lifecycles[84]

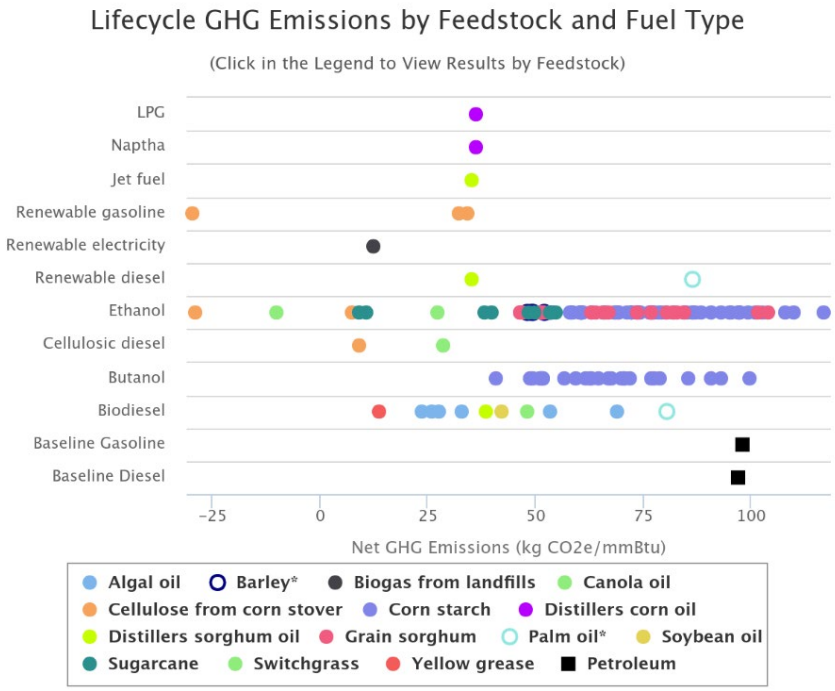


In addition to GHG emissions, biofuel production has several other environmental impacts that are consistent with the agricultural industry. The agricultural basis of biofuel production can result in

[84] U.S. Environmental Protection Agency (EPA). (2016). Lifecycle greenhouse gas results. https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

substantial land use impacts, potentially leading to soil degradation and acidification, as well as water consumption and pesticide/fertilizer runoff, depending on the agricultural practices being employed. Water consumption for soybean-based biodiesel production has been estimated to be 61.78, 0.17, and 0.31 gallons of water per gallon of soybeans at the soybean growth, processing, and biodiesel manufacturing stages, respectively.[85] Even ignoring the crop growth process, fermentation of corn grain consumes 2 to 4 gallons of water per gallon of ethanol produced, while producing a gallon of biodiesel consumes about one gallon of water.[86] With increased production of biofuels and thus increased biofuel feedstock production, more water consumption and pollution can be expected. Furthermore, during the refinement process, a considerable amount of greywater is produced, which is the wastewater produced after meeting legal requirements for diluting chemicals used in the refinement process. These agriculturally focused environmental concerns are something to consider as the production of biofuels increases globally.

Figure 34: Lifecycle Net Greenhouse Gas Emissions for Different Feedstocks, Categorized by Fuel Product[84]



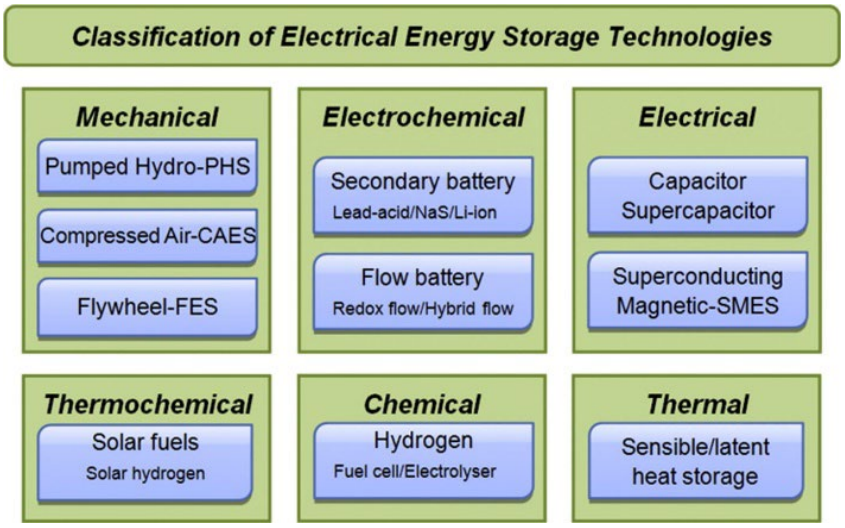
[85] Arshad, M. & Abbas, M. (2017). Water sustainability issues in Biofuel production. In *Springer Nature Link*, Advances in Biorefineries: Products and processes (pp. 55–76). https://link.springer.com/chapter/10.1007/978-3-319-66408-8_3

[86] Cruse, R. & Friedman, D. (2019). Water Use and Sustainable Biofuel Production. *Farm Energy*. https://farm-energy.extension.org/water-use-and-sustainable-Biofuel-production/#:~:text=Water%20use%20for%20Biofuel%20production%20can%20be%20divided

18.0 *New Resource Option: Overview of Non-Battery Energy Storage Systems (ESS)*

Energy storage refers to any technological system that can store and dispatch electricity by utilizing various materials' mechanical, electrochemical, or electromagnetic properties. While much focus has been given to the development and deployment of battery energy storage systems (BESS), a primary issue is the increasing demand and corresponding scarcity of key materials required,[87] in addition to the demand for longer-duration energy storage technologies compared to the industry standard 4-hour cycles. The expectation is that energy storage projects will continue to play an integral role in Puerto Rico's energy future, which will require technological diversification to meet the variable needs and demands of the grid. Outside of BESS, there are a variety of other technologies that present unique opportunities for energy storage within an electric transmission and distribution system. Broadly, energy storage systems (ESS) can be separated into several distinct categories based on the technology being applied and the form of energy stored (Figure 35).

Figure 35: Categorization of Energy Storage Technologies[88]



The main ESS categories are shown below in Figure 35:

- **Mechanical Storage:** Mechanical storage applies force to some mechanical medium to create potential energy and reverses the process to convert it to kinetic energy. Examples include pumped hydro storage, flywheel energy storage, compressed air energy storage (CAES), and gravity energy storage. This report will provide an in-depth analysis of several of these examples.

[87] International Energy Agency (IEA). (2023). Trends in batteries – Global EV Outlook 2023 – Analysis. https://www.iea.org/reports/global-ev-outlook-2023/trends-in-batteries

[88] Luo, X., Wang, J., Donner, M. & Clarke, J. (2015). Overview of current development in electrical energy storage technologies and the application potential in power system operation. *Applied Energy*, 137(1) (January), 511-536. https://doi.org/10.1016/j.apenergy.2014.09.081

- **Electromagnetic Storage:** Electromagnetic storage utilizes magnetic force to store and generate energy, including supercapacitors and superconducting magnetic energy storage.
- **Electrochemical Storage:** Electrochemical storage is the technical term for BESS and includes a variety of battery technologies that are discussed in another section of the IRP Appendix E, "Non-Lithium Battery Storage."
- **Thermal Energy Storage:** Thermal energy storage captures heat either by increasing a medium's temperature (sensible thermal energy storage) or by changing the medium's state of matter without altering its temperature (latent thermal energy storage).

While these technologies currently span a range of technical and commercial maturity, they can significantly contribute to transforming and improving Puerto Rico's energy grid. This report will primarily focus on the following non-battery ESS technologies: pumped hydro storage (PHS), flywheel ESS, and liquid and compressed air energy storage (LAES/CAES). These technologies were selected based on their proven utility-scale applications, their varying potential for different utility applications based on system characteristics, and their unique physical properties, distinguishing them from traditional BESS. Other technologies, such as supercapacitors, were excluded due to their current early development and deployment status. Some more developed technologies were also left out, as they are better suited for other industries, such as thermal energy storage, which is more effective for commercial heating and cooling systems than for electrical storage and distribution.[89]

[89] Sarbu, I. & Sebarchievici, C. (2018). A Comprehensive Review of Thermal Energy Storage. *MDPI*, 10(1), 191. https://doi.org/10.3390/su10010191

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Figure 36: Organization of Different ESS Technologies' Applications Based on Discharge Duration and System Power Rating

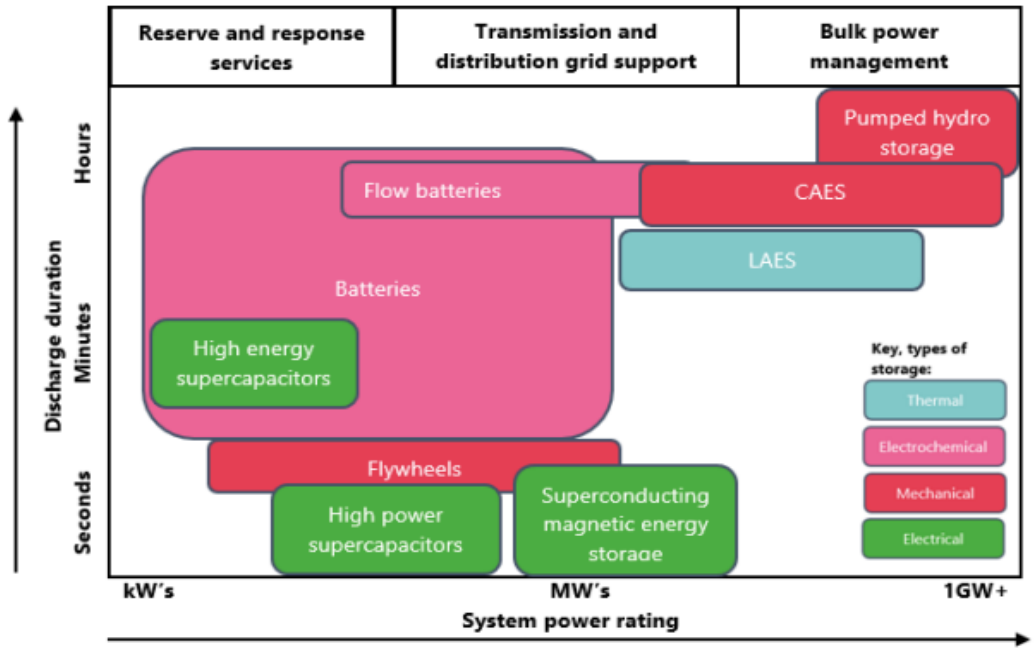


Figure 37: Comparison of Key Characteristics of Pumped Hydro, Flywheel, and Compressed Air ESS Technologies[1]

Properties	Flywheel	Compressed air	Pumped hydro
Specific power	High	Medium	Low
Specific energy	High	Medium	Low
Power density	High	Medium	Low
Energy density	High	Medium	Low
Lifespan	Low	Medium	High
Life-cycle	High	Low	Medium
Efficiency	High	Medium	Medium
Self discharge rate	High	–	–
Scale	Low	Medium	High
Maintenance	Low	Medium	Medium
Energy capital cost	High	Low	Low
Power capital cost	Low	Medium	High
Scale	Medium	High	High
Impact on environment	Extremely low	Medium to low	High to medium

19.0 *New Resource Option:* Pumped Hydro Storage (PHS)

19.1 Description

Pumped hydro storage (PHS) has historically been the most widely used energy storage technology worldwide, with the first projects appearing in Switzerland in the 1890s. Ninety-six percent of the U.S. utility-scale energy storage capacity is attributed to PHS, which translates to 22 GW of generation capacity and 553 gigawatt-hours (GWh) of storage capacity.[90] A PHS system consists of two water reservoirs at different elevations, with energy stored by using electricity to pump water from the lower reservoir to the higher one during low demand and low energy prices (i.e., storing energy). During peak demand, the water is discharged by releasing it to flow back to the lower reservoir, passing through a turbine generator to generate energy (i.e., discharging energy). The size of the reservoirs determines the storage capacity, while the size of the turbine generator determines the generation capacity. Systems can be designed with existing flowing water features (open-loop system) or artificially created reservoirs (closed-loop system). These systems provide about 80% round-trip efficiency, with approximately 10% of energy being lost while pumping water from the lower to the higher reservoir and another 10% lost as the water passes through the turbine to generate energy.[91]

PHS systems have been successfully integrated with renewable generation sources, such as wind and photovoltaics, to store and discharge energy as needed effectively. They represent a form of long-duration storage that offers greater discharge flexibility. Additionally, PHS systems are well-suited for black start services and frequency regulation due to their rapid charge and discharge capabilities and large generation capacity. Recent advancements in technology and system design have made PHS systems more modular and easier to deploy. Recent policies, such as the Inflation Reduction Act of 2022, offer guaranteed loan financing and grant funding, and extend the Production Tax Credit and the investment tax credit,[92] through 2023 and 2024—programs intended to increase the deployment of PHS systems.

The Pacific Northwest National Laboratory (PNNL), in partnership with the National Renewable Energy Laboratory (NREL), analyzed the potential for PHS systems in Puerto Rico as part of the Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100). However, barriers to further development and integration of these projects include the high capital costs associated with construction (which will be discussed further) and potential challenges related to project location, such as topographic requirements or construction complexity.

19.2 Technology Maturity

PHS systems are in the fourth stage of the technology adoption cycle (i.e., mature deployment), as this technology has been successfully used worldwide for decades to produce and store energy in bulk. According to the International Hydropower Association, as of 2022, there are 98 operational PHS projects globally, including 28 in the United States. The United States plans to build a new PHS facility

[90] US Department of Energy. (n.d.). Hydropower Market Reports. https://www.energy.gov/eere/water/hydropower-market-reports

91 Blakers, A., Stocks, M., Lu, B., Cheng, C. (2021). A Review of Pumped Hydro Energy Storage. *IOP Science*, Prog. Energy 3 022003. https://doi.org/10.1088/2516-1083/abeb5b

92 The White House. (2022). Building a clean energy economy: A guidebook to the Inflation Reduction Act's investments in clean energy and climate action. https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf

every year from 2022 to 2031, with Austria, China, and Germany also adding several new PHS facilities, with commissioning dates extending into 2034. These projects have generating capacities ranging from 50 MW to 2.8 GW.[93]

Across the global landscape, several projects operate on islands and within tropical and subtropical zones, such as the Philippines, indicating an established precedent of island utility applications. In the United States, PHS development has slowed considerably, with the most recently commissioned and operational PHS facility in 2012 and before that in the 1990s. However, 10 projects are planned and announced to be completed by the decade's end, with an average generating capacity of 525 MW. Under various modeled scenarios, PHS will add 16.2 GW of generation capacity and another 19.3 GW by 2050 (Figure 38).

Furthermore, in 2022, the NREL conducted a resource assessment for closed-loop PHS in the U.S., including Puerto Rico, to evaluate the geospatial potential of PHS. According to the report, due to factors such as Puerto Rico's urban density and limited elevation variance, only seven potential sites met the minimum requirements after least-cost optimization (Figure 39). Variables considered included several topographic and environmental factors, using Geospatial Information System (GIS) datasets from sources such as the National Hydrography Dataset, the U.S. Fish and Wildlife Service, and the Global Human Settlement Layer data. The report found that these seven potential PHS systems total 6 GWh of energy storage capacity, with the minimum cost being significantly higher than those found in other study areas at $2,829/kW (Figure 38).[94]

From a policy perspective, while many countries broadly include energy storage in their strategic energy plans and policies, very few explicitly mention PHS in legislation regarding their renewable energy goals and targets. A common issue in energy storage legislation is the lack of clear definitions and parameters, which can complicate or unnecessarily hinder the development of these projects. In the United States, while recent policies such as the Inflation Reduction Act have incentivized PHS development by making it eligible to generate investment tax credit, further explicit inclusion and promotion of PHS are crucial.

[93] Hydropower Association. (n.d.). Pumped storage tracking tool. https://www.hydropower.org/hydropower-pumped-storage-tool
[94] National Renewable Energy Laboratory (NREL). (2022). Closed-Loop Pumped Storage Hydropower Resource Assessment for the United States. https://www.nrel.gov/docs/fy22osti/81277.pdf

Table 44: Summary of the National Renewable Energy Lab's Site Analysis for Pumped Hydro Storage in Puerto Rico

	Lower Reservoirs	Upper Reservoirs
Total Identified	14,762	3,858
	Number Excluded	
National Hydrography Dataset flowlines	12,735	3,206
National Hydrography Dataset waterbodies	87	8
Environmental Systems Research Institute federal lands	24	27
Fish and Wildlife Service Critical Habitat	382	203
Environmental Systems Research Institute wetlands	266	101
Global Human Settlement Layer Urban Areas	7,402	1,415
Total Remaining	744	249
Number Paired	22	18
Remaining after least-cost optimization	7	7

Figure 38: Cumulative Installed Pumped Hydro Storage Capacity

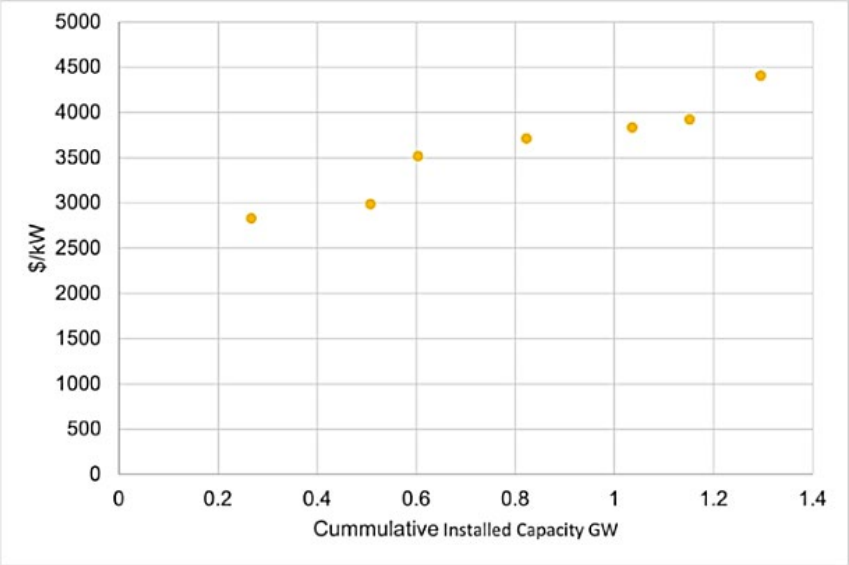
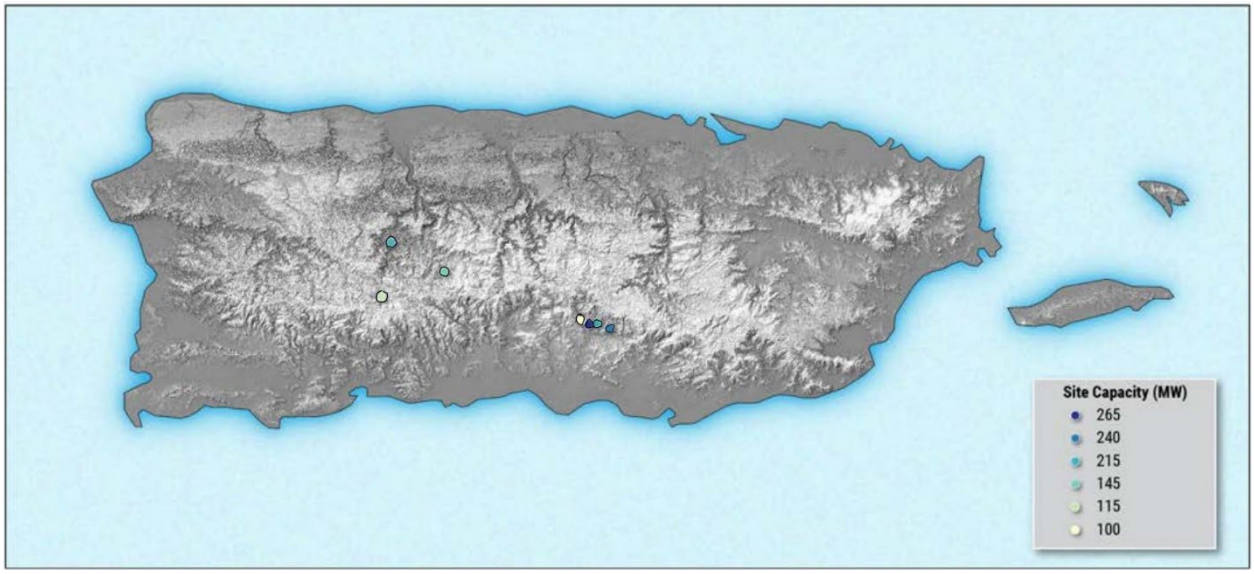


Figure 39: Map of Potential Pumped Hydro Storage Sites Identified by the National Renewable Energy Laboratory Study[94]



19.3 Cost

The capital costs and development timeline for a PHS project will vary depending on the plant's location, size, and environmental permitting requirements. A key factor influencing capital costs is the terrain and geography of the PHS site. Unlike other energy storage technologies, PHS projects are typically built at utility-scale capacities, significantly increasing overall costs. The permitting and construction timeline also plays a critical role in cost considerations, as it directly affects the facility's installation, operation, and maintenance expenses. Additionally, many proposed PHS projects fail to progress beyond the initial planning stages due to costly environmental requirements or stakeholder opposition. Capital costs for a 100 MW system could range between $2,044 and $2,625 per kW, while for a 1,000 MW system, the range is between $1,716 and $2,207 per kW (Table 45). Operation and maintenance (O&M) costs may vary between $28.19 and $15.60 per kW-year, depending on the facility's desired capacity. Levelized costs for PHS could range between $0.14 per kWh for a 10 MW system and $0.11 per kWh for a 100 MW system. [95] Variable O&M costs, which include refurbishment, labor, and parts replacement, are included in the total fixed O&M (Figure 40**).**

[95] Viswanathan, V., Mongird, K., Franks, R., Li, X. & Sprenkle, V. (2022). 2022 Grid Energy Storage Technology Cost and Performance Assessment. *Pacific Northwest National* Laboratory, Publication No. PNNL-33283. https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf

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Table 45: Installation and Operation Costs for Different Capacities of Pumped Hydro Storage Systems for the Years 2021 and 2030[95]

		100 MW				1,000 MW			
		4 hr.		10 hr.		4 hr.		10 hr.	
		2021	2030	2021	2030	2021	2030	2021	2030
	Reservoir construction and infrastructure ($/kWh)	$81	$81	$76	$76	$68	$68	$64	$64
	Powerhouse construction and infrastructure ($/Kw)	$742	$742	$742	$742	$623	$623	$623	$623
	Electromechanical ($/Kw)	$467	$467	$467	$467	$392	$392	$392	$392
	Contingency fee ($/Kw)	$511	$511	$656.33	$656.33	$429	$429	$551.67	$551.67
	Total installed cost ($/kWh)	**$511**	**$511**	**$262.53**	**$262.53**	**$429**	**$429**	**$220.67**	**$220.67**
	Total installed cost ($/kWh)	**$2,044**	**$2,044**	**$2,625**	**$2,625**	**$1,716**	**$1,716**	**$2,207**	**$22,207**
Operating costs									
	Fixed O&M ($/Kw-YR)	**$28.10**	**$28.10**	**$28.19**	**$28.19**	**$15.58**	**$15.58**	**$15.59**	**$15.59**

Figure 40: Total Installed Costs Range for Pumped Hydro Storage Systems with Different Capacities[95]

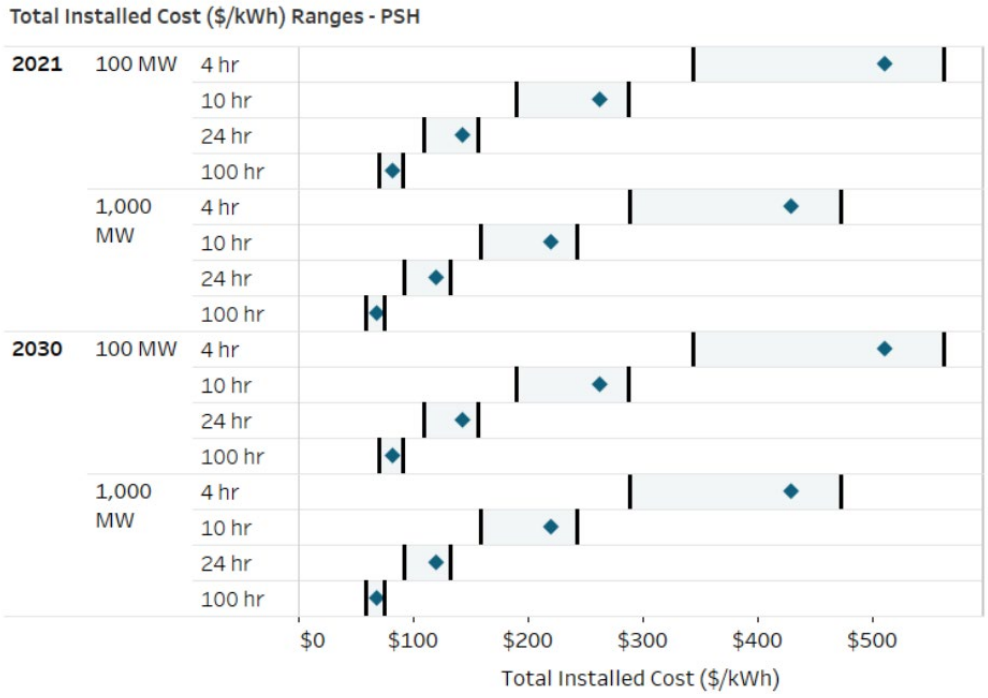


Table 46: Breakdown of the Operation and Maintenance Costs for 100- and 1,000-Megawatt Pumped Hydro Storage System

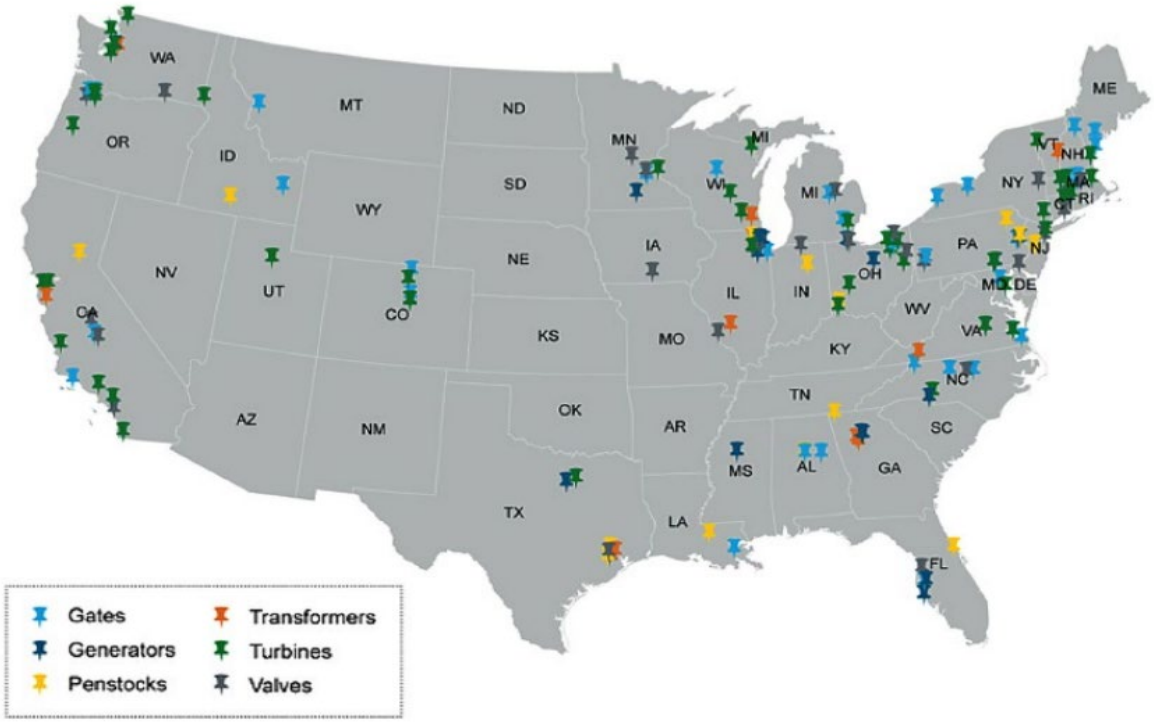
Fixed O&M Component	100 MW System	1,000 MW System
Labor related ($/kW-year)	$15.75	$3.15
Parts related ($/kW-year)	$5.59	$5.59
Refurbishments related ($/kW-year)	$6.85	$6.85
Total fixed O&M ($/kW-year)	**$28.19**	**$15.60**

19.4 Supply-Chain

The main components of a PHS system are the upper and lower reservoirs, a switchyard, a generator, and a turbine. The United States has a robust domestic manufacturing market for PHS components (Figure 41), which lessens the need to rely on foreign trade markets.[96]

[96] Uría-Martínez, R. (2022). Hydropower - Supply Chain Deep Dive Assessment. *U.S. Department of Energy*. https://www.energy.gov/sites/default/files/2022-02/Hydropower%20Supply%20Chain%20Report%20-%20Final.pdf

Figure 41: U.S. Suppliers and Manufacturers of Hydropower Plant Components[96]

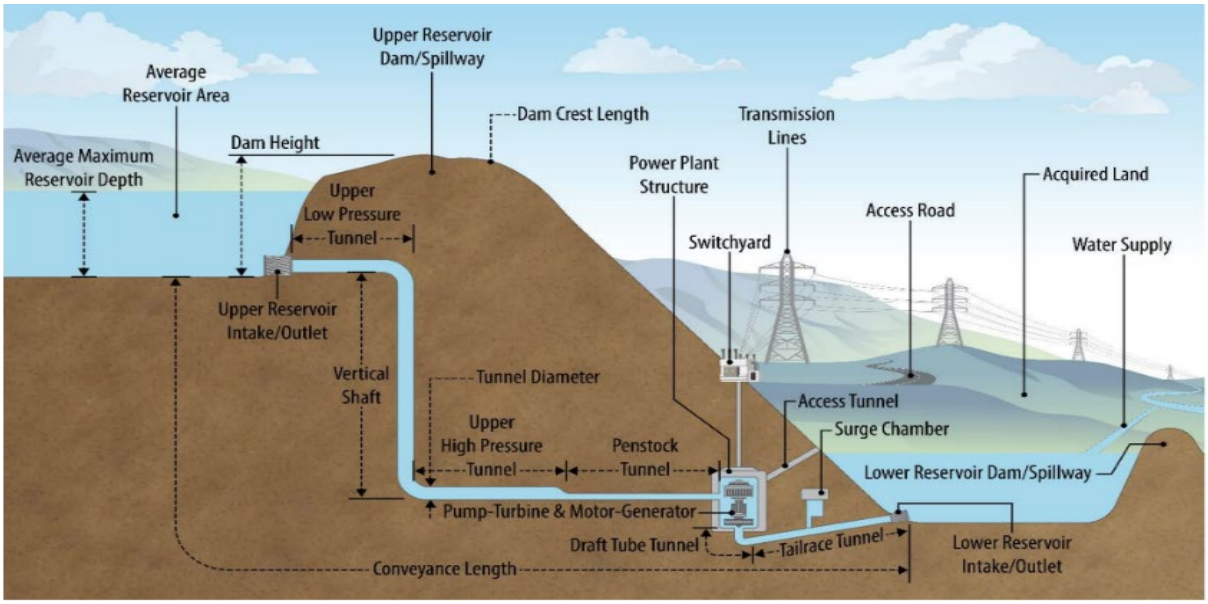


Water availability could pose the most significant constraint in adopting this storage technology. PHS systems depend on water as their only source of energy. Changes in energy policy could render this form of energy storage unviable and extremely difficult to operate. During drought, the water in the reservoirs may be needed for other purposes, posing a significant challenge for implementing this technology. The location and scale of the construction further limit the feasibility of PHS systems in Puerto Rico. The permitting and construction process for complex projects can be lengthy, often taking years.[97]

[97] Wilson, R. (2023). Addressing the risks of pumped storage hydropower for a net-zero world. *Lockton*. https://global.lockton.com/gb/en/news-insights/addressing-the-risks-of-pumped-storage-hydropower-for-a-net-zero-world

19.5 Construction and Development

Figure 42: Diagram of a Traditional Pumped Hydro Storage System[98]



Although PHS systems share similar key components, the construction of each system can vary depending on the specific project's application. Due to the typically large scale and topographic limitations of viable sites, the average industry commissioning time for a PHS system is about 10 years. Permitting and challenging construction processes contribute significantly to the lengthy timeline for PHS development (see Figure 42). Environmental and construction permitting and the development of the upper and lower reservoirs, water conveyances, and transmission interconnection components contributed the most to development time.[99] The Department of Energy (DOE) has actively invested in research to minimize the construction and commissioning timeline of these projects. Some solutions being explored in pilot phases of development include alternative layouts, modular dam concepts, and a medium-scale modular PHS system, which was researched as a part of the DOE's ground-level integrated diverse energy storage project.[100]

[98] Cohen, S., Ramasamy, V. & Inman, D. (2024). A Component-Level Bottom-Up Cost Model for Pumped Storage Hydropower. *National Renewable Energy Laboratory.* https://docs.nrel.gov/docs/fy23osti/84875.pdf

[99] Water Power Technologies Office. (2021). Halving the commissioning timeline for pumped-storage hydropower development—FAST Prize successfully produces promising technical solutions. *U.S. Department of Energy.* https://www.energy.gov/eere/water/articles/halving-commissioning-timeline-pumped-storage-hydropower-development-fast-prize

[100] Water Power Technologies Office. (2021). Low-cost, modular pumped-storage that can be installed anywhere—ORNL GLIDES project nears commercial readiness. *U.S. Department of Energy.* https://www.energy.gov/eere/water/articles/low-cost-modular-pumped-storage-can-be-installed-anywhere-ornl-glides-project

19.6 Operation

PHS offers exceptional longevity compared to other storage technologies, with an estimated 14,000 storage cycles over its lifetime[101] and an asset life exceeding 50 years. Operational maintenance labor is also relatively low, with a 2020 study estimating that a 1000 MW PSH plant would require fewer than 40 full-time workers, and labor costs would not significantly change as MW capacity increases. Additionally, due to its technological maturity, the learning curve is minimal. In terms of system repair and upkeep, repairs beyond routine maintenance are expected approximately every five years, with an estimated cost of 1% of electromechanical components. Major repairs, such as replacing seals on the turbine, would be required every 10 years, while rotor replacement and other significant repairs occur every 20 years, costing between 10%-20% of total electromechanical costs.[102]

19.7 Sustainability

A PHS system has several key benefits over traditional BESS and other non-battery technologies in terms of lifecycle sustainability. Due to the long lifespan of the facilities, and reduced reliance on rare earth minerals like nickel and cobalt for system components, no significant waste material is produced. Fossil fuel use depends on the source of electric generation applied to the system, but PHS systems are often collocated with renewable energy generation sources. This does not mean there are no sustainability concerns, chief among them being the ecologically invasive nature of the system's design. Conventional PHS systems utilize existing reservoirs or create new ones above ground, altering the area's natural hydrology and impacting local waterways. There are less invasive system designs, such as small PHS or underground PHS systems, which utilize existing mining caverns. Underground systems also reduce environmental damage due to less construction. In fact, NREL has recently conducted research indicating that PHS has the lowest global warming potential over its lifetime of any energy storage technology, with estimated lifecycle emissions between 58 and 502 grams of CO_2e per kWh.[103] As for water quality, literature indicates that some PHS systems can also function using wastewater and may even improve water quality by aerating it, becoming part of an aerobic biological water treatment process.[104]

[101] Krüger, K. (2021). Pumped storage hydropower capabilities and costs. *Pumped Storage Hydropower International Forum*, September. https://assets-global.website-files.com/64f9d0036cb97160cc26feba/64f9d0036cb97160cc2712aa_IFPSH%20-%20PSH%20Capabilities%20and%20Costs_15%20Sept.pdf

[102] Mongird, K., Viswanathan, V., Alam, J., Vartanian, C., Sprenkle, V. & Baxter, R.(2020). 2020 Grid Energy Storage Technology Cost and Performance Assessment. *U.S. Department of Energy*, Publication No. DOE/PA-0204 (December). https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

[103] National Renewable Energy Laboratory (NREL). (2023). News release: NREL analysis reveals benefits of hydropower for grid-scale energy storage. https://www.nrel.gov/news/press/2023/news-release-nrel-analysis-reveals-benefits-of-hydropower-for-grid-scale-energy-storage.html

[104] Yang, C. & Jackson, R.B. (2011). Opportunities and Barriers to Pumped-Hydro Energy Storage in the United States. *Renewable and Sustainable Energy Reviews*, 15 (1): 839–44. https://doi.org/10.1016/j.rser.2010.09.020

20.0 *New Resource Option:* Flywheel Energy Storage (FES)

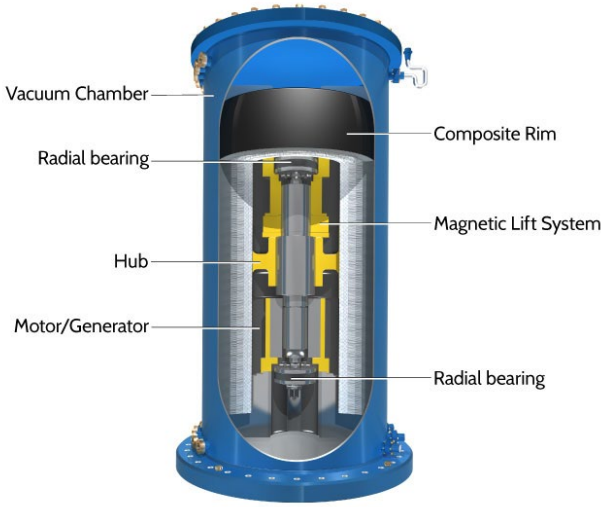
20.1 Description

Originally used for potters' wheels in the pre-industrial era and for various mechanical applications during the Industrial Revolution, flywheels were first employed as a method of energy storage in 1883. The flywheel, as a general concept, refers to the use of a large wheel, bearings, and an axle that allows the wheel to maintain high angular momentum, meaning it will continue to spin after force is exerted upon it. Flywheels are used in a variety of industries, ranging from industrial and automotive applications to energy generation (such as waterwheels). In a modern flywheel energy storage (FES) system, a dual-function motor and power electronic converter are integrated into this basic concept. The motor spins the flywheel when energy is input (charging), and when the motor is tuned off, the kinetic energy from the flywheel continues to spin the rotor, generating electricity for discharge (Figure 43). Since potential energy loss in this system primarily occurs due to a reduction in speed caused by friction, FES systems are housed in a small vacuum enclosure to reduce aerodynamic drag and are equipped with high-performance bearings (sometimes magnetic bearings) to minimize rotational friction. In these systems, flywheels can achieve up to 100,000 revolutions per minute and complete more than 150,000 charge and discharge cycles, allowing for lifespans of over 20 to 30 years.[105,106]

Due to their rapid charge and discharge response times, flywheels are most used for frequency stabilization and are often integrated with renewable energy generation.[3, 107] Flywheels are also highly efficient, with a range of 90-95%, depending on the system design. Their modularity and compact size allow them to be scaled to meet energy and power requirements based on the size of the motor/generator and other components. These systems have very low operation and maintenance costs, minimal efficiency degradation compared to traditional BESS and pose almost no environmental risk due to the absence of corrosive or hazardous materials and their limited spatial requirements. The primary challenges associated with flywheel technology include the high capital costs, which arise from the need for high-strength, low-density materials, short storage duration (with ideal storage lasting only tens of minutes[108]), safety concerns due to high rotational speed and risk of mechanical failure, and a high self-discharge rate. Although government-funded research on the application of flywheel technologies has been conducted, there is limited legislation supporting flywheel energy storage, aside from its eligibility 'for the Investment Tax Credit under the Inflation Reduction Act.

[105] Guo, Z., Ge, S., Yao, X., Li, H., & Li, X. (2019). Life cycle sustainability assessment of pumped hydro energy storage. *International Journal of Energy Research*, 44(1), 192–204. https://doi.org/10.1002/er.4890
[106] Koohi-Fayegh, S. & Rosen, M.A. (2020). A Review of Energy Storage Types, Applications and Recent Developments. *Journal of Energy Storage*, 27 (101047): 101047. https://doi.org/10.1016/j.est.2019.101047
[107] Ji, W., Hong, F., Zhao, Y., Liang, L., Du, H., Hao, J., Fang, F. & Liu, J. (2024). Applications of flywheel energy storage system on load frequency regulation combined with various power generations: A review. *Renewable Energy*, 223, 119975. https://doi.org/10.1016/j.renene.2024.119975
[108] Chen, H., Cong, T. N., Yang, W., Tan, C., Li, Y., & Ding, Y. (2009). Progress in electrical energy storage system: A critical review. *Progress in Natural Science*, 19(3), 291–312. https://doi.org/10.1016/j.pnsc.2008.07.014

Figure 43. Diagram of Beacon Power's Carbon Fiber Flywheel System, Which Spins Up to 16,000 Rotations per Minute and Can Perform More Than 175,000 Full-Depth Charge and Discharge Cycles[109]



20.2 Technological Maturity

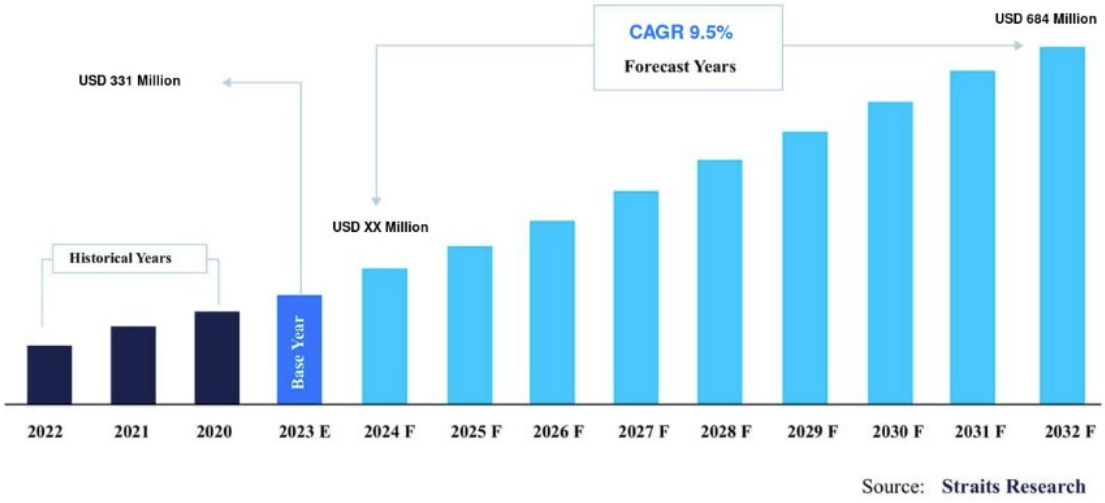
Regarding utility applications, FES systems are gaining momentum and demonstrating commercial viability within the US and worldwide, positioning them in the third stage of the technology adoption cycle (i.e., early commercial development). In the United States, Beacon Power is the commercial leader, with two 20 MW capacity projects located in Stephentown, New York, and Hazel Township, Pennsylvania, developed in partnership with the DOE as a part of the American Recovery and Reinvestment Act (ARRA)[110]. These projects, which reached entire commercial operation in 2011 and 2014, primarily provide frequency regulation services for the New York Independent System Operator (NYISO, a non-profit organization that manages New York's power grid and wholesale electricity markets) and Pennsylvania-New Jersey-Maryland Interconnection (PJM, a regional transmission organization that manages the electric transmission system for 13 states and the District of Columbia). According to Beacon Power's official website, the NY facility performs between 3000 and 5000 full-depth-of-discharge cycles per year, accounting for over 30% of area control error correction, with an accuracy rate exceeding 95%.[111] Other smaller-scale projects (1-5 MW) operate worldwide, including island territories, such as the Philippines and Hawaii. They are used for frequency management, renewable energy collocation, storage capacities, and other industries such as transportation and aerospace.[112]

Additionally, in 2019, the state of California created a research report on the commercial feasibility of FES for utility-scale energy storage in partnership with Amber Kinetics (flywheel manufacturer and developer). The report included market research, technical safety assessments, and economic impacts

[109] Beacon Power. (n.d.). Carbon Fiber Flywheels. https://beaconpower.com/carbon-fiber-flywheels/
[110] Staubly, R. & Rounds, R. (2012). Grid-Scale Flywheel Energy Storage Plan. *U.S. Department of Energy.* https://www.energy.gov/sites/prod/files/Beacon.pdf
[111] Beacon Power. (n.d.). Stephentown, New York. https://beaconpower.com/stephentown-new-york/
[112] Li, X. & Palazzolo, A. (2022). A Review of Flywheel Energy Storage Systems: State of the Art and Opportunities. *Journal of Energy Storage*, 46 (February), 103576. https://doi.org/10.1016/j.est.2021.103576

on ratepayers.[113] The results of this study proved Amber Kinetics' M32 Flywheel product's commercial readiness. It has since been deployed at various capacities worldwide.[114] Due to these developments and the growing need for coupling responsive ESS technologies with renewable generation, Straits Research has forecasted a compound annual growth rate of 9.5% globally by 2030 (Figure 44).[115]

Figure 44: Forecasted Global Market Growth of Flywheel Energy Storage Systems According to Straits Research[115]



20.3 Cost

Similar to PHS, the costs related to implementing and operating an FES system depend on the application and the system's capacity.[22] For example, for a 20 MW FES system, capital costs may range from approximately $600 to $2,400 per kW for systems between 0.3 MW and 20 MW (Figure 45). For a 20 MW FES system, the levelized storage cost is approximately $0.19 per kWh, while fixed O&M costs could be around $5.6 per kW-year. Additionally, variable O&M costs are estimated at $0.30 per MWh.[116,117]

[113] Sutherland, W., Senesky, M., Kwok, W., Stout, M., Sanders, S., Chiao, E. & Bhat, R. (2019). Flywheel Systems for Utility-Scale Energy Storage. *California Energy Commission*, CEC-500-2019-012 (January). https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2019-012.pdf

[114] Amber Kinetics. (n.d.). Installations. *Amber Kinetics*. https://amberkinetics.com/installations/

[115] Bothare, V. (2023). Global Flywheel Energy Storage Market Size, Share and Forecast 2033. *Straits Research*. https://straitsresearch.com/report/flywheel-energy-storage-market

[116] Mongird, K., Viswanathan, V., Balducci, P. Alam, J., Fotedar, V., Koritarov, V., Hadjerioua, B. (2019). Energy Storage Technology and Cost Characterization Report. *U.S. Department of Energy.* https://www.energy.gov/sites/default/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

[117] Rahman, Md Mustafizur, et al. The Development of a Techno-Economic Model for the Assessment of the Cost of Flywheel Energy Storage Systems for Utility-Scale Stationary Applications. *Sustainable Energy Technologies and Assessments*, (October). https://doi.org/10.1016/j.seta.2021.101382

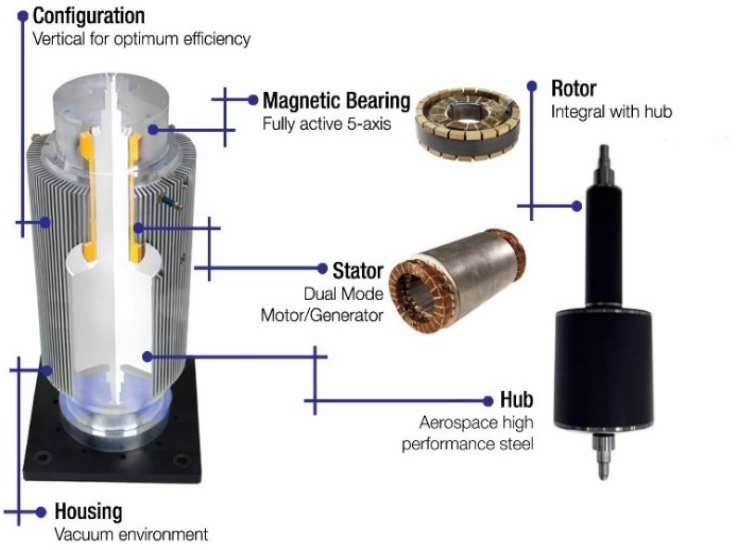
Figure 45: Capital Costs for Flywheel Energy Storage Systems with Different Capacities[116]

Capital Cost ($/kW)	Notes	Source
$2,400	20 MW/5 MWh Beacon Power flywheel plant	Aquino et al. (2017a)
$600	333 kW, 1.5 kWh system excluding installation	Goodwin (2018)
$1,050	1 MW, 0.0074 MWh system including installation	Helix Power (2018)

20.4 Supply Chain

Flywheels primarily consist of rotors, stators, magnetic bearings, and housing (Figure 46). This type of energy storage has a lifespan of 20 years, can undergo deep discharge with minimal degradation, and is made of environmentally safe materials.[118] Due to their higher energy density, composite materials, such as steel, graphite whiskers, epoxy, and carbon fibers, are primarily used to create FES systems.[119] Of all these materials, steel is the primary raw material used to construct FES systems.[120] Steel production is supported by a diverse global supply chain, with significant contributions from China, India, and Japan. However, due to slowing demand, declining profitability, and declining utilization, the reliability of steel supply can be limited in the future.[121]

Figure 46: Main Components of a Flywheel[122]



[118] Hu, D., et al. (2023). A review of flywheel energy storage rotor materials and structures. *Journal of Energy Storage*, 74(3), 109076. https://doi.org/10.1016/j.est.2023.109076

[119] Conteh, M. A. & Nsofor, E. C. (2016). Composite flywheel material design for high-speed energy storage. *Journal of Applied Research and Technology*, 14(3), 184–190. https://doi.org/10.1016/j.jart.2016.04.005

[120] Koohi-Fayegh, S. (2020). Flywheel Energy Storage - an Overview. *ScienceDirect*. www.sciencedirect.com/topics/engineering/flywheel-energy-storage

[121] Baroyan, A. & Kravchenko, O. (2023). The resilience of steel: Navigating the crossroads. *McKinsey & Company*, (April 18). https://www.mckinsey.com/industries/metals-and-mining/our-insights/the-resilience-of-steel-navigating-the-crossroads

[122] Jeter, J. (2021). Flywheel energy storage system basics. *EE Power*, (September 23). https://eepower.com/industry-articles/flywheel-energy-storage-system-basics/

20.5 Construction and Development

One of the benefits of FES systems is their small spatial footprint and relatively flexible system design, given their modularity. While different manufacturers may have variations in their system setup and components, systems generally include an enclosed flywheel system (Figure 46), partially embedded in the ground, connected to a power control system, and some cooling/fire suppression system. In addition, depending on the size and interconnection details of the project, systems may feature a local transformer and switchgear controller. The construction of these systems requires concrete pads for the power control systems and electrical components, while concrete foundations are poured to house the flywheel containers. According to Beacon Power, this system design requires low maintenance, and its technical specifications allow for operation in extreme conditions and climates, including the humidity of Puerto Rico. Other manufacturers, such as Amber Kinetics, also design their systems to withstand harsh environments, such as their PV-coupled FES project in the highlands of Tibet.[123] As part of Beacon Power's New York project, the DOE released a development timeline for the project, including permit acquisition and construction. Based on this timeline (Figure 47), the period from permit acquisition to operation was nine months, with additional storage capacity added over time.[110]

Figure 47: Projected Timeline of Beacon Power's 20 MW Flywheel Energy Storage Facility in New York, Provided by the Department of Energy[110]



20.6 Operation

Due to the relatively simple mechanical components and the reduced friction and resistance resulting from the system design and components, FES systems offer one of the highest depths of discharge

[123] Amber Kinetics. (2020). Only ruggedized energy storage solution. https://amberkinetics.com/installation/only-ruggedized-energy-storage-solution/

lifetime cycles, up to 150,000 cycles, and an asset life of 20-30 years.[124] For the same reasons, FES systems require relatively low maintenance. However, operationally, there is a strong emphasis on controlling rotor speed to maintain a stable direct current (DC) voltage. Depending on the characteristics of the deployed system, such as integration with another ESS technology, different control technologies may be employed, which can slightly affect system operation. Regardless of the control type, flywheel storage facilities typically do not require on-site personnel.

20.7 Sustainability

Due to their small size and modularity, FES systems do not pose the same spatial or environmental concerns as PHS. Consequently, the primary environmental impacts are from the operational phase. While construction materials may vary depending on system design, FES systems generally consist of various types of steel, copper, carbon fiber composites, iron, and some other materials for manufacturing the system components. Studies have examined the lifecycle emissions of FES systems, and while there is some variation depending on system structure and the paired electricity generation source, lifecycle GHG emissions typically range from 50 to 120 grams per kWh. The operational phase contributes 55% to 75% of the total lifecycle emissions, mainly from upstream emissions associated with renewable sources and electricity consumption in standby mode. FES systems are the most sustainable and environmentally friendly form of utility-scale energy storage when paired with available renewable energy sources. In the same study, researchers concluded that excluding the operational phase, Li-ion batteries have twice the GHG emissions per MWh than composite and steel rotor FES systems. Other electrochemical batteries fare even worse, such as lead-acid batteries, having almost 10 times the emissions of the FES systems. Higher GHG emissions stem from their short lifecycles and dependence on GHG-intensive chemicals and materials.[125]

[124] Choudhury, S. (2021). Flywheel Energy Storage Systems: A Critical Review on Technologies, Applications, and Future Prospects. *International Transactions on Electrical Energy Systems*, 31(9). https://doi.org/10.1002/2050-7038.13024

[125] Rahman, M. M., Gemechu, E., Oni, A. O., & Kumar, A. (2021). Energy and environmental footprints of flywheels for utility-scale energy storage applications. *e-Prime - Advances in Electrical Engineering Electronics and Energy,* 1, 100020. https://doi.org/10.1016/j.prime.2021.100020

21.0 *New Resource Option: Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES)*

21.1 Description

Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES) are two different technologies, with CAES being the more developed and proven technology. Both are based on the fundamental principles of compression and heat exchange and fall under the category of thermo-mechanical energy storage.

Engineers first developed the CAES system for industrial purposes in the 1960s. A CAES system operates very similarly to a traditional gas turbine system by taking in and compressing air, which then combines with some fuel (typically natural gas) to ignite. This process creates high-pressure and high-velocity gas that spins a turbine to produce electricity. As shown in Figure 48, the key difference between these two systems is that a CAES system uses an underground pressurized reservoir to store the air before combustion. In this design, the system uses electricity to pump air into the reservoir during charging periods. During discharge, the system combines the pressurized air with combustible fuel and ignites it, similarly to a gas turbine, to generate electricity. Another CAES system design, called adiabatic compressed air energy storage (A-CAES), recovers thermal energy during air compression and reuses it during the combustion/expansion stage.

LAES systems apply thermal compression and expansion concepts, with cryogenically cooled liquid air as the storage medium. In this system, electricity purifies, compresses, and cools ambient air during the charging cycle until it reaches a liquid state. The system stores the resulting fluid in a pressure vessel, similar to a CAES system. During discharge, it heats, evaporates, and then passes the liquid through turbines to generate electricity. Importantly, the cooling and reheating processes create excess hot and cold energy streams, which the system can reuse during charging and discharging cycles to improve efficiency (Figure 49). Given this technology's early development stage (see next section), various system configurations exist, including standalone LAES (without external inputs) and hybrid LAES (which utilize fuels for combustion).

Figure 48: Diagram of Basic Compressed Air Energy Storage Operation (Right) Compared to a Gas Engine (Left) [126]

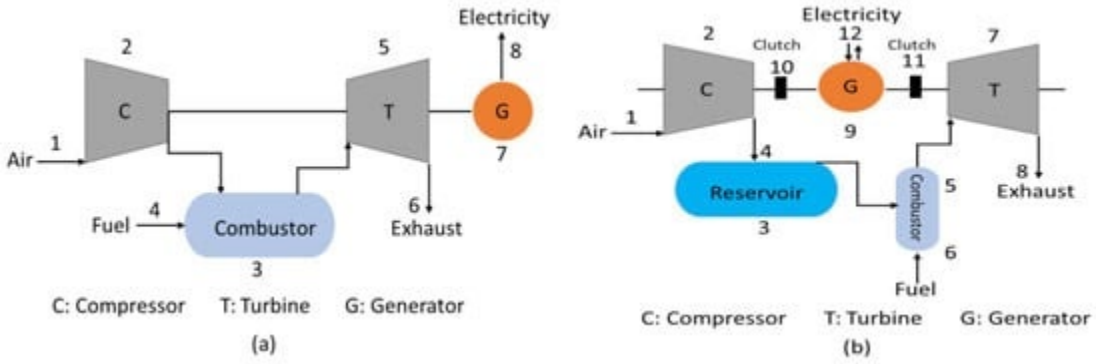
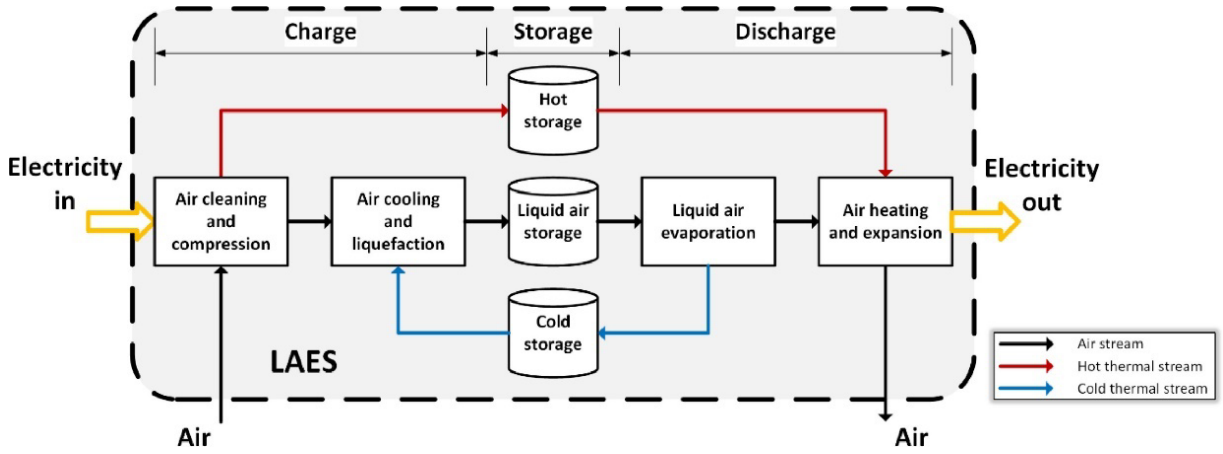


Figure 49: Diagram of the Operation of a Liquid Air Energy Storage System [127]



In both cases, LAES and CAES provide significant benefits compared to traditional energy storage technologies. Both system types have a large storage capacity, reaching up to 1000 MWh depending on the reservoir size, with storage durations of up to 24 hours and rapid ramp rates of up to 30% of maximum load per minute.[128] Furthermore, CAES and LAES have long asset lives of over 60 years despite relatively low 20,000 depth of discharge lifetime cycles in the case of CAES.[129] These features make these technologies viable for black start capabilities, peak shaving, and renewable integration since energy is generated during off-peak times, such as at night, from wind generation facilities, or afternoon solar generation. However, one of the most notable downsides is the lower round-trip efficiency, between 40% and 55%, depending on the system design, low lifetime charging cycles, and

[126] Rabi, A. M., Radulovic, J., & Buick, J. M. (2023). Comprehensive review of compressed air energy storage (CAES) technologies. *Thermo*, 3(1), 104–126. https://doi.org/10.3390/thermo3010008

[127] Vecchi, A., Li, Y., Ding, Y., Mancarella, P., & Sciacovelli, A. (2021). Liquid air energy storage (LAES): A review on technology state-of-the-art, integration pathways and future perspectives. *Advances in Applied Energy*, 3, 100047. https://doi.org/10.1016/j.adapen.2021.100047

[128] Olabi, A. G., Tabbi Wilberforce, M. R., Mohamad Ramadan, M. A., & Abdul Hai Alami, A. (2021). Compressed air energy storage systems: Components and operating parameters – a review. *Journal of Energy Storage*, 34 (February), 102000. https://doi.org/10.1016/j.est.2020.102000

[129] Ahmed, S., Flowers, D. L., & Balducci, P. J. (2023). Technology strategy assessment findings from Storage Innovations 2030 compressed air energy storage. *U.S. Department of Energy*. https://www.energy.gov/sites/default/files/2023-07/Technology%20Strategy%20Assessment%20-%20Compressed%20Air%20Energy%20Storage_0.pdf

siting constraints due to the need for a subterranean cavern in the case of CAES. Adiabatic systems that recycle excess heat/cold energy can reach up to 70% efficiency. However, it still falls short compared to other technologies.[130]

Table 47: 2030 Cost and Performance of Compressed Air Energy Storage, Assuming No Marginal Increase in Industry Investment[95,130]

Parameter	Value	Description
CAES system calendar life	60	Deployment life (years)
Cycle life	20,805	Base total number of cycles
Round-trip efficiency (RTE)	52%	Base RTE
Turbine, compressor, balance of plant, and engineering, procurement, and construction (EPC)	1,153	Base capital costs for compressor, balance of plant, and EPC ($/kW)
Cavern storage	6.84	Base cavern storage cost ($/kWh)
O&M costs	16.12	Base fixed O&M ($/kW-year)

21.2 Technology Maturity

A limited number of CAES and LAES facilities have been installed worldwide, serving as utility-scale case studies to assess these technologies' long-term effectiveness and performance. The two oldest facilities are the 321 MW CAES project in Germany and a 110 MW project in McIntosh, Alabama, installed in 1978 and 1991, respectively. Both systems are diabatic (requiring natural gas for combustion) and utilize underground salt caverns to store compressed air at pressures ranging from 43-70 bars.[129, 131] More recent systems, such as the 2011 2 MW A-CAES system in Texas, utilize a design that uses no natural gas and can be coupled with renewable generation sources like wind turbines. For LAES, two successful pilot projects with capacities of 250 kW and 5 MW have been completed. Several utility-scale projects, including a 50 MW commercial plant in the UK, are under construction, and additional utility-scale facilities in Japan and Australia are being developed with an operational target of 2025.[132] Currently, LAES is in the second stage of the technology adoption cycle (i.e., operational demonstrations), with ongoing advancements in commercialization and system design, while CAES has progressed further into the third stage (i.e., early commercial development).

CAES has been proven commercially, and the DOE is exploring potential pathways to reduce costs and improve system design through consultations with subject matter experts and industry representatives, as outlined in their Technology Strategy Assessment report for CAES.[129] The experts identified several key innovations based on this research and outlined preferred investment mechanisms for each (Table 48). This survey of industry representatives demonstrates the primary hurdles to improving system design and operation, namely technical research and further funding. As these technologies continue to evolve to meet current utility demands, and assuming sustained U.S. government investment, CAES is expected to become increasingly viable as a reliable energy storage technology solution.

[130] Rabi, A. M., Radulovic, J., & Buick, J. M. (2023). Comprehensive review of compressed air energy storage (CAES) technologies. *Thermo*, 3(1), 104–126. https://doi.org/10.3390/thermo3010008
[131] Jafarizadeh, H., Soltani, M., & Nathwani, J. (2020). Assessment of the Huntorf compressed air energy storage plant performance under enhanced modifications. *Energy Conversion and Management*, 209(April), 112662. https://doi.org/10.1016/j.enconman.2020.112662
[132] Highview Power. (2024). *Projects*, (May 30). https://highviewpower.com/projects/#inter-projects

Table 48: Identified Compressed Air Energy Storage System Innovations and Preferences for Investment Mechanisms Based on Small and Medium Enterprise Polling[129]

Innovation	National Laboratory Research	Research and Development Grant	Loans	Technical Assistance
Supply chain analytics	80%	0%	0%	20%
Mechanical compression/expansion	35.7%	50%	7.1%	7.1%
Lower temperature turbines	12.5%	50%	25%	12.5%
Compressed air and hydrogen energy storage systems	12.5%	62.5%	12.5%	12.5%
Hydraulic compression/expansion	28.6%	71.4%	0%	0%
Technologies for subsurface evaluation of porous rock for storage	33.3%	44.4%	11.1%	11.1%
Alternative approaches to high-temperature thermal storage	44.4%	44.4%	0%	11.1%
Alternative approaches to storing compressed air	30.8%	46.2%	7.7%	15.4%
Advanced heat exchanger technologies	36.4%	45.5%	18.2%	0%
Advanced pressure regulation technologies	42.9%	57.1%	0%	0%
Advanced manufacturing techniques	33.3%	33.3%	16.7%	16.7%
Advanced alloys	50%	37.5%	12.5%	0%
Novel materials for lining wells for storage	22.2%	33.3%	33.3%	11.1%
Organic phase change materials	50%	50%	0%	0%
System modeling and design/operation	33.3%	41.7%	8.3%	16.7%
Demonstration projects	14.3%	38.1%	33.3%	14.3%

21.3 Cost

Capital costs for a CAES system could range from $1,087 to $1,639 per kW for systems capacities of 100 MW or 1,000 MW, while fixed and variable O&M costs range from $9.82 to $18.56 per kW-year, depending on the storage duration (Table 49). The LCOS for CAES systems within these capacities may range from $0.15 per kWh to $0.18 per kWh, respectively.[133] For LAES systems with capacities of 10 MW and 1,000 MW, fixed O&M costs range from $15 to $30 per kW-year, while capital costs are estimated between $1,600 and $1,278 per kW.[133] The LCOE for these systems may vary between $0.22 and $0.18 per kWh. [134]

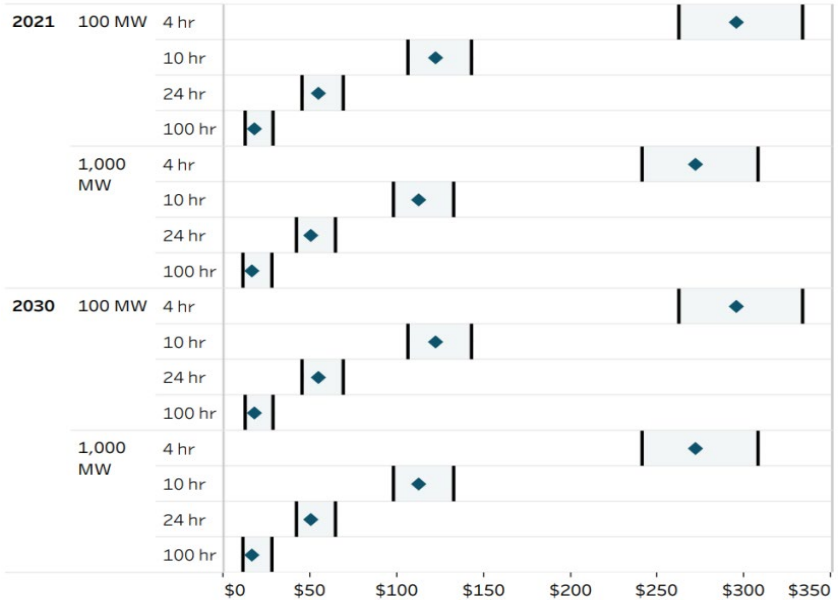
[133] Baxter, R., & Viswanathan, V. (2022). 2022 Grid energy storage technology cost and performance assessment. *Pacific Northwest National Laboratory (PNNL).* https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf

[134] Salem, A.M. & Khaira, A.M. (2023). A Mini-Review on Liquid Air Energy Storage System Hybridization, Modelling, and Economics: Towards Carbon Neutrality. *Royal Society of Chemistry*, pp. 26380–26391, (September 4). https://doi.org/10.1039/d3ra04506d

Table 49: Installation and Operating Costs for Different Capacities of Compressed Air Energy Storage Systems for the Years 2021 and 2030[133]

	100 MW								1,000 MW							
	4 hr.		10 hr.		24 hr.		100 hr.		4 hr.		10 hr.		24 hr.		100 hr.	
	2021	2030	2021	2030	2021	2030	2021	2030	2021	2030	2021	2030	2021	2030	2021	2030
Cavern storage ($/kWh)	$7.05	$7.05	$6.84	$6.84	$6.31	$6.31	$6.52	$6.52	$6.31	$6.31	$6.31	$6.31	$6.11	$6.11	$5.78	$5.78
Turbine, compressor, BOP, and EPC Management ($/Kw)	$1153	$1153	$1153	$1153	$1153	$1153	$1153	$1153	$1061	$1061	$1061	$1061	$1061	$1061	$1061	$1061
Total Installed Cost ($/kWh)	$295.30	$295.30	$122.14	$122.14	$54.68	$54.68	$17.84	$17.84	$271.77	$271.77	$112.41	$112.41	$50.32	$50.32	$16.39	$16.39
Total Installed Cost ($/kW)	$$1181	$1181	$1221	$1221	$1312	$1312	$1784	$1784	$1087	$1087	$1124	$1124	$1208	$1208	$1639	$1639
Operation Costs																
Fixed O&M ($/Kw-YR)	$16.11	$16.11	$16.12	$16.12	$16.22	$16.22	$18.56	$18.56	$9.82	$9.82	$9.82	$9.82	$9.93	$9.93	$10.04	$10.04

Figure 50: Total Installed Cost Range in $/kWh for Compressed Air Energy Storage Systems with Different Capacities[133]



21.4 Supply Chain

CAES and LAES will be limited , like the PHS system, mostly to the location selected for implementing the storage facility rather than the components necessary for its fabrication. This type of energy storage has limited supply chain concerns as it uses widely available equipment and materials.[135] As previously mentioned, the main constraint for constructing these types of energy storage systems will be their geographic location. Salt caverns, artificial caverns, and high-pressure metal containers are the primary storage methods for the CAES and LAES systems.[136]

In Puerto Rico, candidate sites for this technology are limited, as most caverns are national parks and protected areas. A potential option for Puerto Rico could be to convert inoperable generation locations into smaller-scale energy storage system locations at generation facilities such as Cambalache unit 1.

21.5 Construction and Development

The primary constraints for developing a CAES facility are the size and site requirements for the pressurized air storage cavern. For small-scale CAES (less than 10 MW), above-ground storage tanks can be used and present minimal site constraints. However, large-scale CAES requires an existing geological cavern, significantly limiting viable project locations. Based on existing projects, the construction phases of CAES systems typically take around three years due to the scale of the

[135] Mann, M., Putsche, V., Shrager, B. (2022). Grid energy storage: Supply chain deep dive assessment. *U.S. Department of Energy*, (February 24). https://www.energy.gov/sites/default/files/2022-02/Energy%20Storage%20Supply%20Chain%20Report%20-%20final.pdf

[136] Stepanek, J. & Minkley, W. (2024). Thermodynamic analysis of compressed CO_2 energy storage in salt caverns with gravel stabilization. *ScienceDirect*. https://www.sciencedirect.com/science/article/pii/S2352152X2400094X

project,[137] with permitting and licensing timelines varying depending on the location. Additionally, because CAES projects require some form of fuel input for combustion, they are often co-located with natural gas power plants.

21.6 Operation

Large operational facilities have demonstrated high operational reliability, and operational costs do not significantly increase with more frequent charging and discharging cycles. Fewer major maintenance events over the system's lifetime have also been observed, although equipment upgrades and retrofits are not uncommon. For example, the Huntorf facility in Germany underwent significant mechanical modifications to increase net output power and incorporate technologies that were not available during its initial 1978 construction. These retrofits included the addition of a recuperation unit and turbo expander to repurpose waste heat, compressor cooling, steam injection, and water injection to expand the range of low- and high-pressure turbine inlet temperatures (LPTIT/HPTIT). As a result, the HPTIT decreased from 550 to 490 degrees Celsius (with no change in inlet pressure), LPTIT pressure increased from 10 bar to 12.8 bar, and the temperature rose from 825 to 945 degrees Celsius.[131] Additionally, in 2000, retrofits were implemented at the McIntosh facility in Alabama to enhance reliability and reduce operational costs, including redesigning the LP expander's combustor, fuel injector, and ignitor.[138] CAES systems' long lifespan enables continuous performance improvements through upgrades while maintaining relatively low operational costs.

21.7 Sustainability

CAES and LAES have more environmental concerns than many other energy storage technologies, primarily due to some system designs' reliance on natural gas combustion for energy discharge. The combustion of natural gas for CAES produces 50.3 kg CO_2e per GJ of gas consumed, with the heat rate varying depending on various system factors.[139] Based on the same 2003 study, lifecycle GHG emissions for a CAES project are about 292 tons CO_2e per GWh, with a majority coming from the transportation and combustion of natural gas (Figure 51). This study assumed a salt cavern for storage, a 20% capacity factor, and an equipment life of 40 years. It used a facility proposed in Norton, Ohio, as a model, which has a peak output of 2700 MW and an energy/power ratio of 16 hours. This leads to the estimated 0.735 GWh of electricity required to produce 1 GWh from the facility, in addition to 5270 GJ of thermal energy, of which 10% is for natural gas transportation. For LAES, estimations for a 20MW system assuming a 15% utility rate and a system average fuel mix for charging show lifetime emissions of about 0.02 kg CO_2e/kWh.[140] Aside from air pollution, these systems do not produce additional waste besides potential heat/cold energy. The only other environmental considerations would be the potential damage to ecosystems for the land disturbance required to optimize subterranean caverns for pressurized air storage, which often involves the dissolution of a salt dome to satisfy operating

[137] Matos, C.R., Silva, P.P., Carneiro, J.F. (2022). Overview of Compressed Air Energy Storage Projects and Regulatory Framework for Energy Storage. *Journal of Energy Storage*, Vol. 55 Part D (November 30): 105862. https://doi.org/10.1016/j.est.2022.105862

[138] Holden, P., Moen, D., DeCorso, M. & Howard, J. (2000). Alabama electric cooperative compressed air energy storage (CAES) plant improvements. *ASME Turbo Expo 2000: Power Generation Conference* (p. 1-8). https://asmedigitalcollection.asme.org/GT/proceedings-abstract/GT2000/78569/V003T02A021/246000

[139] Denholm, P. & Kulcinski, G. L. (2004). Life cycle energy requirements and greenhouse gas emissions from large-scale energy storage systems. *Energy Conversion and Management*, 45(13-14), 2153–2172. https://doi.org/10.1016/j.enconman.2003.10.014

conditions. However, these environmental impacts are still less than those of similar-sized fossil fuel combustion facilities.[141]

Figure 51: Estimated Lifecycle Energy Consumption and Greenhouse Gas Emissions for Compressed Air Energy Storage Facilities[142]

	Life cycle energy	GHG emissions (CO_2e)
Fixed components		
Construction––EE_S, EM_S	266 GJ_t/MWh storage capacity	19 tonnes/MWh storage capacity
Variable components		
Fuel	4649 GJ_t/GWh	234 tonnes/GWh
Fuel delivery	518 GJ_t/GWh	51 tonnes/GWh
O&M&SCR	42 GJ_t/GWh	3 tonnes/GWh
Total variable––EE_{op}, EF_{op}	5210 GJ_t/GWh	288 tonnes/GWh
ER_{net}	0.735 times primary energy	0.735 times source emissions

[141] Bouman, E. A., Oberg, M.M. & Hertwich, E.G. (2013). Life Cycle Assessment of Compressed Air Energy Storage (CAES). *Industrial Ecology Programme, Department of Energy and Process Engineering, Norwegian University of Science & Technology (NTNU)*, Høgskoleringen 5, NO-7491 Trondheim, Norway. conferences.chalmers.se/index.php/LCM/LCM2013/paper/download/673/271

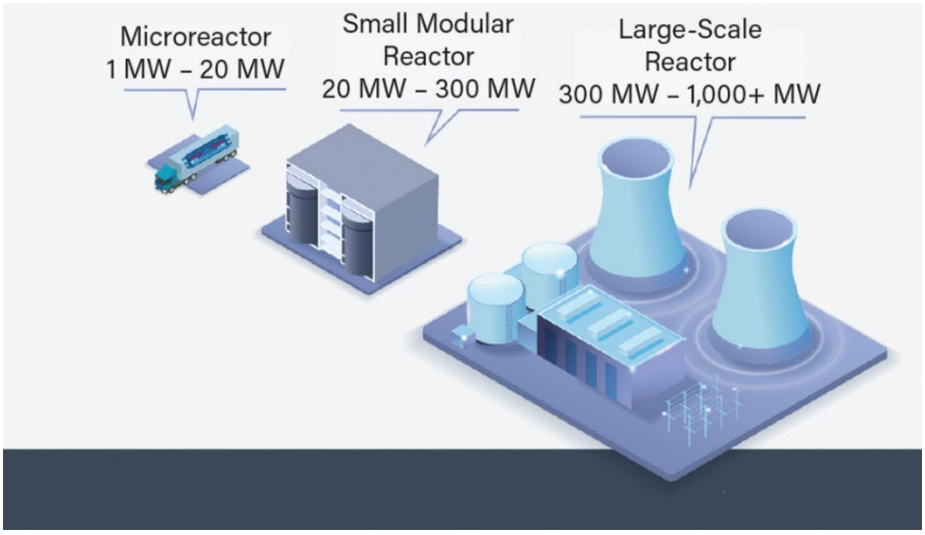
[142] Holden, P., Moen, D., DeCorso, M. & Howard, J. (2000). Alabama electric cooperative compressed air energy storage (CAES) plant improvements. In *ASME Turbo Expo 2000: Power Generation Conference* (p. 1-8). https://asmedigitalcollection.asme.org/GT/proceedings-abstract/GT2000/78569/V003T02A021/246000

22.0 *New Resource Option: Small Modular Reactors (SMRs)*

22.1 Description

Small modular reactors (SMRs) represent a significant advancement in nuclear power technology. These reactors are designed to be smaller and more modular than traditional nuclear power plants, offering several advantages over their larger counterparts. SMRs are nuclear fission reactors with a maximum electric output of 300 MW, while a traditional large nuclear reactor can produce over 1,000 MW. Their designs may employ light water as a coolant or non-light water coolants such as gas, liquid metal, or molten salt. The modular design of SMRs allows them to be built in factories, transported to various locations, and installed relatively quickly.[143] Figure 52 illustrates the relative size difference between the SMRs and the traditional nuclear power plants.[144]

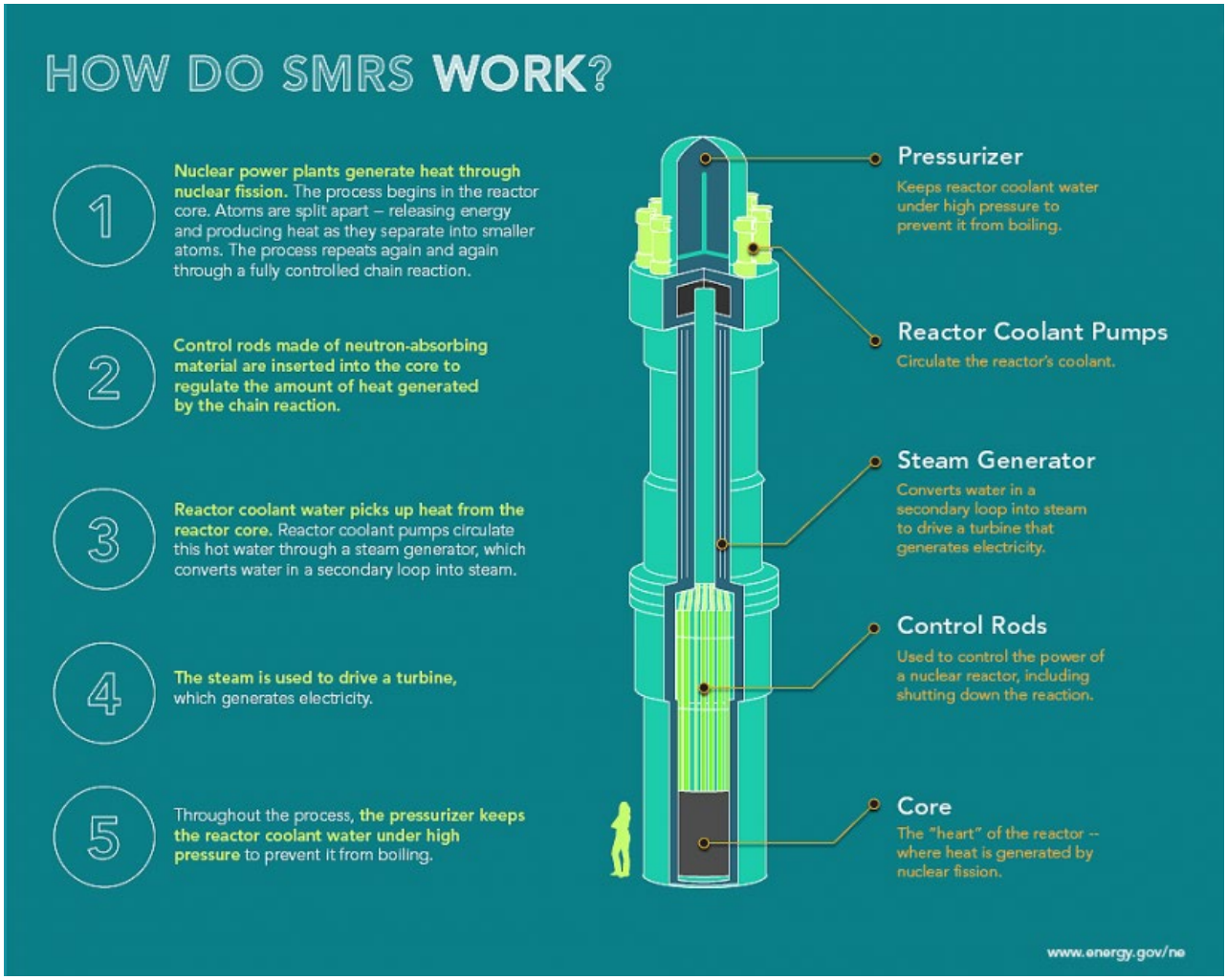
Figure 52: Size Differences Between the Nuclear Reactor Types[145]



Like traditional nuclear power plants, SMRs generate electricity through nuclear fission. However, SMRs are smaller, modular, and often incorporate passive safety features. Nuclear fuel rods are placed in the reactor core, where neutrons bombard the fuel, causing fission and releasing heat. A coolant circulates through the core, absorbing the heat and transferring it to a heat exchanger. This heat produces steam, which spins a turbine connected to a generator, generating electricity. Figure 53 shows the parts of the SMRs and their use in the process of generating electricity.[146]

[143] Liou, J. (2021). What are Small Modular Reactors (SMRs)? *International Atomic Energy Agency*, (November 4). https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs
[144] Insights Editor (2023). *Small Modular reactors (SMRs). Insights IAS*, (July 19). *https://www.insightsonindia.com/2023/07/19/small-modular-reactors-smrs/*
[145] See: https://www.researchgate.net/figure/Figura-5-Comparativo-de-potencia-eletrica-entre-tres-tipos-de-reatores-nucleares-Micro_fig1_384972435
[146] Nuclear | Electricity | 2024 | ATB | NREL. (n.d.). *National Renewable Energy Laboratory.* https://atb.nrel.gov/electricity/2024/nuclear

Figure 53: How Do Small Modular Reactors Work?[147]



SMRs offer several advantages, including lower capital investment due to modular design and factory fabrication, greater siting flexibility for various locations, enhanced safety and security features, and the potential to drive economic growth through job creation and increased manufacturing. SMRs can also be coupled with other energy sources to improve efficiency and grid stability. Additionally, their modular nature allows for incremental scaling and reduced construction times compared to traditional nuclear power plants. [148]Conversely, SMRs face several challenges, including unproven technology, potentially higher costs, regulatory hurdles, supply chain issues, and public perception.

Following Hurricane Maria, the State Legislature passed Resolution 1189 to officially evaluate SMRs for Puerto Rico. Due to the relatively few developed SMR projects worldwide, it is recommended that the new Public Energy Policy continue the established direction of prioritizing renewable sources integration, especially in the short term, rather than making significant adjustments based on emerging SMR

[147] https://www.energy.gov/ne/articles/4-key-benefits-advanced-small-modular-reactors
[148] Office of Nuclear Energy. (n.d.). Benefits of small modular reactors (SMRs). *U.S. Department of Energy*. https://www.energy.gov/ne/benefits-small-modular-reactors-smrs

technology.[149] Examples of countries implementing this technology are the United States, the UK, Canada, Japan, and South Korea. Russia and China connected their first SMRs to the grid in 2019 and 2021, respectively. [150]

22.2 Technology Maturity

Building on the successes of the SMR Licensing Technical Support program, the Advanced SMR Research & Development program was initiated in FY2019 and supports research, development, and deployment activities to accelerate the availability of U.S.-based SMR technologies into domestic and international markets. Significant technological development and licensing risks remain in marketizing advanced SMR designs. Government support is required to achieve domestic deployment of SMRs by the late 2020s or early 2030s. [151]

The technology adoption cycle identifies the stage of adoption for a specific technology. Due to the limited number of operational projects, SMRs could be classified as being in the second maturity stage (i.e., Operational Demonstration).

The most mature SMR concepts are based on light water reactors (LWR) technology. Other concepts are Generation IV reactors incorporating alternative coolants (i.e., liquid metal, gas, or molten salts) and advanced fuels. SMR deployment can vary between single-unit installations, multi-module plants, or mobile power sets such as floating (i.e., barge-mounted) units. In 2018, the International Atomic Energy Agency identified more than 50 concepts under development with different technology and licensing readiness levels, including four concepts under construction at the time.

Figure 54 shows the map where these concepts are being developed.

Only two SMR projects are operational in Russia and China. Table 50 shows their capacity, grid interconnection date, and commercial operation date. SMRs under construction are shown in Table 51.

Table 50: Current Small Modular Reactors in Operation

Unit (country)	Capacity	Grid Interconnection Date	Commercial Operation Date
Akademik Lomonosov 1 & 2 (Russia)	70 MW (2x35 MW)	December 2019	May 2020
Shidaowan HTR-PM 1 (China)	150 MW	December 2021	December 2023

Table 51: Current Small Modular Reactors Under Construction

Unit (country)	Estimated Capacity	Estimated Grid Interconnection Date
Brest-OD 300 (Russia)	300 MW	2026
ACP 100 Linglong One (China)	125 MW	2026

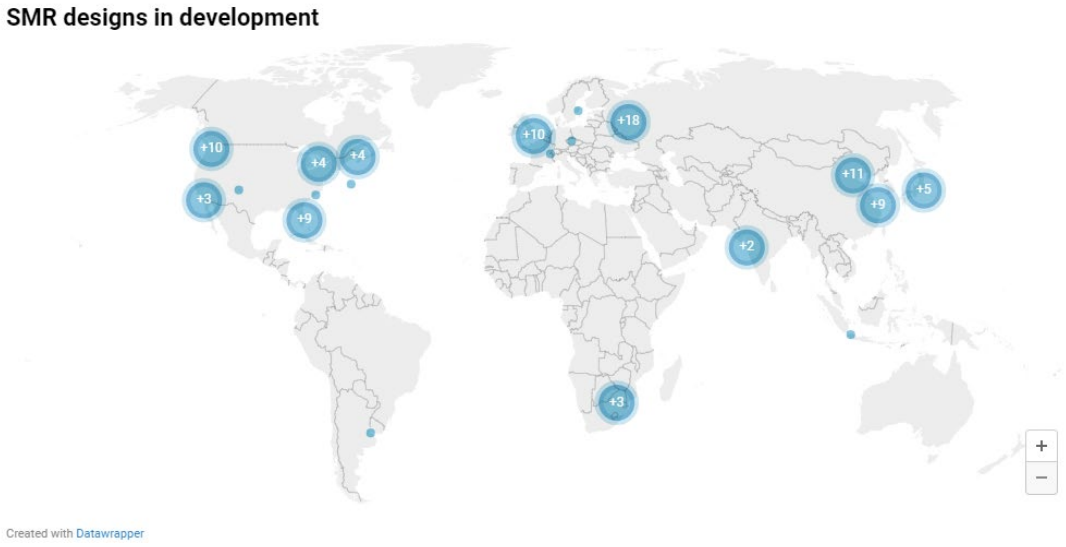
[149] Resolución de la Cámara 1189, RC 1189, 18va Asamblea 5ta Sesión. (2019). https://pluralpolicy.com/app/legislative-tracking/bill/details/state-pr-2017_2020-rc1189/437839

[150] European Union. (2024). Small Modular Reactors. *European Commission*. https://energy.ec.europa.eu/topics/nuclear-energy/small-modular-reactors/small-modular-reactors-explained_en#:~:text=As%20their%20systems%20and%20components,a%20location%2C%20reducing%20installation%20costs

[151] NuScale Power, LLC. (n.d.). Advanced Small Modular Reactors (SMRs). *U.S. Department of Energy*. https://www.energy.gov/ne/advanced-small-modular-reactors-smrs

Unit (country)	Estimated Capacity	Estimated Grid Interconnection Date
***Central Argentina de Elementos Modulares* (Argentina)**	25 MW	2028
Cape Nagloynyn 1 and 2 (Russia)	100 MW (2x50 MW)	TBD

Figure 54: Current Small Modular Reactors in Development[152]

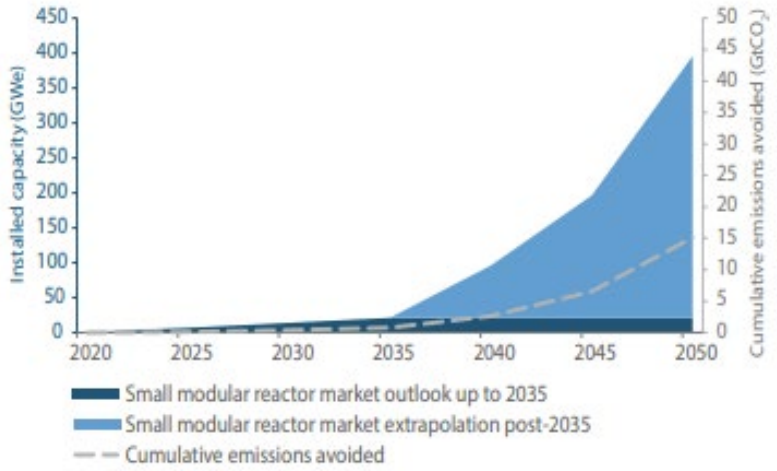


22.3 Promising Growth of Small Modular Reactors Technology

The Nuclear Energy Agency (NEA) estimates that the global SMR market could reach 21 gigawatts by 2035. A significant acceleration in the build rate is achievable by constructing 50 to 150 gigawatts per year. Assuming a build rate of 75 gigawatts per year by 2050, up to 375 gigawatts of installed capacity would be built over the next three decades. Figure 55 shows the forecasted amount of energy growth by SMRs and the cumulative number of emissions that could be avoided using SMRs instead of fossil fuels. [153]

[152] Small Modular Reactor (SMR) Global Tracker. (n.d.). *World Nuclear Association*. https://world-nuclear.org/information-library/current-and-future-generation/small-modular-reactor-smr-global-tracker
[153] Small Modular Reactors. (2021). *Nuclear Energy Agency.* Retrieved October 21, 2024, from https://www.oecd-nea.org/upload/docs/application/pdf/2021-10/small_modular_reactors_cop26_flyer.pdf

Figure 55: Forecasted Small Modular Reactor Generation Growth and Emissions Avoidance[154]



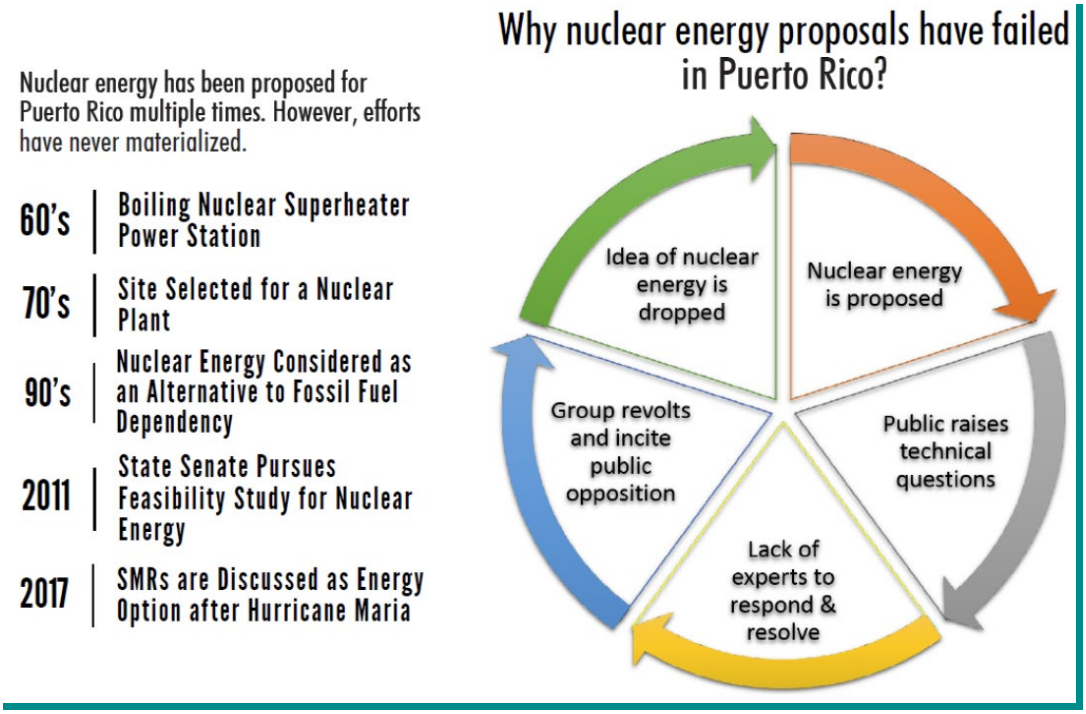
22.4 Small Modular Reactors in Puerto Rico

The Nuclear Alternative Project is a group of Puerto Rican engineers currently studying the potential of an SMR in Puerto Rico. They developed an economic study called Advanced Small Nuclear in Puerto Rico. This report encompasses a wide array of aspects surrounding Puerto Rico's economy and energy sector. Key findings include national energy demand, small modular reactors energy demand, energy supply, and financial and economic sufficiency. Figure 56 shows the track of nuclear procurement in Puerto Rico through the years.[155]

[154] See: https://oecd-nea.org/jcms/203800_Media/smr-installed-capacity-and-cumulative-01?details=true

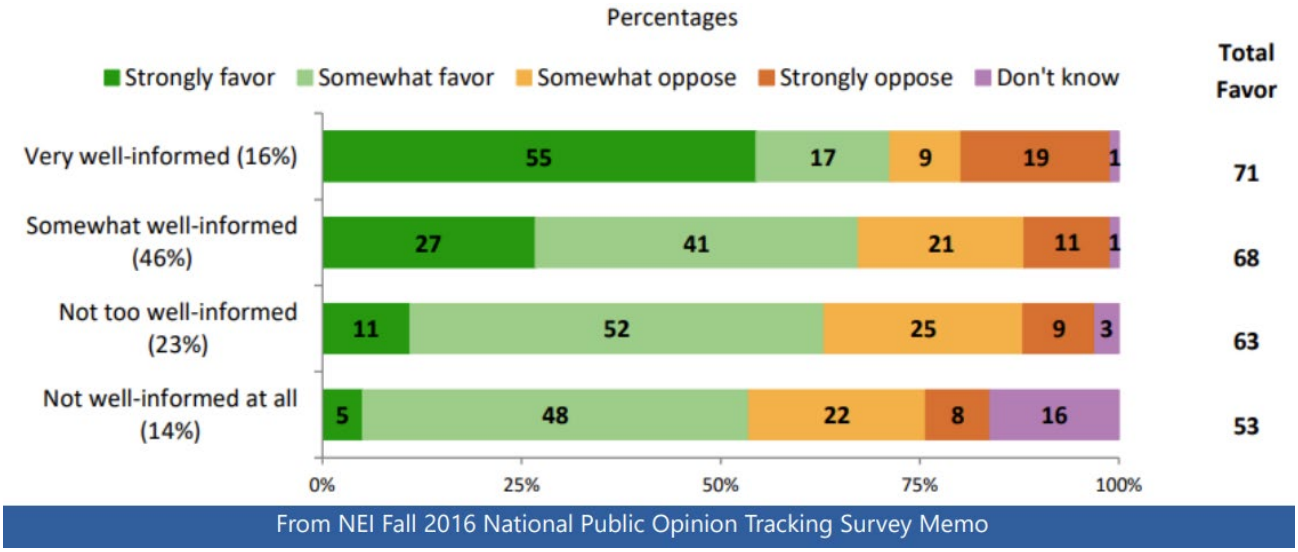
[155] Martínez Colón, R. (2022, May). *Preliminary Feasibility Study for Small Modular Reactors and Microreactors in Puerto Rico* [PowerPoint slides]. Instituto de Ingenieros Civiles. https://iic.ciapr.org/files/2022/05/CIAPR-MEGAVIERNES-CIVIL-PRESENTATION_final.pdf

Figure 56: Nuclear Energy Proposals in Puerto Rico[156]



The graph in Figure 57 illustrates Puerto Ricans' understanding of nuclear energy, as derived from a recent survey. The data indicates that a deeper understanding of nuclear energy is crucial to fostering support for its potential application in Puerto Rico. The study highlights education's critical role in shaping attitudes toward nuclear energy and its potential future in Puerto Rico.

Figure 57: Survey Results About Nuclear Energy Knowledge in Puerto Rico[157]



[156] See: https://iic.ciapr.org/files/2022/05/CIAPR-MEGAVIERNES-CIVIL-PRESENTATION_final.pdf
[157] See: https://iic.ciapr.org/files/2022/05/CIAPR-MEGAVIERNES-CIVIL-PRESENTATION_final.pdf

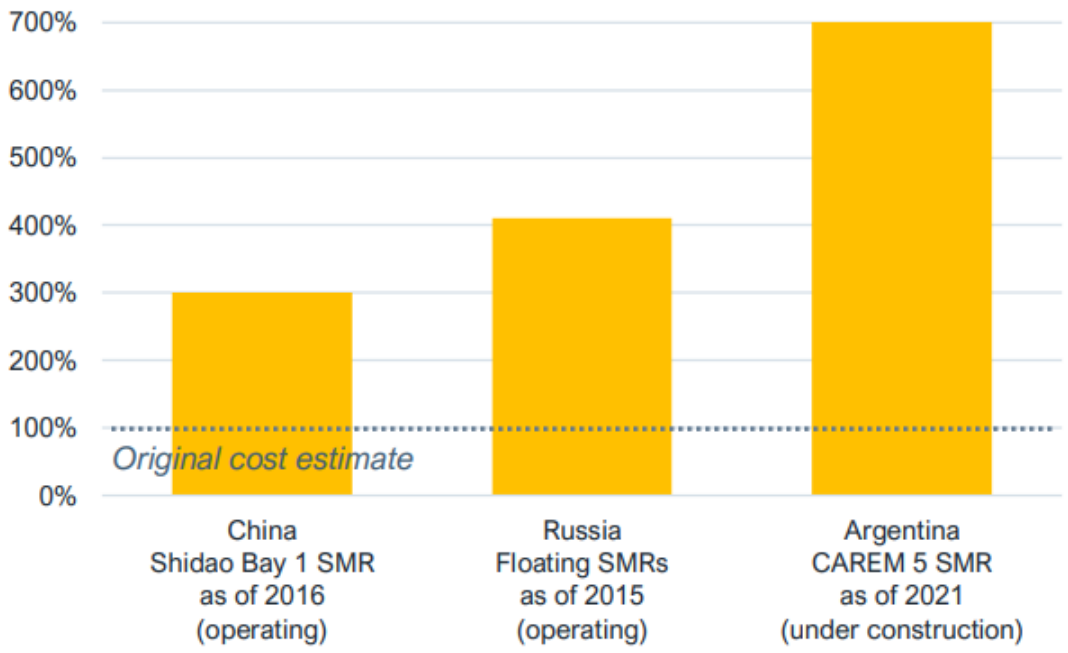
22.5 Costs

Although existing nuclear technology plants have relatively low and stable operating costs, the upfront capital investment costs can be considerable. The difference between traditional large nuclear power plants and SMR is that SMR can be split into modules, and each module is prefabricated and can be shipped to the site for assembly. The compact integral design allows each reactor module to be shipped by rail, truck, or barge, with a reduced capex compared to large nuclear plants.

According to Sargent & Lundy's analytical studies, which consider multiple phases and expenditures associated with SMR, the capital expenditures for these reactors are estimated at $8,935 per kW (based on an example of six 80 MW modules, totaling a 480 MW facility). The estimated fixed O&M costs are $122 per kW-year, while variable O&M costs are projected to be $3.19 per MWh.[158]A preliminary study of SMRs in Puerto Rico highlights that the development of an SMR on the Island would have an LCOE between $98 per MWh and $108 per MWh. [159]

One of the identified initial benefits of an SMR, compared to large nuclear plants, was the potential for cost reduction due to shorter construction time. However, the experience with the initial SMRs that have been built or are currently under construction shows that their costs have been significantly higher than initially forecasted.[160]

Figure 58: Cost Escalation Experience by Small Modular Reactors[161]



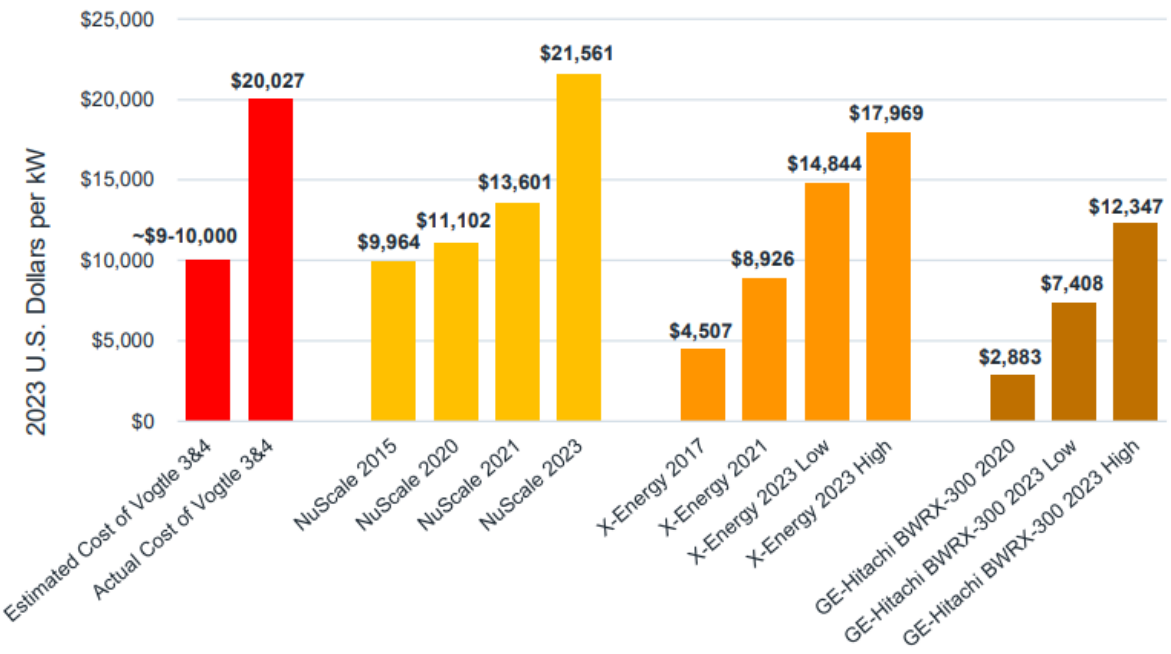
[158] Sargent & Lundy. (2024). Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies. *U.S. Energy Information Administration*. https://www.eia.gov/analysis/studies/powerplants/capitalcost/
[159] HOME | Nuclear Alternative. (n.d.). *Nuclear Alternative*. https://www.nuclearalternativeproject.org/
[160] Schlissel, D. & Wamsted, D. (2024). Small Modular Reactors: Still too expensive, too slow and too risky. *Institute for Energy Economics and Financial Analysis*. https://ieefa.org/resources/small-modular-reactors-still-too-expensive-too-slow-and-too-risky
[161] See: https://understand-energy.stanford.edu/news/understand-small-modular-reactors

The takeaway is that the projected costs significantly understated the actual construction expenditures. According to the latest available information, actual costs for Russian SMRs have increased by more than 400% over initial estimates.[12] Since the estimate is from 2015, it is likely that the final costs were even higher, as the two units did not enter commercial service until 2019. Likewise, reports indicate that the cost for China's Shidao Bay 1 SMR, a 150 MW high-temperature gas-cooled reactor, was three times the initial cost projections. The example from Argentina is even more extreme: Projected costs for the *Central Argentina de Elementos Modulares* 25 MW research reactor, designed to serve as a prototype for 100 MW models, have risen by 600% since the project commenced in 2013. According to the World Nuclear Association, the plant will not begin operation until 2027, making further cost increases a real possibility.

Similar significant cost increases have occurred at proposed projects in the U.S. The Institute for Energy Economics and Financial Analysis has previously documented the problems at NuScale. Costs for the company's SMR more than doubled from 2015 to 2023, rising from $9,964 per kW to $21,561 per kW. This sharp increase led to the cancellation of the company's signature project: a planned six-reactor, 462 MW facility to be built in Idaho in cooperation with the Utah Associated Municipal Power Systems.

NuScale's problems are not unique. U.S. SMR developers have consistently sought to shield their construction cost estimates, but information about two other prominent projects shows that the estimated costs for these projects also have skyrocketed, as shown in Figure 59.[162]

Figure 59: Projected Cost Increases for Proposed Small Modular Reactors in the U.S.[163]



Despite the relative lack of detailed cost data (i.e., fixed and variable costs), constructing a new nuclear plant is demonstrably a capital-intensive venture. The magnitude of the capital costs is much greater

[162] Schlissel, D. & Wamsted, D. (2024). Small Modular Reactors: Still too expensive, too slow and too risky. *Institute for Energy Economics and Financial Analysis*. https://ieefa.org/resources/small-modular-reactors-still-too-expensive-too-slow-and-too-risky

[163] See: https://nuclear-news.net/2024/06/01/1-a-small-modular-nuclear-reactors-get-a-reality-check-in-new-report/

(based on cost per installed MW) than most alternative technology options that are available at present, such as thermal or renewable power generation projects. [164]

Reactor designers have traditionally scaled reactors to larger sizes to take advantage of the economies of scale. In other words, because the fixed costs associated with a nuclear reactor grow very slowly as the size of the reactor increases, it makes sense to increase the reactor's output to reduce the cost per unit of electricity produced as much as possible. To counterbalance the impact of diseconomies of scale, the business case of SMRs relies on economies of series production, which depend on design simplification, standardization, and modularization.

Several specific drivers have been identified:

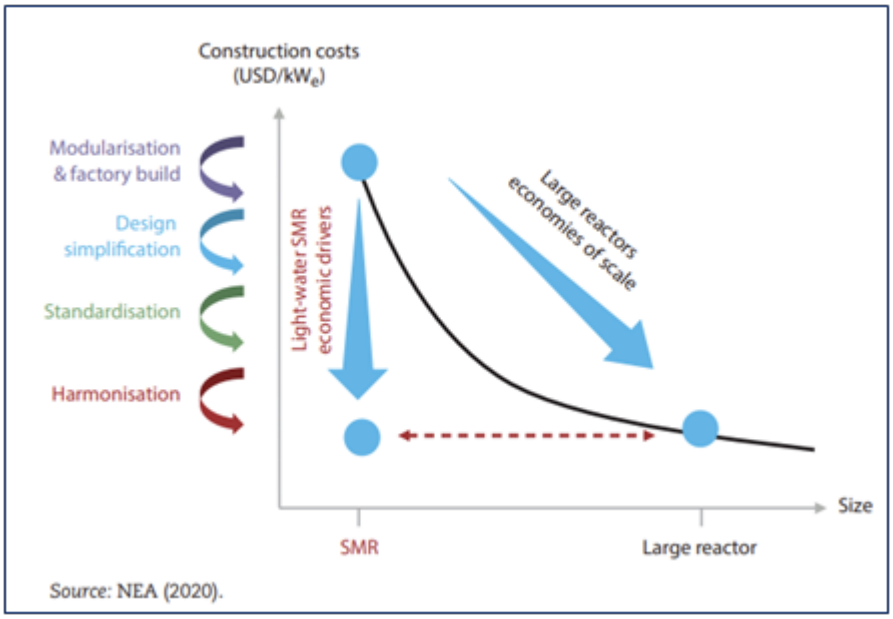
- **Simplification:** Passive mechanism improvements and greater design integration would reduce the number of components and result in savings in containment buildings.
- **Standardization:** SMRs' lower power output reduces the need to adapt to local site conditions, raising the level of design standardization compared with large reactors.
- **Modularization**: Smaller SMR size means transporting their modules easier than transporting large reactors. In fact, the degree of modularization increases considerably for power outputs of less than 500 MW. This trend could be improved with more aggressive modularization techniques tailored to each country's logistical constraints and transport standards. It is estimated that 60-80% of factory fabrication levels are possible for SMRs (with power outputs below 300 MW).
- **Harmonization:** Access to a global market is necessary to foster series-production economies, but this is possible only through regulatory and industrial harmonization.

It is important to mention that key cost drivers for large Generation III nuclear reactors will impact SMR construction costs. However, some specific drivers will carry more weight. This is particularly true for the series effect and simplification, standardization, modularization, and harmonization. The economic benefits would be significant if manufacturers could produce SMRs serially, similar to commercial aircraft. However, a sufficiently large market for a single design is necessary, highlighting the need for a global market. Figure 60 shows how these drivers could reduce the construction costs of SMRs. [165]

[164] International Atomic Energy Agency. (2017). Managing the Financial Risk Associated with the Financing of New Nuclear Power Plant Projects. *IAEA Nuclear Energy*, Series No. NG-T-4.6, IAEA, Vienna. Managing the Financial Risk Associated with the Financing of New Nuclear Power Plant Projects | IAEA

[165] NEA. (2020). Uranium 2020: Resources, Production and Demand. OECD Publishing, Paris Nuclear Energy Agency (NEA) - Uranium 2020: Resources, Production and Demand

Figure 60: Small Modular Reactor Economic Drivers that Compensate for Diseconomies of Scale[166]



22.6 Supply-Chain

The supply chain will play a crucial role in the competitiveness of SMRs. Due to the decline in nuclear construction during the 1980s and 1990s, the nuclear industry's capabilities have diminished. While recent projects have helped rebuild global supply chains, further efforts are needed. Strategic partnerships for key components are essential to share risks and accelerate SMRs deployment. As more SMR modules are delivered, the supply chain may consolidate to achieve economies of scale, similar to the aircraft industry. However, this depends on market dynamics and competitive trends. Future supply chain strategies may focus on efficiency gains through greater integration. Harmonizing codes and standards can promote localization, increase the supplier pool, and enhance the supply chain competitiveness, thereby reducing costs. Commercial, off-the-shelf solutions can also benefit the supply chain.[167]

While SMRs are an emerging technology, several identified risks and challenges may affect deployment and operation. One such challenge is the evolving regulatory environment surrounding SMRs, with uncertainty regarding future regulations and standards. This uncertainty can create ambiguity and reduce confidence among financiers and supply chain stakeholders. Changes in regulations or delays in approvals can negatively affect project schedules and costs. A second challenge is that the ongoing development and refinement of SMR technology may present unforeseen technical issues that could impact costs, safety, and performance. Finally, supply chain disruptions pose a risk due to the SMR supply chain's global nature, making it vulnerable to disruptions caused by geopolitical tensions, trade disputes, or natural disasters.[168]

[166] See: https://oecd-nea.org/jcms/166915_Media/smr-key-economic-drivers-to-compensate-for-diseconomies-of-scale?details=true
[167] Vaya Soler, A. & Berthélemy, M. (2021). Small Modular Reactors: Challenges and Opportunities. *Nuclear Energy Agency*. https://www.oecd-nea.org/jcms/pl_57979/small-modular-reactors-challenges-and-opportunities?details=true
[168] SMR Supply Chain. (n.d.). *Small Modular Reactors*. https://small-modular-reactors.org/smr-supply-chain/

On the other hand, SMRs may require adjustments or new developments for the fuel cycle. Some SMR vendors propose using high-assay, low-enriched uranium (HALEU), which has 5% and 19% enrichment levels. The impact of using HALEU on the global nuclear fuel supply chain and the entire fuel cycle requires further assessment. For countries pursuing a closed nuclear fuel cycle, the ability to use mixed oxide fuel could be crucial for specific SMR designs.

The fuel cycle and supply chain are important considerations for SMR deployment. Kazakhstan, Canada, France, and the United States are the world's leading uranium mining and exporting nations. Significant uranium resources have been discovered in Australia and Namibia. Regarding fuel processing, Russia is the largest supplier of low-enriched uranium, a feedstock for most reactors operating today, followed by Urenco (a consortium composed of Germany, the Netherlands, and the UK), France, China, and the United States. While most water-cooled reactors utilize low-enriched uranium fuel, many advanced reactors are designed to utilize HALEU fuel. Russia and China are the only nations that process and commercially sell HALEU fuel. In 2023, the United States authorized Centrus Energy Corp to begin producing HALEU at its American Centrifuge Plant in Ohio. This facility can produce 900 kilograms of HALEU annually and plans to increase capacity to 6,000 kilograms. Ensuring access to this fuel is essential for the success of Generation IV designs that depend on HALEU fuel.[169]

22.7 Construction and Development

Due to their assembly-line production, SMRs offer the potential for cost reductions and shorter construction times. While the first SMRs are already operational in Russia and China, widespread adoption will require technological and regulatory advancements. This includes developing fuel supply chains and standardizing international licensing processes.

Although SMRs are primarily based on existing nuclear fission technology, the nuclear industry cannot immediately connect them to the grid in large numbers. A 20-year market forecast from an IDTechEx report, based on government policies, SMR designer goals, and data-based benchmarking, will serve as an establishment phase for SMRs in the next decade. Early demonstration reactors will be built to prove commercial feasibility and achieve operational excellence. However, the decades ahead are expected to grow significantly as SMRs are deployed globally from 2024 to 2043.

SMRs often have simpler designs than large reactors, using natural convection for coolant circulation instead of turbopumps, enhancing passive safety. Modularization and prefabricated building elements contribute to lower costs and faster construction. For example, GE-Hitachi's BWRX-300 SMR has an estimated build time of 2-3 years, compared to the average eight-year construction period for large reactors.[170] Table 52 compares the construction time between a large nuclear reactor and an SMR, according to NREL.[171]

[169] Gao B., Kuznetsova K., Ma Z. & Miller K. (2024). Nuclear Small Modular Reactors (SMRs): Key Considerations for Deployment. *International Energy Forum*, (May). https://www.ief.org/_resources/files/events/nuclear-small-modular-reactors-smrs-key-considerations-for-deployment/smr-report.pdf

[170] Dale, S. (2023). How long until small modular reactors make an impact on energy grids? *IDTechEx*, (June 30). https://www.idtechex.com/en/research-article/how-long-until-small-modular-reactors-make-an-impact-on-energy grids/29549#:~:text=Modularization%20and%20the%20use%20of,8%20years% 20for%20large%20reactors

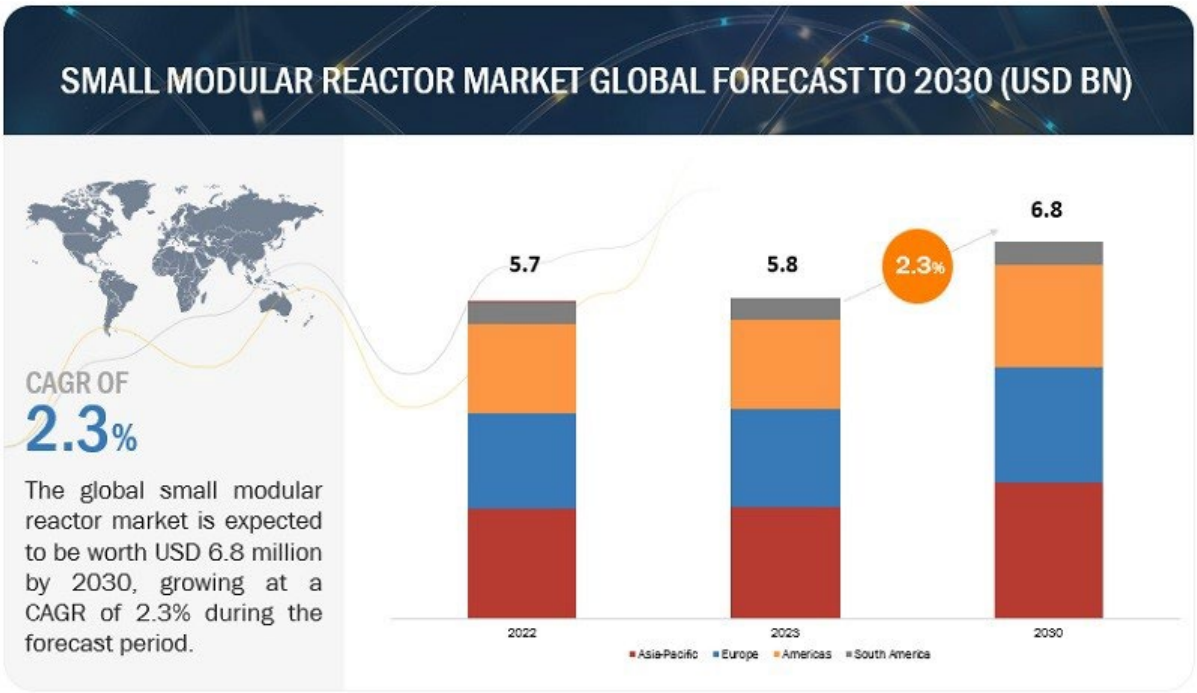
[171] Nuclear | Electricity | 2024 | ATB | NREL. (n.d.). https://atb.nrel.gov/electricity/2024/nuclear

Table 52: Large Nuclear Reactor versus Small Modular Reactor Construction Forecasted Duration Comparison

	Large Reactor	SMR
Power Output	1,000 MW	300 MW
Construction Time (optimistic / expected / conservative)	60 / 82 / 125 months	43 / 55 / 71 months

Market factors will be key to assessing the economic viability of SMR development. As shown in Figure 61, the projected value of SMRs is expected to increase by 2030. Mass production, similar to commercial aircraft, could significantly reduce costs. However, this will require a large market for a single design, emphasizing the need for a global market and suggesting that only a few proposed designs may achieve widespread adoption. Global market support will also depend on regulatory harmonization and reduced design diversity. SMRs introduce untested innovations, which may pose additional technological risks. Successful operation of early SMRs may mitigate these risks and attract more potential customers. The supply chain must be prepared to support SMR market growth, ensuring timely factory-fabrication capabilities, HALEU fuel production, and necessary skills and research and development infrastructure. Additionally, public engagement challenges may arise since many SMRs aim to minimize evacuation zones and locate near population centers. [172]

Figure 61: Small Modular Reactors Market Global Forecast Until 2030[173]

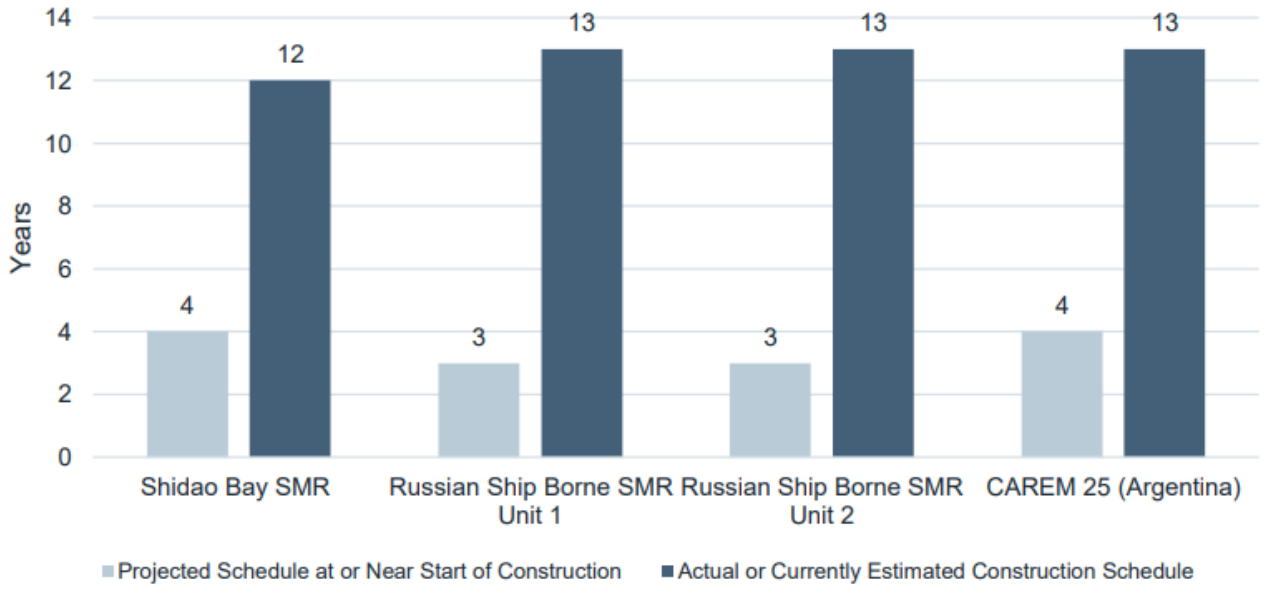


[172] Organization for Economic Co-operation and Development Nuclear Energy Agency (OECD/NEA). (2021). Small modular reactors: Challenges and opportunities [NEA No. 7560]. https://www.oecd-nea.org/jcms/pl_57979/small-modular-reactors-challenges-and-opportunities?details=true

[173] See: https://www.marketsandmarketsblog.com/small-modular-reactor-market-to-witness-huge-growth-2023-2030.html

Like the cost estimates, forecasted SMR construction timelines are proving inaccurate, with significant cost overruns primarily caused by construction delays affecting most SMR projects. In Russia, China, and Argentina, long construction delays have been the norm, not the exception. As shown in Figure 62, none of these SMRs has come close to meeting their projected three- to four-year construction schedules.[174]

Figure 62: Projected Versus Actual SMR Construction Schedules[175]



22.8 Operation

In most power plants, a turbine must spin to generate electricity. Coal, natural gas, oil, and nuclear energy rely on fuel to generate steam, which drives the turbine. Unlike traditional power plants that burn fossil fuels, nuclear plants do not burn any material to create steam, producing no carbon emissions or air pollutants.

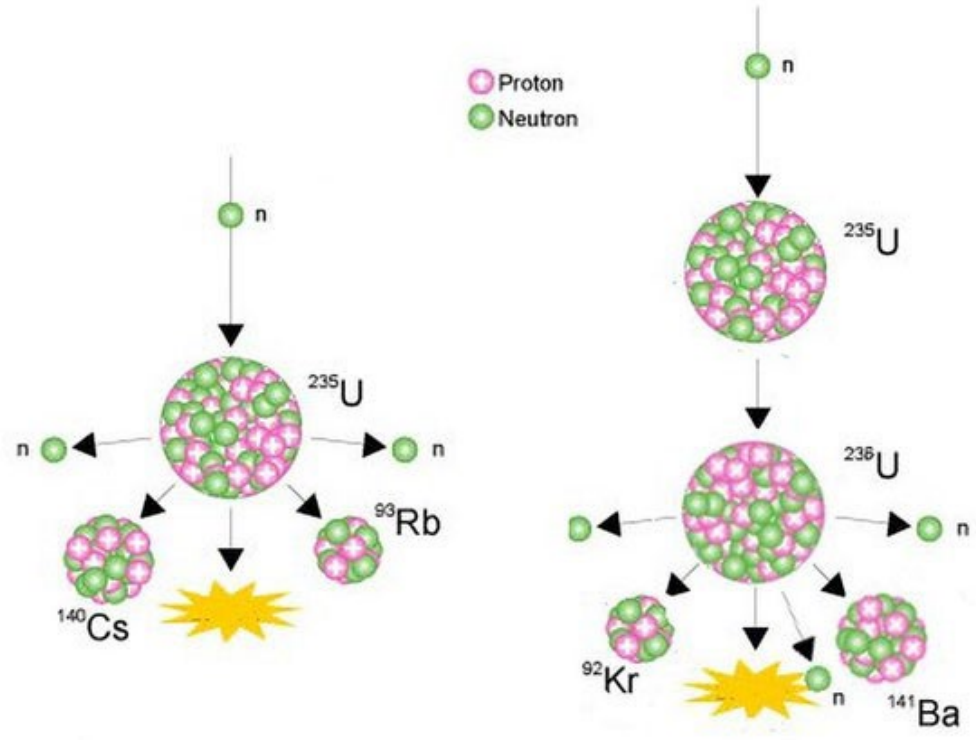
Figure 63 shows how a typical nuclear reactor splits atoms through fission. In fission, a particle, known as a neutron, is fired at an atom, causing it to split into two smaller atoms and release additional neutrons. The process can continue as some released neutrons strike other atoms, causing them to fission and release more neutrons. This is called a chain reaction. The fissioning of atoms in the chain reaction also releases much energy as heat. A circulating fluid, typically water, removes the generated heat from the reactor. This heat can then be used to generate steam, which drives turbines for electricity production. To ensure the nuclear reaction takes place at the right speed, reactors have systems that accelerate, slow, or shut down the nuclear reaction and the heat it produces. This is usually done with control rods, typically made of neutron-absorbing materials like silver and boron.[176]

[174] Schlissel, D. & Wamsted, D. (2024). Small Modular Reactors: Still too expensive, too slow and too risky. *Institute for Energy Economics and Financial Analysis*. https://ieefa.org/resources/small-modular-reactors-still-too-expensive-too-slow-and-too-risky

[175] Schlissel, D. & Wamsted, D. (2024). Small Modular Reactors: Still too expensive, too slow and too risky. *Institute for Energy Economics and Financial Analysis.* https://ieefa.org/resources/small-modular-reactors-still-too-expensive-too-slow-and-too-risky

[176] World Nuclear Association. (n.d.). How Does a Nuclear Reactor Work? https://world-nuclear.org/nuclear-essentials/how-does-a-nuclear-reactor-work

Figure 63: Examples of Nuclear Fission of Uranium-235[177]



SMRs are a scaled-down version of a typical large nuclear reactor, capable of generating between 20 MW and 300 MW of electric power. Their black-start capability allows them to start up a de-energized grid without receiving power from the grid and supply resilient power in the face of natural disasters.[178]

The mechanical systems of an SMR are similar to those found in advanced nuclear power plants. Each reactor module consists of a nuclear core and a steam generator housed within a reactor vessel, which is enclosed within a containment vessel in a vertical orientation. The nuclear core is at the module's base, with the steam generator in the upper half. Feedwater enters the vessel, and steam exits through the top towards the turbine. The entire containment vessel is submerged in a water-filled pool, providing cooling and passive protection in the event of a power loss. All reactor modules are housed within the same water-filled pool inside a typical reactor building. Each SMR module uses a pressurized water reactor design to achieve a high level of safety and reduce the number of components required.[179]

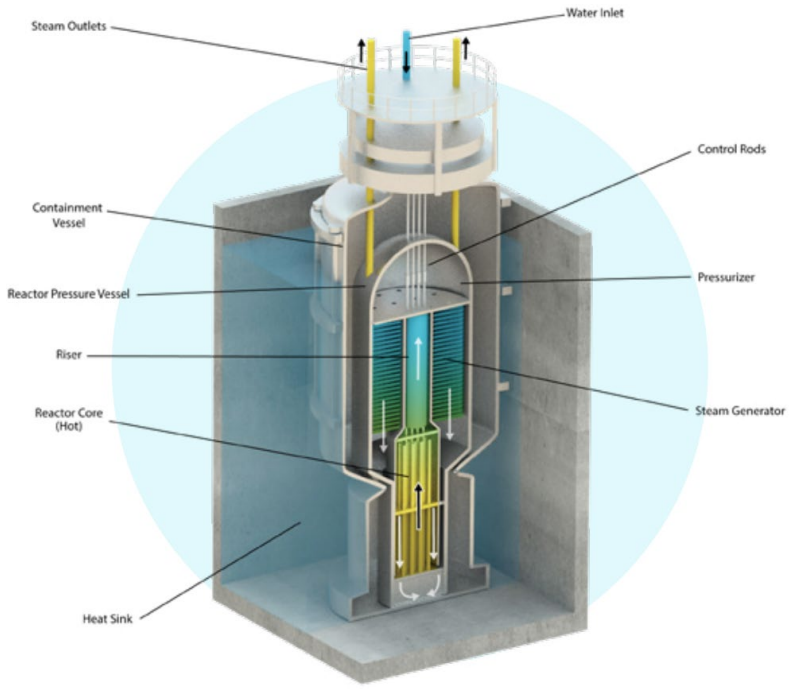
Each module has a dedicated balance-of-plant (BOP) system for power generation. Steam from the reactor module is pumped through a steam turbine connected to a generator for electrical generation. Each BOP system is fully independent and contains a steam turbine and all necessary pumps, tanks, heat exchangers, electrical equipment, and controls for operation. This allows for the independent operation of each reactor module. The independent operation of each reactor module provides greater

[177] See: https://nnr.co.za/how-does-a-nuclear-reactor-work/
[178] Office of Nuclear Energy. The ultimate Fast Facts guide to nuclear energy. (2024). *U.S. Department of Energy*, (February 14). https://www.energy.gov/ne/articles/ultimate-fast-facts-guide-nuclear-energy
[179] Sargent & Lundy. (2024). Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies. *Energy Information Administration*, (January 10). https://www.eia.gov/analysis/studies/powerplants/capitalcost/

efficiencies at lower operating loads when dispatched capacity is reduced. Additionally, the modular design of the reactors allows for refueling and maintenance of the individual reactors without requiring an outage of the entire facility. The pool housed within the reactor building includes an extra reactor bay. This extra bay allows for removing individual reactors for maintenance without impacting the remaining reactors.

While specific dispatchability numbers for SMRs can vary depending on the design and operational parameters, several studies and industry reports have highlighted their potential for rapid response and flexibility. For example, NuScale has projected a high-capacity factor of 95% for its SMRs. This means they aim for the reactors to be operational and generate electricity for 95% of the year. Also, they are designed to be highly dispatchable, meaning they can quickly adjust their power output to meet changing electricity demands. This flexibility is crucial for integrating renewable energy sources and ensuring grid stability. While specific minimum stable power levels can vary between different SMR designs, they are generally expected to operate at lower power levels than traditional nuclear power plants. [180]

Figure 64: Small Modular Reactor Components[181]



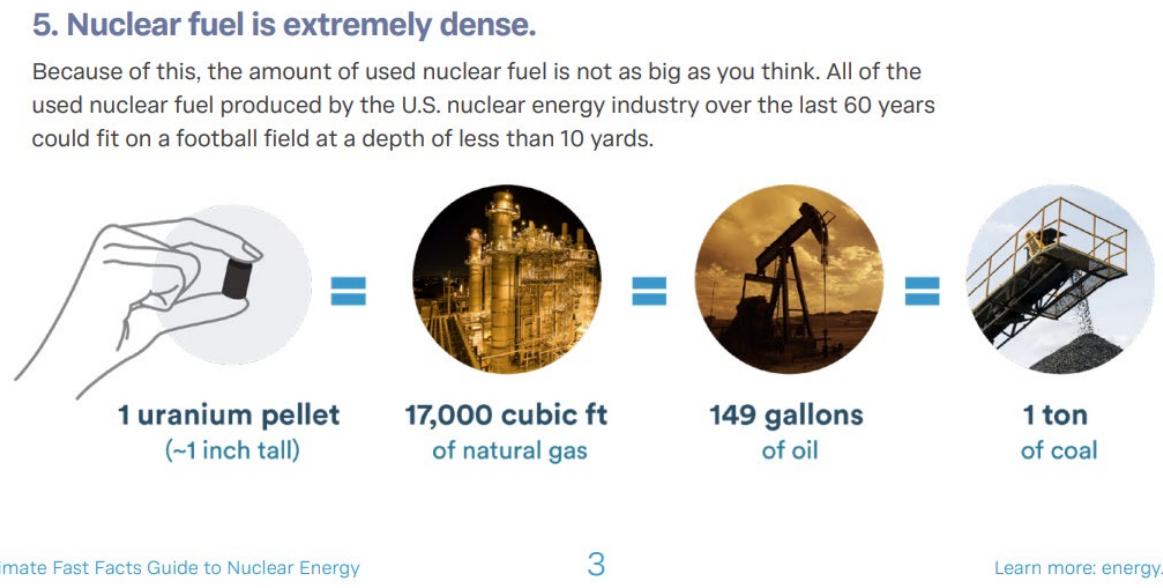
Different fuel materials can be used to fuel a reactor, but most commonly, uranium is used. Uranium is abundant and can be found worldwide, including in the oceans. Other fuels, such as plutonium and thorium, can also be used. Most of today's reactors contain several hundred fuel assemblies, each having thousands of small pellets of uranium fuel. A single pellet contains as much energy as there is in one ton of coal, 149 gallons of oil, and 17,000 cubic feet of natural gas. For example, a 1,000 MW

[180] Romania, U. M. (2021). Repurposing coal power plant sites with a NuScale small modular reactor power plant (Fact sheet) - *U.S. Embassy in Romania*, (November 4). https://ro.usembassy.gov/repurposing-coal-power-plant-sites-with-a-nuscale-small-modular-reactor-power-plant-fact-sheet/#:~:text=NuScale's%20flexible%20operations%2C%20load%20following,of%20grid%20integration%20with%20renewables

[181] See: https://www.energy.gov/sites/default/files/2024-02/ne-2023fastfactsguide-print-021424.pdf

reactor typically requires about 27 tons of fresh fuel yearly. In contrast, a similar coal power station would need more than two-and-a-half million tons of coal to produce as much electricity. Furthermore, only one ton of natural uranium can produce 44 GWh of electricity. To reach this amount of electricity from fossil fuels, it would need to burn over 20,000 tons of coal or 8.5 million cubic meters of natural gas. Figure 65 compares a single uranium pellet with other known fuel technologies.[182]

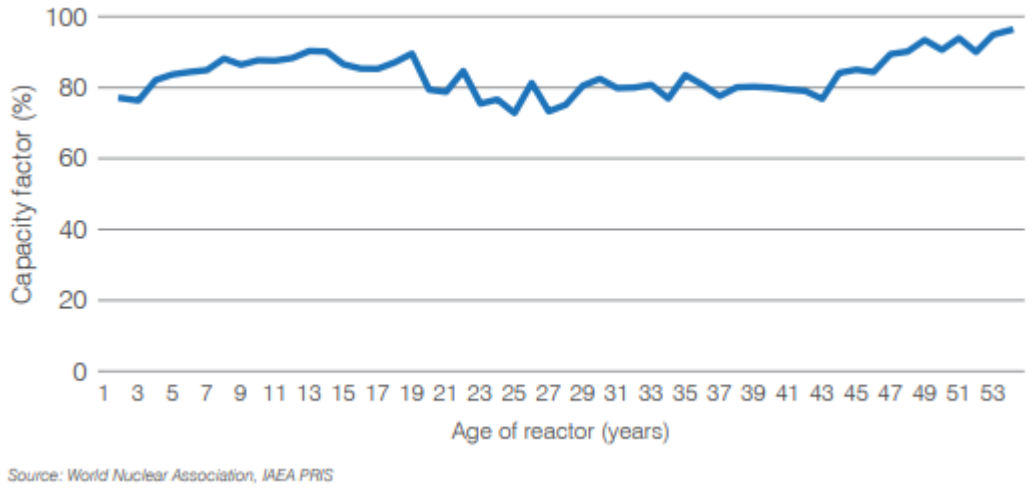
Figure 65: Small Modular Reactors Versus Other Existing Thermal Units Fuel Comparison[183]



The graph shown in Figure 66 illustrates there is no overall age-related decline in nuclear reactor performance. However, there is some variation, with lower average capacity factors for those reactors between 25 and 35 years of operation and higher-than-average capacity factors for those exceeding 45 years.[184]

[182] World Nuclear Association. (n.d.). Nuclear Fuel Cycle Overview. https://world-nuclear.org/information-library/nuclear-fuel-cycle/introduction/nuclear-fuel-cycle-overview
[183] See: https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_64392.pdf
[184] World Nuclear Association. (2023) World Nuclear Performance Report 2023. nuclear performance-report-2023-final.pdf

Figure 66: Capacity Factor by Age of Reactor (2018-2022)[185]



Source: World Nuclear Association, IAEA PRIS

Table 53 summarizes some of the benefits of SMRs and how they can be adapted to many forms of use in an electrical system.

Table 53: Small Modular Reactor Resiliency and Reliability Benefits[186]

Small Modular Reactor Resiliency and Reliability Benefits	
Carbon-free baseload power	SMRs provide carbon-free baseload power.
Enhanced security	SMRs may be safer than conventional reactors since they will be built below ground, thus making them better protected from human and natural risks. Transportation of fuel may be minimized since the reactors can be fueled when manufactured in a factory.
Modularity	Limited on-site construction is required, as work is concentrated in the manufacturing stage.
Scalability	SMRs have responsive, adaptable site capacity and can provide power for various applications. In developing countries lacking the transmission infrastructure to support a large nuclear plant, SMRs offer utilities a way to keep baseload power on the grid. Utilities could use SMRs as on-site replacements for aging fossil fuel plants, taking advantage of existing transmission infrastructure.
Flexibility	SMR design allows output to vary over days, hours, or minutes. This can enable SMRs to adjust their production in response to changes in electricity output from intermittent renewable generation.
Small land requirements	The small size of SMRs may allow them to be sited in places where a large baseload plant is not feasible. It is estimated that SMRs require only 1% of the land area for similar generation by other technologies.

[185] See: https://world-nuclear.org/our-association/publications/world-nuclear-performance-report/global-nuclear-industry-performance-2023

[186] Scully Capital Services. (2017). Small Modular Reactors: Adding to Resilience at Federal Facilities. *U.S. Department of Energy.* https://www.energy.gov/sites/default/files/2018/01/f47/Small%20Modular%20Reactors%20-%20Adding%20to%20Resilience%20at%20Federal%20Facilities%20.pdf

Small Modular Reactor Resiliency and Reliability Benefits	
Reduced fuel risk	SMRs can help diversify a generation portfolio and reduce fuel risk. The price of electricity from SMRs, especially under a long-term contract, should be relatively stable and predictable. Natural gas prices have historically been very volatile, although low in recent years. Higher natural gas prices would significantly increase the price of electricity produced from natural gas.

22.9 Sustainability

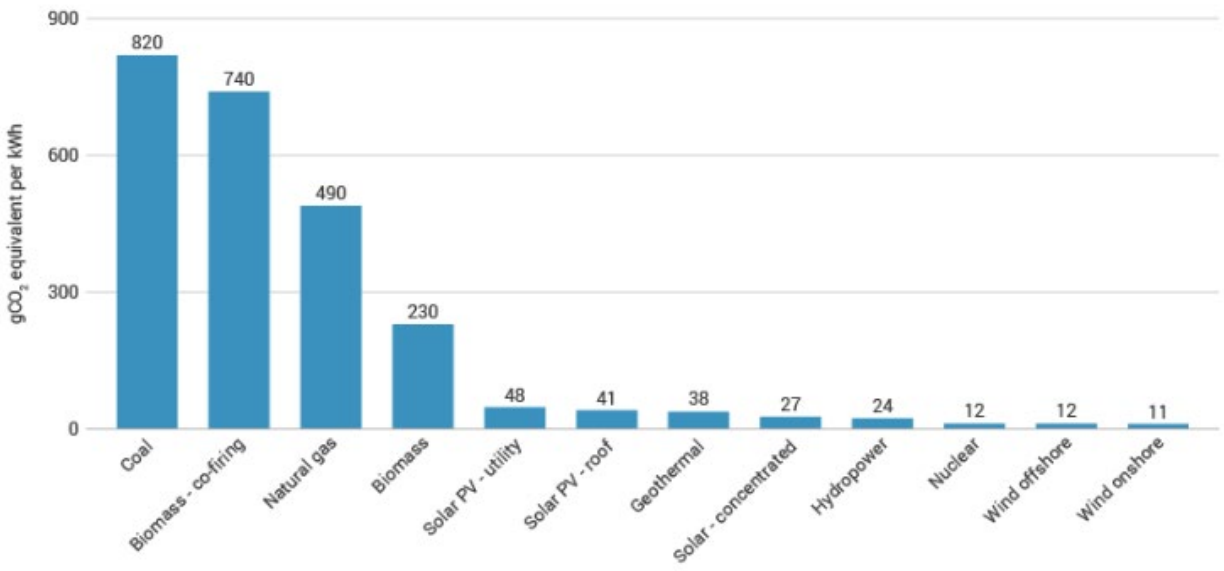
SMRs offer a significant environmental benefit: a low carbon footprint. Nuclear energy, including SMRs, produces far fewer greenhouse gas emissions than fossil fuels, making them attractive for countries aiming to reduce carbon emissions and combat climate change. The modularity and scalability of SMRs allow for a more flexible and efficient deployment of nuclear power, potentially accelerating the transition from fossil fuels. On the other hand, SMRs are designed to be significantly smaller than traditional nuclear power plants, offering a more compact footprint. While the exact footprint can vary depending on the specific SMR design and configuration, they are generally estimated to be about one-third the size of a conventional nuclear power plant. For example, a proposed 920-MW NuScale SMR would have a 35-acre footprint, while a traditional nuclear plant generating the same amount of electricity would require nearly 500 acres.[187]

All electricity generation technologies emit greenhouse gases at some point in their life cycle. In the case of SMRs, emissions will come from construction, decommissioning, and nuclear fuel mining. Research indicates that SMRs' overall lifecycle emissions are significantly lower than those of fossil fuels. On a life cycle basis, nuclear power emits just a few grams of CO_2 equivalent per kWh of electricity produced. While estimates vary, the United Nations (UN) Intergovernmental Panel on Climate Change (IPCC) has provided a median value among peer-reviewed studies of 12g CO_2 equivalent/kWh for nuclear, like wind, and lower than all types of solar. Figure 67 shows the CO_2 emissions per kWh between multiple energy sources.[188]

[187] Advanced small modular reactors. (2024). *Idaho National Laboratory*, (October 31). https://inl.gov/trending-topics/small-modular-reactors/

[188] Carbon Dioxide Emissions from Electricity. (n.d.). *World Nuclear Association*, Updated on Tuesday, September 3, 2024. https://world-nuclear.org/information-library/energy-and-the-environment/carbon-dioxide-emissions-from-electricity

Figure 67: CO_2 Emissions per kWh Comparison Between Multiple Energy Sources[189]



Like traditional nuclear power plants, SMRs generate radioactive waste from nuclear fission. Proper waste management is crucial for protecting human health and the environment, and SMRs hold potential advantages in in this area. Some designs incorporate advanced fuel cycles that reduce or reuse existing nuclear waste. Additionally, their smaller size and modular nature could enable more centralized and efficient waste storage and disposal solutions. Table 54 shows different options for waste management for SMRs that the authors provided in the International Energy Forum report.[190] However, long-term nuclear waste storage remains a concern, and public acceptance is essential for SMR success.

Table 54: Summary of Waste Management Options for Small Modular Reactors

Summary of Waste Management Options for Small Modular Reactors	
Dry cask Stores nuclear waste on site. Currently used to store waste for large nuclear reactors and can be used for SMR waste streams. SMR waste storage requires evaluation of canister spacing and thermal management due to elevated neutron leakage and decay heat levels.	**Geological disposal** Disposal of nuclear waste in a deep underground repository with stable geological formations. Finland is in the construction process of a geological disposal facility, and its operation license application is under review. France, Russia, Sweden, and Switzerland have planned projects with selected sites. Further research and development are required regarding the suitability of SMR waste. SMR waste disposal requires managing decay heat, canister spacing, and thermal considerations, as well as employing extra barriers to prevent long-lived isotopes from escaping into the environment.

[189] See: https://greyhouse.weissratings.com/5-reasons-uranium-is-green-energy-s-best-friend

[190] Gao, B., Kuznetsova, K., Ma, Z., Miller, K. (2024). Nuclear Small Modular Reactors: Key Considerations for Deployment. *International Energy Forum*, (May). https://www.ief.org/resources/files/events/nuclear-small-modular-reactors-smrs-key-considerations-for-deployment/smr-report.pdf

Summary of Waste Management Options for Small Modular Reactors	
Reprocessing facility A facility designed to extract usable materials from SNF for reuse while managing radioactive waste. Currently used in France, Japan, and Russia. SMR waste reprocessing requires evaluating the fuel's heightened chemical reactivity, which could lead to increased reactivity levels during reprocessing.	**Regional waste management program** A reprocessing facility in one country, where the nuclear waste of all countries in the region is reprocessed. Proposed but not currently politically feasible. SMR reprocessing requires evaluation of potential increased reactivity levels.

Land and water use associated with power generation can significantly impact local ecosystems and biodiversity. SMRs, due to their smaller size and compact design, generally require less land and infrastructure than large-scale nuclear power plants, which could help reduce habitat disturbance and land-use conflicts. Furthermore, SMRs can be designed to minimize water consumption by using advanced cooling technologies, such as air or dry cooling. This mainly benefits water-scarce regions, reducing the strain on local water resources and protecting aquatic ecosystems.[191]

Currently, SMRs are designed to have a lifespan comparable to traditional nuclear power plants, typically around 40-60 years. However, advancements in materials science, reactor design, and maintenance techniques could extend this lifespan significantly. With careful planning, optimized refueling schedules, and potential regulatory flexibility, SMRs may even be able to operate for 100 years or more, offering a highly reliable and long-lasting source of electricity.[192]

[191] Small Modular Reactors: Assessing Their Environmental Impact. (n.d.). *Small Modular Reactors*. https://small-modular-reactors.org/smr-environmental-impact/

[192] Fedchenko, V. (2024). Small modular reactors may have climate benefits, but they can also be climate vulnerable. *Stockholm International Peace Research Institute*, (January 26). https://www.sipri.org/commentary/blog/2024/holding-page-vitalys-blog-smrs-and-climate-vulnerability#:~:text=Most%20are%20intended%20to%20produce,approach%20100%20years%20or%20more.

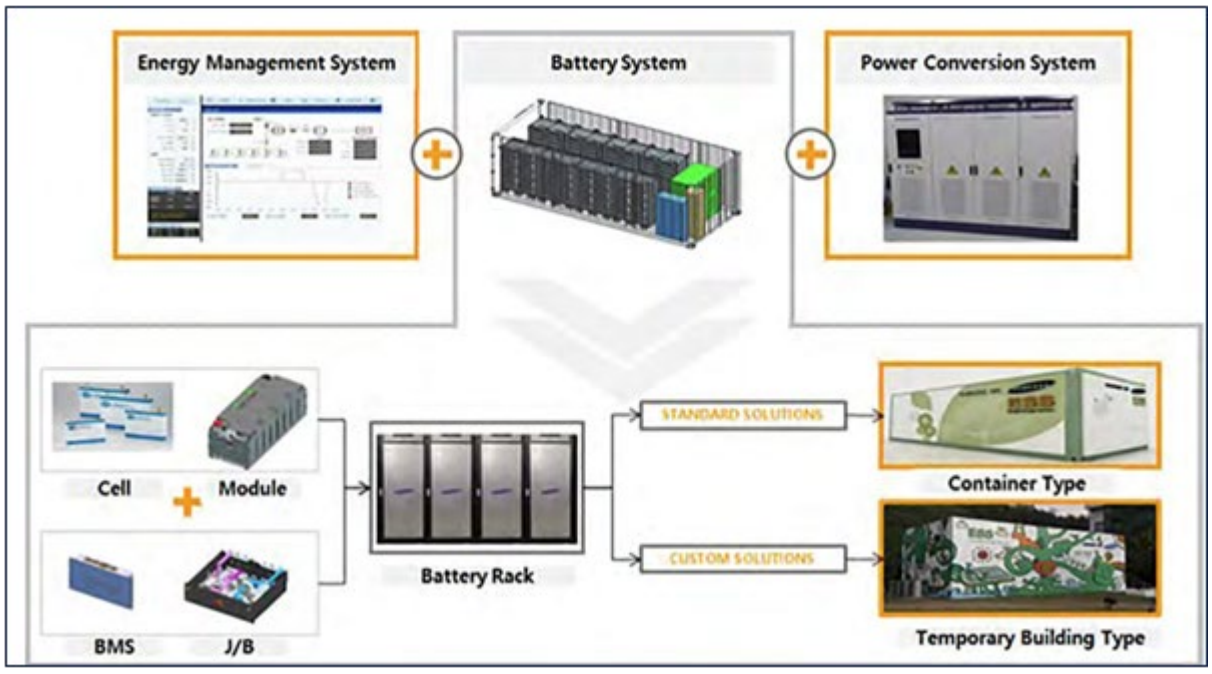
23.0 *New Resource Option:* Non-Lithium Batteries

23.1 Description

Batteries "charge" when they absorb energy using an electrochemical reaction and "discharge" when they deliver the stored energy. The energy stored can come directly from a renewable energy device or the electric grid. Because batteries operate with direct current (DC) while the electric grid operates on alternating current (AC), charging and discharging batteries require power inverters to transform energy from AC to DC when charging or DC to AC when discharging. Batteries also require a battery energy management system to control the charge and discharge of electricity so as not to damage the battery or shorten its operating life. The combination of a battery, power inverter, and battery energy management system is referred to collectively as a battery energy storage system (BESS).

BESS can store surplus energy from intermittent renewable sources, such as solar photovoltaic and wind power, until needed, enabling the integration of more renewable energy into the system.[193] Batteries can also store energy when energy costs are lower and then discharge it during hours of higher energy costs. Figure 68 shows the schematic of a BESS system connected to a grid.[194]

Figure 68: Battery Energy Storage System on the Electrical Grid[195]



[193] Technologies. (n.d.). *European Association for Storage of Energy*. Retrieved on February 27, 2024. https://ease-storage.eu/energy-storage/technologies/
[194] Tumino, P. (2020). The Architecture of Battery Energy Storage Systems. *EE Power*, (September 23). https://eepower.com/technical-articles/the-architecture-of-battery-energy-storage-systems/
[195] See: https://es.dtsolarpower.com/info/the-architecture-of-battery-energy-storage-sys-94587112.html

Currently, the most common type of battery used in the power industry and electric vehicles utilizes a lithium-ion (Li-ion) chemical composition. Researchers are exploring, developing, and testing several non-lithium battery chemistries. Some of the most promising non-lithium BESS chemistries are sodium-ion (Na-ion), magnesium-ion (Mg-ion), and vanadium redox flow, which are discussed further below in this section. These BESS technologies are already working alternatives to lithium batteries, and some are being deployed in early-stage demonstration projects. Battery chemistries differ in key technical characteristics, each with unique advantages and disadvantages.

23.1.1 Sodium-ion Batteries

Sodium-ion (Na-ion) batteries are based on electrochemical charge/discharge reactions between a positive electrode (cathode) composed of sodium-containing layered materials and a negative electrode (anode), typically made of hard carbon compounds. During charging, sodium atoms in the cathode release electrons to the external circuit and become ions, which migrate through the electrolyte toward the anode. They combine with electrons from the external circuit while reacting with the layered anode material. This process is reversed during discharge.[196]

Experts consider Na-ion batteries promising alternatives to Li-ion batteries for the next 5 to 10 years, primarily due to their low levelized cost of storage (LCOS). Recent research has identified potential solutions for grid electricity storage applications using Na-ion batteries. The research aims to reduce LCOS. To achieve this, researchers target a battery system that offers more than 5,000 cycles and a capital expenditure of less than $300 per kWh. [197]

23.1.2 Magnesium-ion Batteries

Magnesium-ion (Mg-ion) batteries are an emerging energy storage technology with several advantages over traditional Li-ion batteries. These batteries consist of an anode, typically made from magnesium metal, a cathode composed of metal-oxide materials, and an electrolyte that facilitates the movement of magnesium ions (Mg^{2+}) between the electrodes. During discharge, magnesium ions move from the anode to the cathode, generating electrical energy, while the process reverses during charging.[198] One key benefit of Mg-ion batteries is their potential for higher energy density due to magnesium's divalent nature. This allows for more energy storage per volume compared to Li-ion batteries.[199]

Recent research developments show promise, including new activation strategies that enable Mg-ion batteries to operate without corrosive additives and the development of aqueous magnesium batteries that utilize water as an electrolyte. These innovations improve safety while achieving competitive energy densities.[200] Developers' ongoing efforts focus on enhancing cathode materials and electrolyte formulations to improve performance metrics. Overall, the outlook for Mg-ion batteries remains positive as researchers continue to address existing challenges. With advancements in materials science, Mg-ion batteries could become a viable alternative for applications such as electric vehicles and large-scale energy storage systems, offering improved safety, relative cost, and environmental benefits.

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[196] Technologies. (n.d.). *European Association for Storage of Energy.* Retrieved on February 27, 2024. https://ease-storage.eu/energy-storage/technologies/

[197] Id.

[198] Sagoff, J. (2023). Q&A: Magnesium-Ion Battery Prospects Get Energized. *Argonne National Laboratory*, (January 23). https://www.aps.anl.gov/APS-Science-Highlight/2023-01-23/magnesium-ion-battery-prospects-get-energized

[199] Id.

[200] Jeon, A-Re, et al. (2023). Reversible magnesium metal cycling in additive-free simple salt electrolytes enabled by spontaneous chemical activation. *ACS Nano*, Vol. 17, Issue 10, (May 8). https://doi.org/10.1021/acsnano.2c08672

23.1.3 Vanadium Redox Flow Batteries

Flow batteries use two liquid electrolytes—one with a positive charge and one with a negative charge—as energy carriers. An ion-selective membrane separates the electrolytes, allowing selected ions to pass through and undergo chemical reactions during charging and discharging. A key advantage of this technology is the complete decoupling of peak power and energy storage capacity. The energy storage capacity can be increased solely by increasing the volume of liquid electrolytes. This feature makes technology a potentially more cost-effective solution for applications requiring medium- or long-duration storage.

The history of flow batteries dates back to the early 1970s when the National Aeronautics and Space Administration began developing this type of battery. The first technology created was iron chromium, which exhibited poor performance characteristics due to capacity degradation at the time. Since then, several other types have been developed, with the vanadium redox battery (VRB) emerging as the most promising. According to the U.S. Department of Energy (DOE) database, as of early 2018, the DOE database reports that approximately 259 MW (around 80%) of the 322 MW of evaluated flow battery storage capacity belongs to VRBs. Most of these projects are in Asian countries such as China and Japan.[201]

Table 55 summarizes some advantages and disadvantages of Na-ion, Mg-ion, and flow batteries.

Table 55: Advantages and Disadvantages of Some Non-Li-Ion Battery Energy Storage Systems

Non-Lithium Battery Type	Advantages	Disadvantages
Sodium-ion	Low LCOS Low carbon emissions	Low cycle life Low energy density
Mg-ion	High energy density Improved safety High raw material abundance Low toxicity materials	Dendrite formation Corrosive electrolytes with magnesium
Vanadium redox	High cycle life (~>12,000) Suitable for storing medium and large amounts of energy.	Low energy density High capital costs

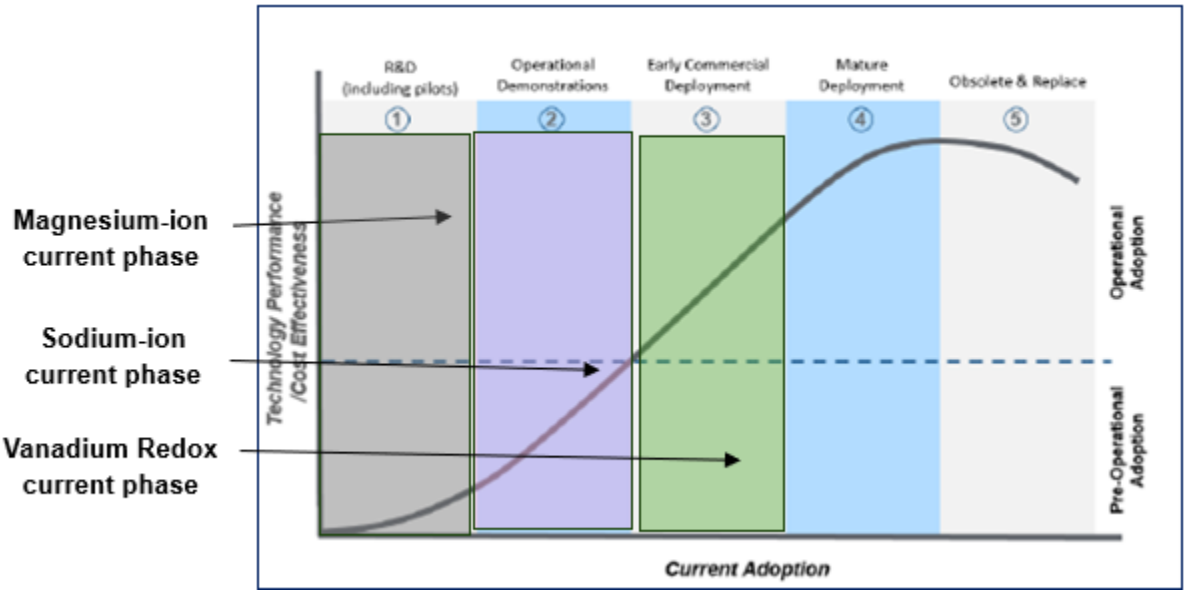
Multiple non-Li-ion battery chemistries are under research and development for grid-scale applications, including metal air, nickel-cadmium, lead-acid, sodium nickel, zinc-bromide, and nickel-hydrogen. Among these, nickel-hydrogen a promising option due to its competitive usable energy output, which is one of the highest among those studied. It is designed for up to three cycles per day with 2—to 12-hour charge/discharge rates, while its competitors typically offer similar rates but with only 1-2 cycles per day.[202]

23.2 Technology Maturity

The non-Li-ion battery chemistries discussed are in various stages of technology maturity. Figure 69describes the rationale behind categorizing them based on their maturity.

[201] Id.
[202] Resources. (n.d.) *EnerVenue, Inc.* https://enervenue.com/resources/

Figure 69: Battery Energy Storage System Technology Adoption Cycle



- Sodium-ion batteries: transitioning to the operational demonstration stage (2nd stage)
- Magnesium-ion batteries: research and development (1st stage)
- Vanadium redox flow batteries: early commercial deployment (3rd stage)

23.2.1 Sodium-ion Batteries

Na-ion batteries are progressing toward operational demonstrations, with significant advancements in manufacturing and project implementation. Recent announcements indicate that Natron Energy is building the first large-scale Na-ion battery factory in the U.S., significantly increasing production capacity.[203] Additionally, the world's most extensive Na-ion battery energy storage system has recently come online in China, demonstrating the practical application of this technology in grid-scale settings.[204] These developments suggest that Na-ion technology is transitioning from research and development to real-world energy storage applications.

Technological advancements and increasing investments in energy storage solutions drive the significant growth of Na-ion batteries' future. According to a report from the DOE in August 2024, while innovation costs for Na-ion batteries remain relatively low, the implementation period for these innovations tends to be longer than other technologies. The report projects that the average levelized cost of Na-ion storage in 2030 will be approximately $0.553 per kWh for a 100-megawatt Na-ion battery

[203] Blois, M. (2024). "Natron Plans First US Sodium-ion Gigafactory." *Chemical & Engineering News*, American Chemical Society, 2024, cen.acs.org/energy/energy-storage-/Natron-plans-first-US-sodium/102/web/2024/08. Accessed 24 Sept. 2024.
[204] Murray, C. (2024). World's largest sodium-ion BESS comes online in China as it seeks to diversify away from lithium. *Energy-Storage News*, (July 4). https://www.energy-storage.news/first-half-world-largest-200mwh-sodium-ion-project-comes-online-china/

system with 10 hours of storage, notably higher than the $0.143 per kWh for an equivalent Li-ion system.[205]

This anticipated cost structure highlights the challenges Na-ion technology must overcome to compete effectively in the energy storage market. However, the DOE's analysis indicates that Na-ion batteries have the potential to address critical needs in long-duration energy storage, making them valuable for applications where energy density is less of a priority.[206] As advancements continue to improve their performance metrics, including energy density and cycle life, Na-ion batteries are becoming increasingly viable for various applications, from grid-scale energy storage to electric vehicles. Market projections suggest that the global Na-ion battery market could grow significantly, reaching around $914.67 million by 2030, with a compound annual growth rate of 16.3% from 2024 to 2030.[207] Rising demand for sustainable energy solutions and favorable government policies promoting clean energy technologies drive this growth.[208] Moreover, industry experts predict that Na-ion batteries could achieve cost parity with Li-ion batteries as early as 2025, driven by advancements in manufacturing processes and economies of scale.[209]

Specific projects utilizing Na-ion technology in Puerto Rico are still emerging. However, the technology's ability to contribute to grid stability makes it a promising candidate for future energy storage solutions on the Island.

23.2.2 Magnesium-ion Batteries

Mg-ion batteries are primarily in the research and development phase. While significant academic interest and preliminary studies have demonstrated their potential advantages over Li-ion batteries, commercial deployment remains limited. The market for Mg-ion technology is still in its early stages, but magnesium's abundance and lower cost than lithium are driving growing interest. Research institutions and companies are exploring ways to overcome technical barriers related to electrolyte compatibility and cathode materials.[210]

As research progresses, advancements in magnesium-ion technology are expected to drive increased adoption, particularly considering sustainability concerns and the need for alternatives to lithium batteries. In 2023, a research team at the University of Hong Kong's Department of Mechanical Engineering published the results of a study they conducted to develop a high-performance, quasi-solid-state magnesium-ion battery, addressing many of the limitations of traditional Li-ion technologies. This innovative design enhances safety and offers competitive energy density, positioning magnesium-ion

[205] U.S. Department of Energy. (2024). Achieving the promise of low-cost long duration energy storage: An overview of 10 R&D pathways from the Long Duration Storage Shot technology strategy assessments, (p.23). https://www.energy.gov/sites/default/files/2024-08/DOE_Long_Duration_Energy_Storage_Report_August_2024.pdf

[206] Id

[207] Grand View Research. (2024). Sodium-ion battery market size, share & trends analysis report by technology (sodium sulfur battery, sodium salt battery, sodium air battery), by end-use (consumer electronics, automotive, industrial, energy storage), by region, and segment forecasts, 2024 - 2030. https://www.grandviewresearch.com/industry-analysis/sodium-ion-battery-market-report

[208] Murray, C. (2024). Sodium-ion push accelerates as China and US announce gigawatt-hour production facilities. *Energy Storage News*, (August 16). https://www.energy-storage.news/sodium-ion-push-accelerates-china-and-us-gigawatt-hour-production-facilities/

[209] Id.

[210] Xu, R., Gao, X., Chen, Y., Peng, C., Zhang, Z., Wang, C., Sun, H., Chen, X., & Cui, L. (2023). Research advances of the electrolytes for rechargeable magnesium-ion batteries. *Science Direct*, Volume 36, Issue 101186, (August). https://www.sciencedirect.com/science/article/abs/pii/S2542529323002225

batteries as viable alternatives in various applications.[211] Moreover, magnesium is significantly more abundant than lithium, which positions it as a promising candidate for addressing supply chain vulnerabilities associated with critical minerals.[212]

Breakthroughs in these areas could significantly improve magnesium-ion batteries' performance and commercial viability, positioning them as a key player in the future of energy storage technologies. While there are no known large-scale projects involving magnesium-ion batteries in Puerto Rico, the technology may become a viable option on the Island as it matures.

23.2.3 Vanadium Redox Flow Batteries

VRFBs are in the early commercial deployment phase. Several projects have been successfully implemented globally, with some installations exceeding 5 MW capacity. Notable deployments in Australia, China, and Europe demonstrate their effectiveness in grid-scale applications. [213]

The VRFB market is experiencing steady growth, driven by an increasing demand for efficient energy storage solutions that support renewable energy integration. Market analysis indicates the global VRFB market was valued at approximately $351.6 million in 2024, with projections showing continued significant expansion.[214] VRFBs' unique characteristics — such as their long lifespan, deep discharge capabilities, and the recyclability of vanadium electrolytes — contribute to their appeal as a sustainable energy storage option.

Despite these advantages, VRFB production costs remain relatively high compared to other battery technologies. Vanadium accounts for a significant portion of these costs, limiting adoption, particularly among smaller enterprises with fewer resources. However, ongoing research and development efforts aim to reduce costs while improving performance metrics.

23.3 Cost

The cost associated with these technologies is discussed in the paragraphs that follow.

23.3.1 Sodium-ion Batteries

Current capital expenditure estimates for Na-ion battery systems indicate an average cost of approximately $87 per kWh in 2024. This pricing positions Na-ion batteries competitively against Li-ion batteries, which average around $89 per kWh. While these costs highlight the potential for Na-ion technology, they also underscore the early stage of deployment and the need for economies of scale to reduce costs further. [215]

Researchers are observing substantial improvements in energy density and efficiency in Na-ion batteries, with a projected increase of approximately 57% by 2024. Experts anticipate that these

[211] Leong, K.W., Pan, W., Yi, X., Luo, S., Zhao, X., Zhang, Y., Wang, Y., Mao, J., Chen, Y., Xuan, J., Wang, H. & Leung, DY.C. (2023). Next-Generation Magnesium-ion Batteries: The Quasi-Solid-State Approach to Multivalent Metal Ion Storage. *Science Advances*, 9(32), (August 9). https://doi.org/10.1126/sciadv.adh1181

[212] Celadon, A. & Sun, H. (2024). Batteries for Electric Vehicles: Technical Advancements, Environmental Challenges, and Market Perspectives. *SusMa*t, vol. 4, no. 5, p. 11, (August 26). https://doi.org/10.1002/sus2.234

[213] Sati, A. (2024). Vanadium redox flow battery market size & industry share: Growth Trends & Forecasts (2023-2030). *Consegic Business Intelligence*. https://www.consegicbusinessintelligence.com/vanadium-redox-flow-battery-market/

[214] Sati, A. (2024). Vanadium redox flow battery market size & industry share: Growth Trends & Forecasts (2023-2030).*Consegic Business Intelligence*. https://www.consegicbusinessintelligence.com/vanadium-redox-flow-battery-market/

[215] Gordon, O. (2024). Exclusive: Sodium batteries to disrupt energy storage market. *Energy Monitor*, (July). www.energymonitor.ai/energy-storage/exclusive-sodium-batteries-to-disrupt-energy-storage-market/?cf-view

advancements will significantly reduce the cost of Na-ion technology, potentially bringing capital costs down to as low as $10 per kWh by 2028. They consider achieving a cost of around $50 per kWh essential for making battery energy storage systems economically viable for grid-scale, long-duration energy storage applications.[216]

Fixed operation and maintenance (O&M) costs for Na-ion batteries average $11 per kW-year, while variable O&M costs are around <$0.03 per kWh.[217] Regarding the LCOS, Na-ion batteries are more expensive than other battery technologies, principally due to their currently low cycle life. Their LCOS ranges from $0.40 per kWh to $0.58 per kWh. However, by 2030, experts anticipate a 54% improvement in the LCOS of Na-ion batteries, with costs potentially decreasing to between $0.23 per kWh and $0.28 per kWh. [218]

23.3.2 Magnesium-ion Batteries

Mg-ion batteries remain in the research phase, and specific capital cost estimates are not widely available. However, the abundant supply of magnesium suggests that these batteries could be produced at a lower cost than Li-ion alternatives once commercialized. Magnesium is significantly more abundant than lithium, which could reduce material costs and create a more sustainable supply chain for battery production.[219]

Due to the simplicity of their systems, Mg-ion batteries are anticipated to have low fixed operation and maintenance costs. The technology's design minimizes complexity, which should lead to lower maintenance requirements over time. As the technology matures, more precise figures regarding capital and O&M costs will become available.[220]

Variable O&M costs will depend on specific applications and usage patterns, but they are expected to be competitive with other battery technologies once commercialized. As research progresses, advancements in materials and battery design will likely enhance the performance and relative cost of magnesium-ion batteries, making them a viable option for large-scale energy storage solutions.

23.3.3 Vanadium Redox Flow Batteries

According to a 2020 grid energy storage cost and performance assessment, estimates for a 1 MW and 10 MW redox flow system indicate that capital costs are approximately $367 per kWh for a 1 MW system and $341 per kWh for a 10 MW system in 2020, with projections suggesting further reductions by 2030.

Regarding LCOS, 2021 calculations show that VRFBs range between $0.17 and $0.28 per kWh for durations between 2 and 10 hours for systems ranging from 10 to 100 MW. The lowest LCOS values occur at approximately 10 hours for all battery systems, showing that 10-hour systems provide the best cost-to-energy output ratio based on current capital costs. At shorter durations, life cycle limitations

[216] Id.
[217] U.S. Department of Energy. (2019). Storage cost and performance characterization report (Final report). https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf
[218] Storage Innovations 2030. (n.d.). *U.S. Department of Energy*. https://www.energy.gov/oe/storage-innovations-2030
[219] Supra on note Celadon.
[220] Supra on note Murray.

require more frequent augmentation or replacement, while at longer durations, the number of cycles per day decreases, which reduces the cumulative discharge over time.[221]

According to a 2030 LCOS estimate, battery storage will decrease by approximately $0.03 to $0.05 per kWh between 2021 and 2030 for lower duration (≤ 8-hour) systems, depending on the technology used. The difference between 2021 and 2030 LCOS values will become more significant for longer durations, with a drop of around $0.08 per kWh.[27]

O&M costs for VRFBs can be higher than those for Li-ion or Na-ion systems due to the need to regularly maintain pumps and fluid management systems. The assessment highlights that fixed O&M costs for battery systems generally range from $6 to $20 per kW-year, with most estimates falling between $7 and $16 per kW-year.

Variable O&M costs can fluctuate depending on usage but generally remain moderate due to VRFBs' long lifespan, which can exceed 10,000 cycles. The report indicates that variable O&M costs reach approximately $0.5125 per MWh, making them competitive with other battery technologies once commercialized.[222]

In summary, each battery technology described above exhibits distinct cost profiles:

Table 56: Non-Lithium Batteries Cost Profile Distinctions

Non-Lithium Battery Type	Cost Profile
Sodium-ion	Show promise with competitive capital costs and potential for further reductions as technology matures.
Magnesium-ion	While still in the research phases, its material abundance could potentially lower costs.
Vanadium redox flow	Though higher in capital costs, it offers long-term benefits that may justify its use in specific applications.

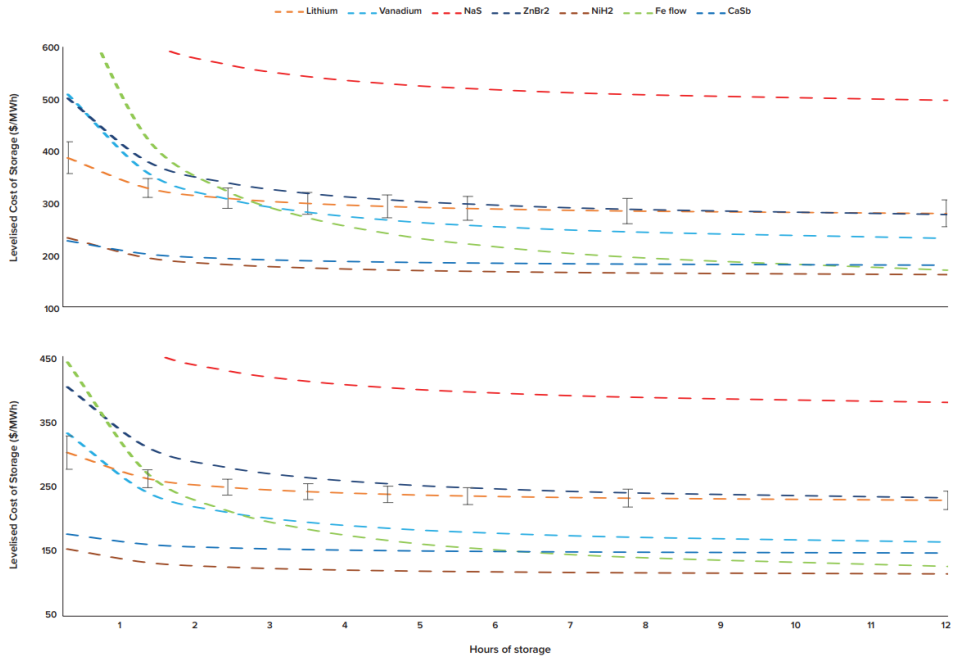
LCOS quantifies the discounted cost per unit of discharged energy, considering factors like system lifetime and charging costs. In this case, Li-ion batteries are compared with a group of non-lithium batteries such as sodium-sulfur, vanadium, zinc-bromide, calcium-antimony, iron flow, and nickel-hydrogen, in addition to the three analyzed in this section. The following figure shows that Li-ion batteries are initially cost-effective for shorter storage durations. Still, other technologies like calcium-antimony and nickel-hydrogen have become more competitive for longer storage durations. Iron flow batteries show promise for high-capacity applications. Operating at two cycles per day, nickel-hydrogen consistently demonstrates the lowest LCOS.[223]

[221] Viswanathan, V., Mongird, K., Franks, R., Li, X. & Sprenkle, V. (2022). 2022 Grid Energy Storage Technology Cost and Performance Assessment. *U.S. Department of Energy.* https://www.energy.gov/eere/analysis/2022-grid-energy-storage-technology-cost-and-performance-assessment

[222] Viswanathan, V., Mongird, K., Franks, R., Li, X. & Sprenkle, V. (2022). 2022 Grid Energy Storage Technology Cost and Performance Assessment. *U.S. Department of Energy.* https://www.energy.gov/eere/analysis/2022-grid-energy-storage-technology-cost-and-performance-assessment

[223] Ara Ake. (2023). Stationary Battery Energy Storage Systems Analysis. *Enervenue*. https://enervenue.com/wp-content/uploads/2023/04/Ara_Ake_Battery_Report_March_2023.pdf

Figure 70: Levelized Cost of Storage of Battery Technologies, Operating at the Top (300 Cycles/Year); at Bottom (600 Cycles/Year)



23.4 Supply-Chain

The supply chain for these technologies is discussed in the paragraphs that follow.

23.4.1 Sodium-ion Batteries

Na-ion batteries are gaining attention as a promising alternative to Li-ion batteries due to their potential for lower costs and greater resource availability. However, technology faces several supply chain constraints and risks that could affect its development and commercialization.

Current energy densities for Na-ion batteries range from 100 Wh/kg to 160 Wh/kg, which is below those of Li-ion technologies.[224] The goal is to achieve energy densities comparable to or exceeding those of current Li-ion systems, which typically range from 150 Wh/kg to over 250 Wh/kg, depending on the specific chemistry used. Major players in the market, such as Contemporary Amperex Technology Co., Limited (CATL), Build Your Dreams (BYD), and Hi-Na Battery Technology Co., Ltd (Hi-Na), have made strides in developing Na-ion technologies. However, practical availability remains limited, and it is projected that original equipment manufacturers may only be able to purchase Na-ion cells by late 2024.

Sodium is abundant and widely available compared to lithium. The global sodium supply is not subject to the same geopolitical risks as lithium, which is concentrated in a few countries like Australia and Chile. This abundance makes Na-ion batteries potentially less vulnerable to supply chain disruptions.

[224] Murray, C. (2023). Northvolt and Altris develop “breakthrough” 160 Wh/kg sodium-ion battery for energy storage. *Energy-Storage News*, (November 21). www.energy-storage.news/northvolt-and-altris-develop-breakthrough-160-wh-kg-sodium-ion-battery-for-energy-storage/.

As mentioned earlier, despite the abundance of sodium, the current capital costs of Na-ion batteries remain a significant barrier to entry. The average cost for Na-ion cells in 2024 is approximately $87 per kWh, marginally cheaper than Li-ion cells, which are around $89/kWh. [225]

Establishing manufacturing capabilities for Na-ion batteries represents specific challenges like those faced by Li-ion technologies. demand for machinery capable of producing Na-ion cells is increasing as companies seek to set up production lines. This transition requires substantial investment in infrastructure and technology development.

The supply chain for electrolytes and separators used in Na-ion batteries is gradually maturing, with production expected to begin in North Carolina by the end of 2024. However, scaling up production capabilities will require significant investment and development efforts.[226]

23.4.2 Magnesium-ion

Magnesium-ion battery technology is emerging as a potential alternative to Li-ion batteries, primarily due to magnesium's abundance and safety advantages.[227] However, several supply chain constraints and risks hinder its development and commercialization.

Mg-ion batteries are still mainly in the research phase, with limited commercial production. Current estimates suggest that while magnesium's theoretical energy density is about 2205 mAh/g, it is significantly lower than lithium's 3862 mAh/g. Magnesium offers a higher volumetric energy density of approximately 3833 mAh/mL compared to lithium's 2046 mAh/mL, making it attractive for specific applications.[228]

Currently, no large-scale manufacturing facilities are dedicated to Mg-ion battery production. Most advancements remain confined to laboratory settings, with significant technical challenges yet to be addressed, such as developing adequate electrolytes and cathodes that operate efficiently without dendrite formation during charging.

For instance, recent research indicates that while magnesium metal can theoretically provide high energy densities, practical issues such as electrolyte compatibility and the slow kinetics of magnesium cycling have limited its application. The Coulombic efficiency of early prototypes was less than 10%, although recent advancements have improved this to over 99.5% in controlled laboratory conditions.[229]

Magnesium is the seventh most abundant element in the Earth's crust, theoretically ensuring a stable supply.[230] However, the processing capabilities for high-purity magnesium suitable for battery applications have not yet been fully developed. Current production primarily focuses on lightweight alloys for automotive applications rather than battery-grade materials.[231]

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[225] Supra at note 8.
[226] Samora, S. (2024). Natron Energy to build $1.4B sodium-ion battery plant in North Carolina. *Utility Dive*, (August 27). www.utilitydive.com/news/natron-energy-1-4-b-sodium-ion-battery-factory-kingsboro-north-carolina/725211/
[227] Ponrouch, A., Bitenc, J., Dominko, R., Lindahl, N., Johansson, P., & Palacin, M. R. (2019). Multivalent rechargeable batteries. *Energy Storage Materials*, 20, 253–262.
[228] Guo, W., Hanaor, D. a. H., Kober, D., Wang, J., Bekheet, M. F., & Gurlo, A. (2022). Rechargeable Magnesium Ion Batteries Based on Nanostructured Tungsten Disulfide Cathodes. *Batteries*, 8(9), 116. https://doi.org/10.3390/batteries8090116
[228] Supra on note Celadon.
[229] Supra on note Celadon
[230] LePan, N. (2021). Visualizing the abundance of elements in the Earth's crust. *Elements by Visual Capitalist*, (December 6). https://elements.visualcapitalist.com/elements-in-the-earths-crust-abundance/
[231] Supra on note 3.

Despite the global abundance of magnesium, geopolitical tensions in key producing regions could affect availability. According to recent estimates, China dominates the magnesium market, producing around 85% of the global supply. Any trade disputes or sanctions could significantly impact global supply chains.[232]

While Mg-ion batteries present promising advantages over traditional Li-ion technologies due to their safety and potential cost benefits from raw material abundance, significant supply chain constraints exist. These challenges include low production volumes and technological readiness levels, alongside risks related to raw material accessibility influenced by policy changes and geopolitical factors. Addressing these challenges through targeted investment in technology development and infrastructure will be essential for unlocking the full potential of Mg-ion batteries in the energy storage market.

23.4.3 Vanadium Redox Flow Batteries

Vanadium redox flow batteries are emerging as a promising technology for large-scale energy storage, particularly in renewable energy applications. However, several supply chain constraints and risks could affect their development and deployment.

Vanadium-ions have specific energy ratings of approximately 15-25 Wh/kg and energy densities ranging from 20-33 Wh/L, which are lower than Li-ion batteries but suitable for stationary applications.[233] Compared to more established systems like Li-ion and lead-acid batteries, the technology is still in the early phases of commercialization. As of late 2021, cumulative global deployment was estimated at over 200 MWh, primarily in Japan and China.[234]

VRFBs' lifespan is notable. They are durable for 20 to 30 years and can cycle more than 12,000 times without significant degradation.[235] This longevity makes them particularly attractive for applications requiring reliable long-term energy storage. However, the current production scale is limited, with only a few companies actively manufacturing VRFBs, contributing to higher costs than other battery technologies.

Vanadium is primarily sourced from countries such as China, Russia, South Africa, and Brazil. While vanadium is relatively abundant, its use in various industries means that any increase in demand for vanadium in energy storage could strain existing supply chains. Currently, vanadium's use in energy storage represents only a fraction of its total demand.

23.5 Construction and Development

The construction and development of emerging battery technologies involve a detailed engineering, procurement, and construction (EPC) process timeline. This overview summarizes the key stages for the following technologies: Na-ion, Mg-ion, and VRFBs. Each technology progresses through distinct phases critical for successful commercialization and integration into energy storage systems.

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[232] SMM. (2024). The impact of magnesium prices on the global market. *SMM Information & Technology Company.* https://news.metal.com/newscontent/102722083/The-Impact-of-Magnesium-Prices-on-the-Global-Market

[233] González-González, J. M. & Aguado, J. A. (2023). Vanadium redox flow batteries (VRFB). In *Encyclopedia of electrical and electronic power engineering*. Table 6: Main characteristics of VRFB batteries (Cunha et al., 2015) and Department of Energy. Grid energy storage. (p. 5).

[234] Department of Energy. (2022). Grid energy storage. (p. 34).

[235] Wang, H., Pourmousav, S.A., Soong, W.L., Zhang, X. & Ertugrul, N. (2023). Battery and Energy Management System for Vanadium Redox Flow Battery: A Critical Review and Recommendations. *Journal of Energy Storage*, vol. 58, p. 106384, (February). https://doi.org/10.1016/j.est.2022.106384

23.5.1 Sodium-ion

The development of Na-ion batteries is gaining momentum as a promising alternative to Li-ion batteries, particularly for large-scale energy storage applications. Understanding the timeline for the EPC process and the related development risks is essential for stakeholders involved in this emerging technology.

Fundamental research is underway to optimize cathode and electrolyte materials specific to Na-ion technology. This includes exploring various compositions, such as Sodium Manganese Oxide and Sodium Iron Phosphate for cathodes, while developing suitable electrolytes that ensure efficient ion transport. Recent advancements have demonstrated improvements in energy density and life cycle, with ongoing studies aimed at enhancing performance metrics comparable to those of Li-ion batteries. [236]

Companies like Natron Energy are already moving towards pilot-scale production of Na-ion batteries and plan to supply grid-scale battery products.[237] Securing partnerships with material suppliers is critical to ensuring the consistent availability of raw materials.

Once pilot production demonstrates viability, commercial scale-up of Na-ion batteries will proceed. The Na-ion battery market primarily focuses on stationary energy storage applications, such as grid stabilization and renewable energy integration. Continuous technological improvements will likely occur as market feedback informs future developments.

Development Risks

Developing adequate electrolytes that facilitate efficient ion transfer while minimizing side reactions is a significant challenge. Current research is focused on finding stable and high-conductivity electrolytes that can operate effectively at various temperatures.[238]

Achieving competitive energy density compared to Li-ion batteries remains a technical hurdle. While Na-ion batteries show promise, they must demonstrate reliable performance under real-world conditions.

The battery market is highly competitive, with established technologies like Li-ion dominating current applications. To gain market share, Na-ion batteries must prove their advantages in relative cost and sustainability.

23.5.2 Magnesium-ion Batteries

Mg-ion batteries have garnered attention as a potential alternative to Li-ion technologies, primarily due to magnesium's abundance and lower cost. However, the path to commercialization has been fraught with challenges. Key hurdles include the large ionic radius of Mg-ions, which leads to slower reaction kinetics and issues with electrolyte compatibility.[239]

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[237] Supra note 8.

[238] Che, H., Yang, X., Yu, Y., Pan, C., Wang, H., Deng, Y., Li, L. & Ma, Z. (2021). Engineering optimization approach of nonaqueous electrolyte for sodium-ion battery with long cycle life and safety. *Green Energy & Environment*, 6(2), 212–219, (April). https://doi.org/10.1016/j.gee.2020.04.007

[239] Mohtadi, R., & Mizuno, F. (2014). Magnesium batteries: Current state of the art, issues and future perspectives. *Beilstein Journal of Nanotechnology,* 5(1), 1291–1311, (August 18). https://doi.org/10.3762/bjnano.5.143

Development Risks

One of the most significant challenges facing Mg-ion batteries is the development of adequate electrolytes that facilitate efficient ion transfer without forming insulating layers on the anode surface. Current organic electrolytes often cause passivation issues, which hinder performance.[240]

Despite these challenges, recent advancements indicate a promising future for Mg-ion batteries. With continued research and development efforts focused on optimizing materials and addressing technical barriers, Mg-ion batteries could emerge as a viable option for energy storage solutions in applications such as EVs and grid storage systems. The ability of magnesium-ion batteries to avoid dendrite growth—one of the significant safety concerns associated with Li-ion batteries—further enhances their appeal as a safer alternative.[241]

As research progresses, the development and commercialization of Mg-ion batteries will depend on overcoming key challenges and demonstrating advantages over existing battery technologies.

23.5.3 Vanadium Redox Flow Batteries

VRFBs are increasingly recognized for their potential in large-scale energy storage applications, particularly renewable energy integration. Understanding the timeline for the EPC process, and the associated development risks, is crucial for stakeholders involved in this technology.[242]

Current development is to optimize the chemistry of vanadium electrolytes and improve the performance of VRFB components, such as membranes and pumps. Research efforts aim to enhance energy density, efficiency, and cycle life while addressing issues like electrolyte stability and cost. Recent progress shows promising results in improving the performance metrics of VRFBs, with studies indicating that they can achieve high power densities and long cycle lives.[243]

Companies like Invinity Energy Systems are already deploying pilot projects to validate production methods and gather operational data. [244] Once pilot production demonstrates viability, commercial scale-up of VRFBs will proceed. The VRFBs market primarily focuses on stationary energy storage applications for longer-duration storage. Continuous improvements in technology will likely occur as market feedback informs future developments.

Development Risks

Developing stable vanadium electrolytes that can maintain performance over long periods is a significant challenge. Research is ongoing to enhance the stability of these electrolytes under varying operational conditions, including temperature fluctuations.[245]

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[240] Id.
[241] Id.
[242] Supra note 39.
[243] Id.
[244] Anderson, R. (2024). ENGIE, Equans and Jan de Nul power up Invinity battery. *Invinity*, (March 27). invinity.com/engie-equans-jan-de-nul-vanadium-flow-battery-belgium/
[245] Supra note 47.

Operators must effectively manage VRFBs, which generate heat during operation, to prevent performance degradation. Designers must create thermal management systems that maintain optimal operating conditions.[246]

The vanadium supply is concentrated in only a few countries, primarily South Africa and China. Any disruptions in supply due to geopolitical tensions or market fluctuations could impact the availability of this critical material. Current estimates suggest that vanadium demand for energy storage applications is increasing, yet it still represents a small percentage of total consumption.

The battery market is highly competitive, with established technologies like Li-ion dominating current applications. VRFBs must prove their relative cost, safety, and sustainability advantages to gain market share against competing technologies.

The construction and development timeline for VRFBs shows significant potential but also presents considerable challenges that developers must address. Technical hurdles—such as electrolyte stability, thermal management, securing raw material supply chains, and navigating market competition—are critical factors that will influence the successful commercialization of VRFBs in the coming years. As research advances, stakeholders must remain vigilant about these risks while pursuing opportunities within this evolving energy storage landscape.

23.6 Operation

23.6.1 Sodium-ion Batteries

Na-ion batteries operate similarly to Li-ion batteries, utilizing Na-ions to transfer charge between the anode and cathode. When discharging, sodium ions move from the anode to the cathode through an electrolyte, generating an electric current. During charging, this process reverses.

- **Maintenance Requirements and Frequency**: Due to their solid-state design, Na-ion batteries require minimal maintenance. Regular inspections of connections and monitoring of electrolyte levels are recommended, but overall maintenance needs are lower than those of traditional lead-acid batteries.[247]
- **Reliability**: Na-ion batteries are designed for high reliability, with a cycle life projected to exceed 5,000 cycles in some configurations. Their performance is stable across a wide temperature range, making them suitable for various environmental conditions.[248]
- **Resiliency**: Using abundant materials like sodium contributes to the resiliency of Na-ion batteries. They are less susceptible to supply chain disruptions than Li-ion batteries, as sodium is widely available and inexpensive. Additionally, Na-ion batteries exhibit a low risk of thermal runaway, enhancing their safety profile.

[246] Le, T. X. H., Bechelany, M. & Cretin, M. (2017). Carbon felt based-electrodes for energy and environmental applications: A review. *Science Direct*, 122, 564–591, (October). https://doi.org/10.1016/j.carbon.2017.06.078
[247] A. James Clark School of Engineering. (2023). New Solid-State Sodium Batteries Enable Lower Cost and More Sustainable Energy Storage. *University of Maryland*, (December 19). https://eng.umd.edu/news/story/new-solidstate-sodium-batteries-enable-lower-cost-and-more-sustainable-energy-storage
[248] Kim, C., Kim, I., Kim, H., Sadan, M.K., Yeo, H., Cho, G., Ahn, J., Ahn, J., Ahn, H. (2018). A Self-Healing Sn Anode with an Ultra-Long Cycle Life for Sodium-ion Batteries. *Journal of Materials Chemistry A*, vol. 6, no. 45, 2018, pp. 22809–22818. https://doi.org/10.1039/c8ta09544b

23.6.2 Magnesium-ion Batteries

Mg-ion batteries utilize magnesium ions (Mg2+) to store and release energy. The operation involves magnesium ions moving between the anode and cathode during the charging and discharging cycles.

- **Maintenance Requirements and Frequency**: Like Li-ion batteries, Mg-ion batteries are expected to require low maintenance. Routine checks on battery health and performance metrics are advisable, but specific maintenance protocols are still being developed as the technology matures.
- **Reliability**: This type of technology is still evolving, with research focused on improving cycle life and efficiency. Current projections suggest that Mg-ion batteries could achieve competitive reliability metrics once commercialized, although specific data on cycle life remains limited.
- **Resiliency**: Magnesium's abundance and low cost compared to lithium enhance the resiliency of Mg-ion batteries. However, the technology is still developing, meaning long-term operational data is not yet fully established.[249]

23.6.3 Vanadium Redox Flow Batteries

VRFBs use vanadium ions in different oxidation states to store energy in liquid electrolytes stored in external tanks. Energy is generated by pumping electrolytes through a cell stack, where electrochemical reactions occur.

- **Maintenance Requirements and Frequency**: VRFBs require regular maintenance primarily related to fluid management systems, including checking electrolyte levels and ensuring pumps function correctly. Maintenance frequency may vary, but it typically involves routine checks every few months.
- **Reliability**: VRFBs are known for their high reliability and long cycle life. Their design allows for easy component replacement without significant downtime, contributing to overall system reliability.
- **Resiliency**: VRFBs' modular nature enhances their resiliency; they can be scaled up or down based on energy storage needs without major redesigns. Additionally, vanadium's availability mitigates supply chain risks associated with other battery technologies.[250]

Each battery technology mentioned above has distinct operational characteristics, as seen in Table 57, that influence maintenance requirements, reliability, and resiliency.

Table 57: Non-Lithium Batteries Characteristics Comparison

Non-Lithium Battery Type	Characteristic
Sodium-ion	Offers a reliable and low-maintenance solution with robust performance metrics.
Magnesium-ion	While developing operational protocols, they promise low maintenance due to their expected design similarities with Li-ion technology.

[249] Magnesium-Ion Battery Prospects Get Energized. (2023). *Argonne National Laboratory*, (January 23). https://www.aps.anl.gov/APS-Science-Highlight/2023-01-23/magnesium-ion-battery-prospects-get-energized

[250] Gunjan, P., Chavez, M. & Power, D. (2022). Vanadium Redox Flow Batteries: Identifying Market Opportunities and Enablers. Commissioned by Vanitec. *Guidehouse Insights.* https://vanitec.org/sustainability-items/pdf/Guidehouse%20Insights-Vanitec%20White%20Paper_FINAL.pdf

Non-Lithium Battery Type	Characteristic
Vanadium redox flow	Provides high reliability with modularity that enhances resiliency against supply chain disruptions.

23.7 Sustainability

23.7.1 Sodium-ion Batteries

- **Land Use and Technology Footprint**: Na-ion batteries utilize abundant materials, primarily sodium, which can be sourced from seawater or underground brine deposits. This reduces the environmental footprint associated with raw material extraction compared to Li-ion batteries, which require mining and can lead to habitat destruction and soil contamination.
- **GHG Emissions**: The life cycle assessment of Na-ion batteries indicates that they have a lower carbon footprint than Li-ion batteries. Estimates suggest emissions of approximately 60 to 100 kg CO_2 equivalents per kWh of storage capacity, depending on the production processes and materials used, which is favorable compared to Li-ion alternatives.
- **Water Usage**: The extraction of sodium is generally less water-intensive than lithium extraction processes, which often require significant water resources for evaporation in salt flats.
- **Recycling Potential**: Designers created Na-ion batteries with more straightforward chemistry to facilitate easier recycling. This streamlined design reduces waste and minimizes the environmental impact associated with their disposal. Existing facilities can integrate the recycling process with minimal modifications.[251]

23.7.2 Magnesium-ion Batteries

- **Land Use and Technology Footprint**: Magnesium is abundant in the Earth's crust and can be sourced from seawater or mineral deposits. Compared to lithium and cobalt, this abundance helps mitigate land use issues associated with mining.
- **Greenhouse Gas (GHG) Emissions**: While specific life cycle assessments for magnesium-ion batteries are still developing, initial studies suggest that their manufacturing processes could result in lower GHG emissions compared to Li-ion batteries, due to the lower energy requirements for magnesium extraction and processing.
- **Other Emissions**: The overall emissions profile is still being evaluated as the technology matures, but magnesium's lower toxicity compared to some Li-ion components (like cobalt) is a positive aspect.
- **Water Usage**: The water usage for magnesium extraction is generally lower than that for lithium mining, making it a more sustainable option regarding water resource management.[252]

[251] A. James Clark School of Engineering. (2023). New Solid-State Sodium Batteries Enable Lower Cost and More Sustainable Energy Storage. *University of Maryland*, (December 19). https://eng.umd.edu/news/story/new-solidstate-sodium-batteries-enable-lower-cost-and-more-sustainable-energy-storage

[252] Magnesium-Ion Battery Prospects Get Energized. (2023). *Argonne National Laboratory*, (January 23). https://www.aps.anl.gov/APS-Science-Highlight/2023-01-23/magnesium-ion-battery-prospects-get-energized

23.7.3 Vanadium Redox Flow Batteries

- **Land Use and Technology Footprint**: VRFBs utilize vanadium extracted from mines or recycled materials. The modular design allows for larger installations without significant land disruption compared to traditional battery systems.
- **GHG Emissions**: Vanadium Redox Flow Batteries (VRFBs) have a favorable emissions profile due to their long life cycle (≈20 years) and ability to utilize recycled vanadium electrolyte. Life cycle assessments indicate VRFB systems emit roughly 0.10–0.12 kg CO_2-eq per kWh over their lifetime, and using 50% recycled electrolyte reduces GWP by about 11% compared to systems with only fresh materials.[253]
- **Other Emissions**: Using non-toxic materials in VRFBs reduces overall environmental impact during operation. Additionally, the risk of hazardous emissions during operation is minimal compared to Li-ion systems.
- **Water Usage**: Water usage in VRFB systems is relatively low since they primarily use liquid electrolytes that do not require extensive water resources for cooling or operation. [254]

Each battery technology described above offers distinct sustainability advantages, as seen in Table 58.

Table 58: Sustainability Advantages of Each Analyzed Battery Technology

Non-Lithium Battery Type	Sustainability Advantages
Sodium-ion	It is an environmentally friendly alternative with abundant materials, lower GHG emissions, and easier recycling processes.
Magnesium-ion	It promises sustainability benefits because its materials are abundant, and emissions are potentially lower.
Vanadium redox flow	It provides a sustainable solution with long life cycles and minimal environmental impact due to its recyclable components and minimal/no use of solid metals like lithium, zinc, nickel, etc.

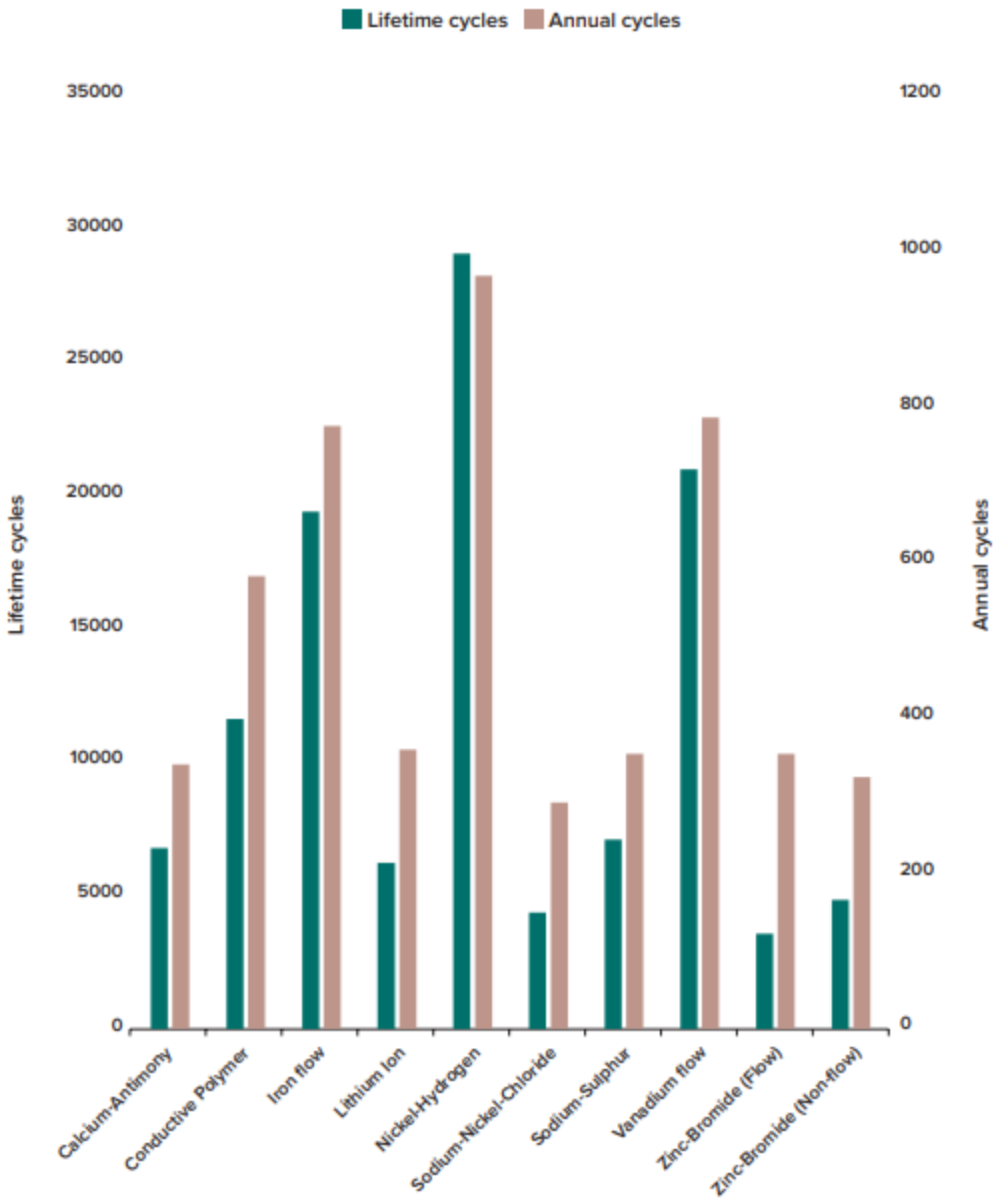
As these technologies advance toward commercialization, ongoing research will continue to refine their sustainability profiles while addressing any emerging environmental concerns.

Figure 71 summarizes the lifetime and annual cycles of several battery technologies. Note that Mg-ion batteries are not listed due to insufficient information and current research.

[253] Da Silva Lima et al., *"Life cycle assessment of lithium-ion batteries and vanadium redox flow batteries–based renewable energy storage systems,"* Sustainable Energy Technologies and Assessments 46 (2021), pp. 5–6

[254] Gunjan, P., Chavez, M. & Power, D. (2022). Vanadium Redox Flow Batteries: Identifying Market Opportunities and Enablers. Commissioned by Vanitec. *Guidehouse Insights*. https://vanitec.org/sustainability-items/pdf/Guidehouse%20Insights-Vanitec%20White%20Paper_FINAL.pdf

Figure 71: Lifetime and Annual Cycles per Battery Technology[255]



23.8 Disposal Methods

23.8.1 Sodium-ion batteries

Their simpler structure allows for more straightforward end-of-life recycling processes, minimizing environmental impacts associated with disposal.

[255] Resources – EnerVenue, Inc. (n.d.). https://enervenue.com/resources/

23.8.2 Magnesium-ion batteries

Although this technology is still under investigation and research, its potential for long life cycles could reduce waste over time. End-of-life strategies will need to be established as commercial production scales up.

23.8.3 Vanadium Redox Flow batteries

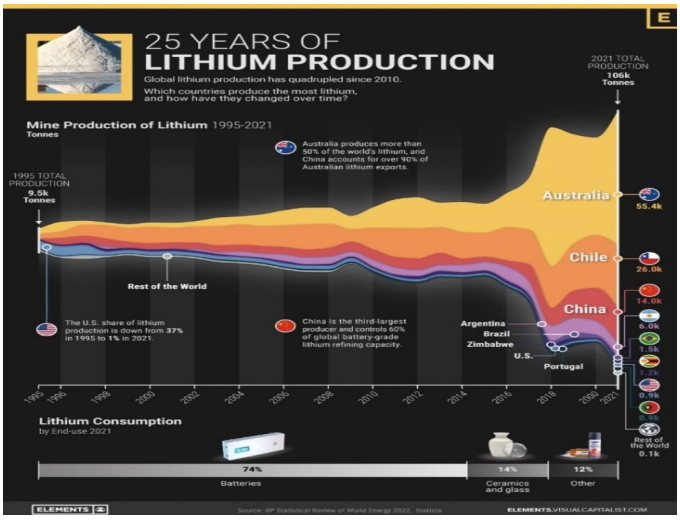
Their modularity allows for easy replacement of components without significant waste generation.

24.0 *New Resource Option: Lithium Batteries*

24.1 Description

Lithium battery technology has emerged as a pivotal energy storage solution, particularly in renewable energy and electric transportation. At its core, lithium-ion batteries (Li-ion batteries) facilitate the movement of lithium ions between an anode and a cathode during charge and discharge cycles, effectively storing electrical energy in a chemical form for later release. Since their commercial introduction in 1991, Li-ion batteries have gained acclaim for their high energy density, long lifespan, and rapid charging capabilities, making them ideal for applications ranging from portable electronics to electric vehicles and renewable energy storage systems.[256] However, this technology is not without its challenges; it faces high costs, safety risks– including thermal runaway incidents that can lead to fires– and environmental concerns related to lithium mining and battery disposal.[257] Various policies, such as renewable portfolio standards and green credits, have been implemented to promote the adoption of lithium batteries. These policies provide financial incentives for energy storage solutions that enhance grid stability and contribute to a sustainable energy future. However, continued reliance on lithium batteries highlights the importance of addressing the noted challenges for their long-term viability and environmental impact.

Figure 72: Lithium Production Over the Last 25 Years[258]



Jurisdictions worldwide, including the European Union, the United States, and China, actively utilize and promote lithium battery technology, especially in the transportation and renewable energy sectors. For

[256] Clean Energy Institute. (n.d.). Lithium-Ion Battery. *University of Washington*. https://www.cei.washington.edu/research/energy-storage/lithium-ion-battery/

[257] Institute for Energy Research. (2023). Environmental Impacts of Lithium-Ion Batteries. *Institute for Energy Research*, (May 11). https://www.instituteforenergyresearch.org/renewable/environmental-impacts-of-lithium-ion-batteries/

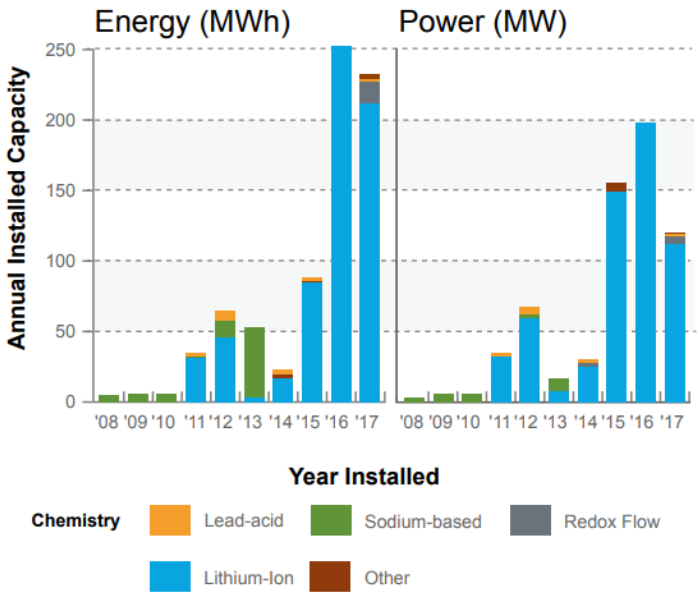
[258] King Lopez, E. (2023). Visualizing 25 Years of Lithium Production. *Litio Argentina*, (March 27). litio.com.ar/visualizing-25-years-of-lithium-production/

example, California's energy storage policies actively support the deployment of lithium batteries to complement solar and wind energy integration.[259]

24.2 Technology Maturity

Lithium-ion batteries (Li-ion batteries) have been increasing over the last few years around the world due to the need for a reliable storage type. As shown in Figure 73, the installed capacity of Li-ion batteries in the United States has increased dramatically from 2011 to 2017 compared to other types of batteries, such as lead-acid batteries. Li-ion batteries are expected to dominate the global market by 2030, as shown in Figure 74.

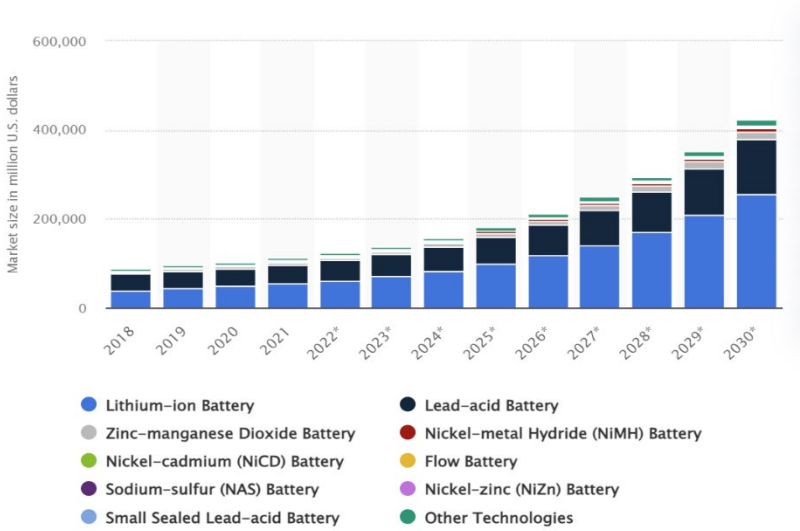
Figure 73: Utility-Scale Battery Storage Capacity in the U.S. Between 2008 and 2017, According to the National Renewable Energy Laboratory[260]



[259] Bhutada, G. (2023). This Chart Shows Which Countries Produce the Most Lithium. *World Economic Forum*, (January 5). https://www.weforum.org/agenda/2023/01/chart-countries-produce-lithium-world/

[260] Daugherty, J. (2024). NREL battery supply chain database maps out the state of North America's manufacturing base. *National Renewable Energy Laboratory*, (May 15). https://www.nrel.gov/news/program/2024/nrel-battery-supply-chain-database-maps-out-the-state-of-north-americas-manufacturing-base.html

Figure 74: Global Battery Market Size Trend Forecast Through 2030 [261]



In general, all types of batteries are expected to increase in demand due to the expanding need for energy storage worldwide. The supply chain for this technology is broad, and different parts of the world support manufacturing this type of technology. Li-ion battery costs are expected to decrease as more utilities implement storage alternatives in their electrical systems. There is potential for improvement in the methods used to obtain raw materials and dispose of this battery type after it reaches the end of its lifespan. All aspects mentioned above position Li-ion batteries as currently in the early part of the fourth stage of the technology adoption cycle (i.e., mature deployment).

24.3 Cost

The costs associated with Li-ion batteries can be categorized into capital costs, fixed operation and maintenance (O&M) costs, and variable O&M costs. As of 2023, the average capital cost for lithium-ion battery packs has significantly decreased to approximately $139 per kWh, marking a 14% reduction from 2022 levels.[262] Projections for 2024 suggest further reductions, with anticipated prices around $133 per kWh and estimates for 2030 indicating potential costs as low as $80 per kWh.[263]

In terms of fixed O&M costs, according to the 2024 Annual Technology Baseline (ATB) from the National Renewable Energy Laboratory (NREL), fixed O&M costs for lithium-ion battery systems are estimated at 2.5% of capital costs kW. This percentage is designed to cover necessary expenses to maintain system performance throughout its operational lifetime, typically around 15 years. Variable O&M costs are associated with end-of-life treatment, including disconnection, battery module removal, and transportation, which can vary widely depending on distance and equipment rental needs.[264]

[261] Dudić, B. (2024). Global Development and Sustainability of Lithium-Ion Batteries in Electric Vehicles. *Advanced Engineering Letters*, 3(2), 83–90, (June 30). https://doi.org/10.46793/adeletters.2024.3.2.5
[262] Catsaros, O. (2023). Lithium-Ion Battery Pack Prices Hit Record Low of $139/kWh. *Bloomberg NEF*, (November 26). about.bnef.com/blog/lithium-ion-battery-pack-prices-hit-record-low-of-139-kwh/
[263] Singh, G. (2024). Lithium Battery Price Trends & Comparisons 2024. *Fenice Energy*, (April 22). blog.feniceenergy.com/lithium-battery-price-trends-comparisons-2024/
[264] Pacific Northwest National Laboratory. (2022). *Grid Energy Storage Technology Cost and Performance Report* (pp. 29–30).

24.4 Levelized Cost of Storage

According to Lazard's latest LCOS analysis, for a utility-scale 100MW, 4-hour standalone battery energy storage system (BESS), the cost ranges from approximately $170 per MWh to $296 per MWh without subsidies. With the full range of tax credit subsidies made available through the Inflation Reduction Act (IRA), this range can fall as low as $124 per MWh for projects that include 'energy community' adders to the investment tax credit rate. The highest calculated LCOS for subsidized projects of that scale was around $226 per MWh.[265]

Li-ion batteries remain competitive compared to other energy storage technologies. Pumped hydro storage typically costs between $100 and $200 per kWh, while compressed air energy storage ranges from $250 to $400 per kWh. Lead-acid batteries may have lower initial costs but offer shorter lifespans and higher maintenance expenses.

Historically, costs for Li-ion batteries have decreased significantly over the past decade, with reductions of over 70% from 2012 to 2022. While some fluctuations are anticipated in the next few years due to material costs and supply chain challenges, the trend favors continued costs. By 2030, costs are expected to decline significantly across all projections, with further reductions anticipated by 2050 resulting from improved efficiency and lower material costs in the evolving energy storage market. [266, 267]

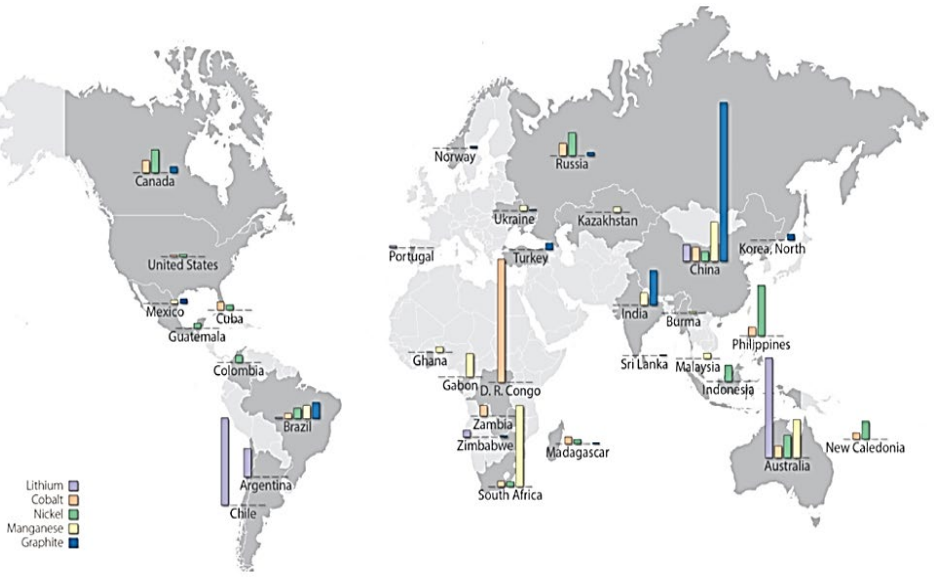
[265] Colthorpe, A. (2024). Lazard: IRA Brings LCOS of 100MW, 4-Hour Standalone BESS down as Low as US$124/MWh. *Energy-Storage.News*, (June 6). www.energy-storage.news/lazard-ira-brings-lcos-of-100mw-4-hour-standalone-bess-down-as-low-as-us124-mwh/

[266] Viswanathan, V., Mongird, K., Franks, R., Li, X. & Sprenkle, V. (2022). 2022 Energy Storage Technology Cost and Performance Assessment. *Pacific Northwest National Laboratory*, (August). https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf

[267] Cole, W. & Karmakar, A. (2023). Cost Projections for Utility-Scale Battery Storage: 2023 Update. *National Renewable Energy Laboratory*, (June). https://www.nrel.gov/docs/fy23osti/85332.pdf

24.5 Supply-Chain

Figure 75: Global Production of the Five Essential Elements Required for the Construction of Lithium Batteries[268]

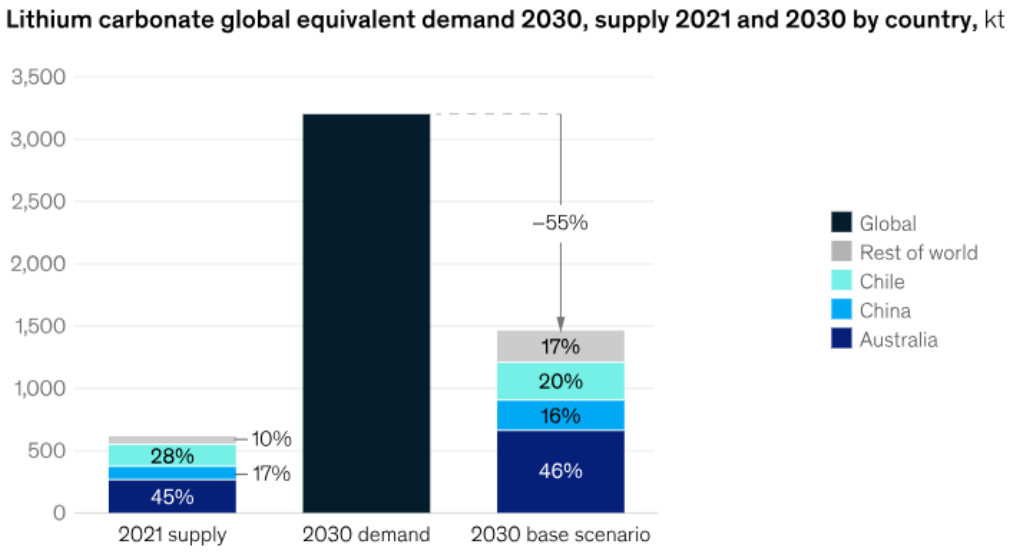


The supply chain for Li-ion batteries will be significantly influenced by the availability of the five essential materials required for their construction: nickel, graphite, lithium, cobalt, and manganese, as seen in Figure 75. The dispersed production of Li-ion battery materials worldwide can create challenges to the supply of these batteries due to geopolitical differences, the increasing demand for this type of battery, and how these materials are obtained. Ethical concerns regarding the mining conditions in the Democratic Republic of Congo, where most of the cobalt is acquired, have raised social concerns about child labor and dangerous working conditions.[269]

[268] Pesaran, A., Putsche, V. & Mann, M. (2024). North American Lithium-Ion Battery Supply Chain Database Development - Phase II. *National Renewable Energy Laboratory*. https://www.nrel.gov/docs/fy23osti/85610.pdf

[269] Anil, M., & Rejikumar, G. (2023). Life Cycle Analysis of Lithium-ion Batteries: An Assessment of Sustainability Impact. In 2023 *International Conference for Advancement in Technology (ICONAT)*, (pp. 1-5). Goa, India.

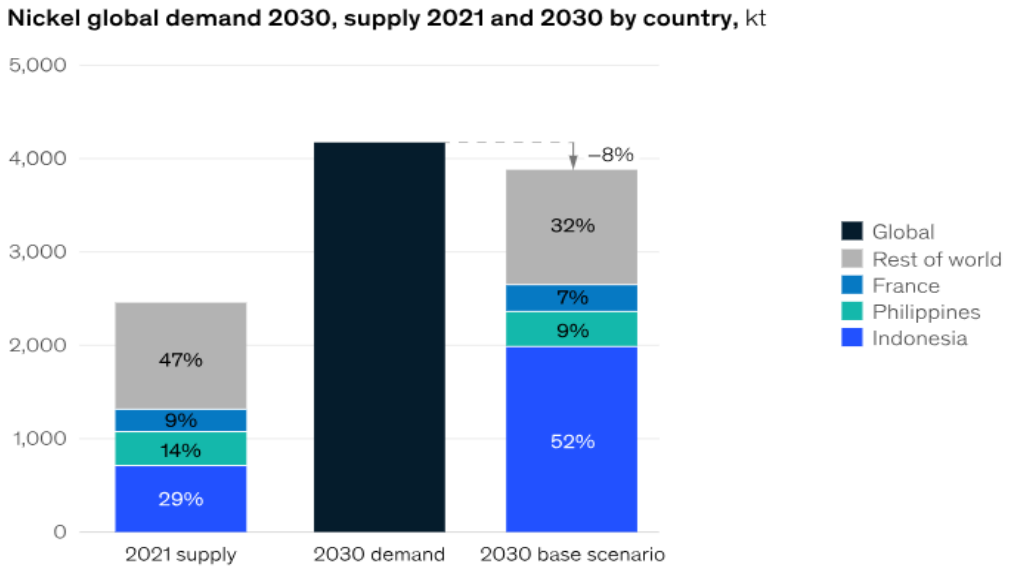
Figure 76: Lithium Supply and Demand Projection for 2030[270]



Lithium carbonate demand is anticipated to increase in the following years. By the year 2030, a 55% deficit of this material is projected due to the technological shift to lithium-heavy batteries and the limited number of countries where high-grade deposits are located. [10]

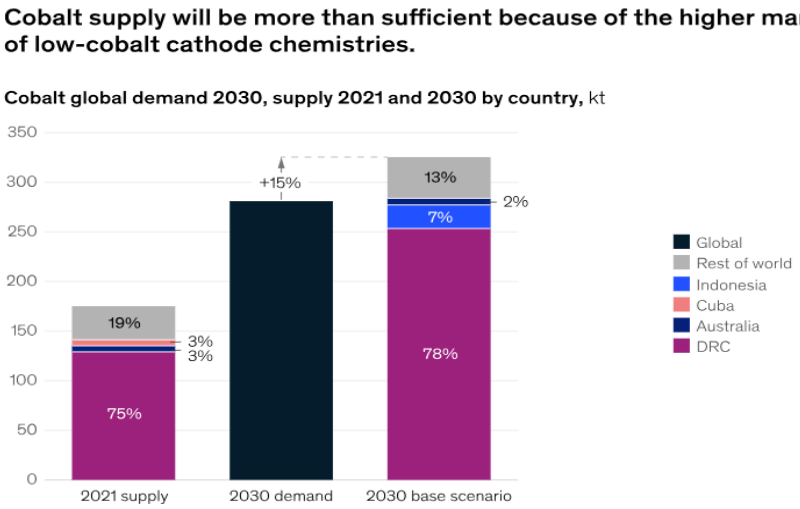
[270] Fleischmann, J., & Schaufuss, P. (2023). Battery 2030: Resilient, sustainable, and circular. *McKinsey & Company*, (January 16). www.mckinsey.com/industries/automotive-and-assembly/our-insights/battery-2030-resilient-sustainable-and-circular#/.

Figure 77: Nickel Supply and Demand Projection for 2030[15]



In the year 2030, a small dip in the supply of nickel is forecasted due to the limited geographic distribution of the mines and the need for the high-purity class 1 of nickel, which is suitable for battery production, rather than the lower purity of class 2.[271]

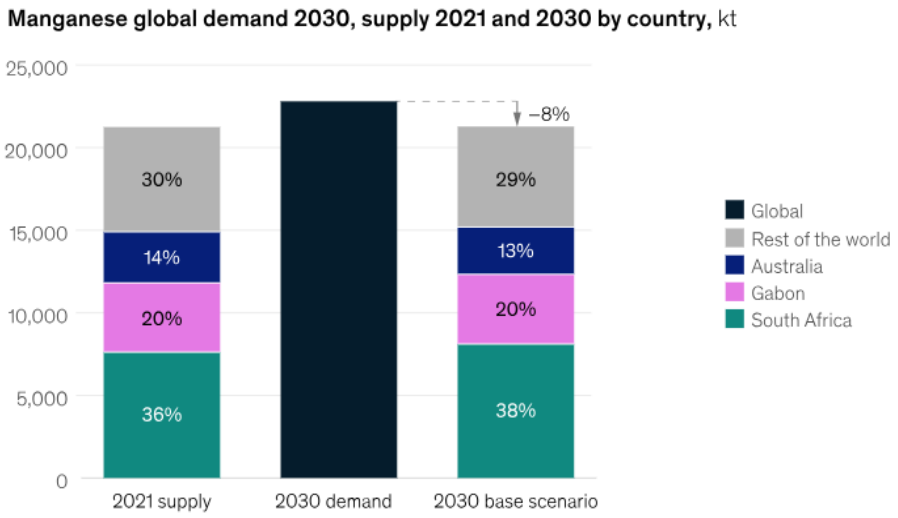
Figure 78: Cobalt Supply and Demand Projection by 2030[15]



Experts foresee a 15% increase in cobalt supply by 2030, mainly driven by a reduction in the material used to produce Li-ion batteries.

[271] Campagnol, N., Hoffman, K., Lala, A. & Ramsbottom, O. (2017). The Future of Nickel: A Class Act. *McKinsey & Company*, (November 28). https://www.mckinsey.com/industries/metals-and-mining/our-insights/the-future-of-nickel-a-class-act

Figure 79: Manganese Supply and Demand Projection by 2030[15]



Experts anticipate that the demand for manganese worldwide will exceed the supply by 2030, mainly due to a potential increase in market shares of lithium manganese iron phosphate cathode chemistries.[6]

24.6 Construction and Development

Puerto Rico has no lithium mining industry, and there is currently no information indicating active exploration or extraction of lithium resources on the Island. The mineral resources in Puerto Rico primarily focus on industrial minerals such as sand, gravel, and volcanic rock, with limited documented lithium occurrences.

The Thacker Pass Project[272], developed by Lithium Americas Corp. in Humboldt County, Nevada, is a significant lithium mining initiative to produce battery-grade lithium carbonate to support the growing demand for electric vehicles and renewable energy technologies. The project is located within the McDermitt Caldera and encompasses approximately 4,236 hectares. The feasibility study for Thacker Pass indicates a two-phase development plan, with an initial production capacity of 40,000 tons per annum of lithium carbonate, expected to double in the second phase. The project has received necessary regulatory approvals, including a Record of Decision from the Bureau of Land Management and a reclamation permit from the Nevada Division of Environmental Protection. Construction began in early 2023, with mechanical completion targeted for 2027 and full production capacity anticipated by 2028.

24.6.1 Thacker Pass Timeline of Engineering, Procurement, and Construction Process

- **Feasibility Study (Approx. 1 to 2 years):** The feasibility study for Thacker Pass was completed and is documented under National Instrument 43-101, providing essential details on the project's viability,

[272] Lithium Americas Corp. (formerly 1397468 B.C. Ltd.). Feasibility Study National Instrument 43-101 Technical Report for the Thacker Pass Project, Humboldt County, Nevada, USA. Effective Date: November 2, 2022. Prepared by: Daniel Roth, P.E., P.Eng. (M3); Walter Mutler, P.Eng. (EXP); Laurie Tahija, QP-MMSA (M3); Kevin Bahe, P.E. (Sawtooth); Eugenio Iasillo, P.E. (Process Engineering LLC); Paul Kaplan, P.E. (NewFields); Kevin Martina, P.Eng. (Wood); Tyler Cluff, RM-SME (Piteau); Benson Chow, RM-SME (Sawtooth); Bruce Shannon, P.E. (ITAC).

resource estimates, and environmental considerations. This foundational phase is crucial for moving forward with permitting and construction.

- **Permitting and Approvals (1-3 years)**: The project successfully navigated the permitting process, receiving a Record of Decision from the Bureau of Land Management in early 2021. This phase included environmental assessments and community consultations, which are critical for compliance with regulatory requirements.
- **Detailed Engineering (Approx. 1 to 2 years)**: While specific timelines for completion are not provided, detailed engineering phases in similar projects typically last about 1 to 2 years. Given that it started in early 2023, it may be expected to continue through 2024 or into early 2025. This involves designing processing facilities and infrastructure necessary for operations.
- **Procurement (Approx. 1 to 2 years)**: Procurement efforts are ongoing, focusing on sourcing materials and equipment needed for construction. This phase is vital to ensure all resources are available when construction ramps up.
- **Construction (2023-2027)**: Construction began in early 2023 with initial activities, such as site preparation and geotechnical drilling. Major construction is expected to commence in the second half of 2024, targeting mechanical completion by 2027.
- **Commissioning and Start-up (2027-2028)**: After construction, commissioning will occur over approximately 6-12 months, with full production capacity anticipated by 2028.

Development Risks

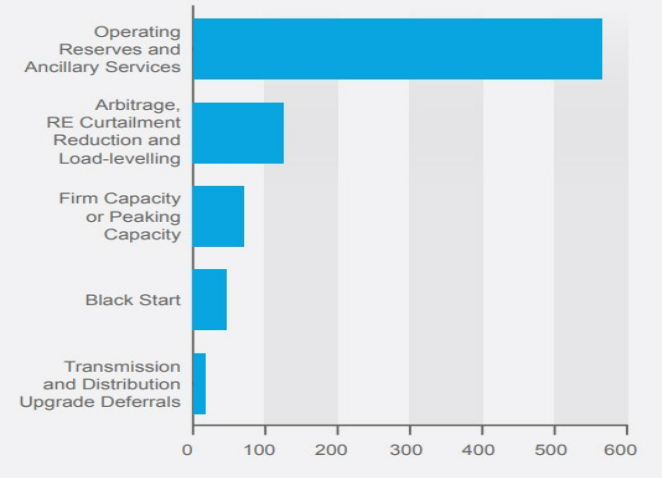
- **Environmental Risks**: The Thacker Pass Project faces scrutiny regarding its environmental impacts, particularly concerning water usage and potential disruption to local ecosystems. These concerns necessitate rigorous environmental assessments to mitigate risks.
- **Regulatory Risks**: Navigating complex regulatory frameworks can lead to delays in project timelines. Although most permits have been secured, ongoing discussions about groundwater usage may affect future phases of development.
- **Economic Risks**: The capital cost estimate for Phase 1 is approximately $2.93 billion, reflecting potential economic uncertainties related to fluctuations in lithium prices that could impact project financing.
- **Social Risks**: Community opposition due to environmental concerns could hinder project development. Engaging local communities through participatory processes is essential for obtaining a social license to operate.
- **Logistical Challenges**: The remote location of the Thacker Pass Project may present logistical difficulties related to transporting materials necessary for construction.
- **Technological Risks**: While advancements in extraction technologies promise improving efficiency, their commercial viability remains uncertain, introducing risks into project planning.

The Thacker Pass Project effectively illustrates the timeline for construction and development in lithium mining while highlighting various risks associated with such projects. Its structured approach—from feasibility studies to permitting and construction—demonstrates the complexities of bringing a lithium project to fruition while navigating environmental, regulatory, economic, social, logistical, and technological challenges.

24.7 Operation

The primary function of Li-ion batteries will be to provide stability for the Puerto Rico electric grid and to store solar and wind energy for use during the evening hours. Utility-scale battery energy storage systems can help to balance the demand and supply of energy (e.g., reduce curtailment of the renewables Independent Power Producers), peak shaving, and provide ancillary services (e.g., frequency and voltage regulation and black start of large generators),[273] as seen in Figure 80.

Figure 80: Utility-Scale Battery Storage Cumulative Capacity (MW) by Different Types of Operation According to the U.S. Energy Information Administration [274]



The desired use of Li-ion batteries impacts their degradation rate and, consequently, the lifetime expectancy of the battery. If, for example, the Li-ion batteries are primarily utilized to maintain the frequency of the electrical system, which requires rapid and frequent charge and discharge cycles, their degradation rate will be higher than in other operational modes that require fewer charge and discharge cycles. Regarding reliability and resilience, Li-ion batteries tend to possess a high energy density and a long lifetime. These batteries' operation and performance can be safe if handled at the proper temperatures.[275]

[273] Anil, M., & Rejikumar, G. (2023). Life Cycle Analysis of Lithium-ion Batteries: An Assessment of Sustainability Impact. In *2023 International Conference for Advancement in Technology (ICONAT)*, (pp. 1-5). Goa, India.
[274] Bowen, T., & Chernyakhovskiy, I. (2019). Grid-scale battery storage frequently asked questions. *National Renewable Energy Laboratory*. https://www.nrel.gov/docs/fy19osti/74426.pdf
[275] Leng, F., Tan, C.M. & Pecht, M. (2015). Effect of Temperature on the Aging Rate of Li Ion Battery Operating above Room Temperature. *Scientific Reports*, 5(1), 12967. https://doi.org/10.1038/srep12967

24.8 Sustainability

Li-ion batteries have emerged as a pivotal technology in transitioning to renewable energy and electric vehicles (EVs), offering significant environmental benefits. However, their production and life cycle also present considerable challenges that must be addressed to maximize their sustainability. This overview discusses the environmental benefits and issues associated with Li-ion batteries, focusing on land use, technology footprint, greenhouse gas (GHG) emissions, and water usage.

24.8.1 Environmental Benefits and Issues

Land Use

Li-ion batteries play a crucial role in facilitating the transition to renewable energy sources by providing essential energy storage solutions for variable renewable energy resources, such as solar and wind. This capability helps reduce reliance on fossil fuels, which typically require extensive land for extraction and infrastructure. By enabling a shift towards cleaner energy, Li-ion batteries can decrease the land use associated with fossil-based energy sources.[276]

Conversely, mining lithium and other materials for Li-ion batteries entails significant land use changes. For instance, recent studies indicate that the Atacama salt flat in Chile is sinking at a rate of 1 to 2 centimeters (0.4 to 0.8 inches) per year due to lithium brine extraction, as researchers from the University of Chile reported. Utilizing satellite data collected between 2020 and 2023, the study verified deformations in the Earth's crust, particularly in the southwest of the salt flat where lithium miners operate.[277] In addition, cobalt mining in the Democratic Republic of Congo has been reported to impact vast areas of land, with artisanal mining activities contributing to significant environmental degradation. The exact figures regarding land affected can vary, but it is widely recognized that mining operations can lead to habitat destruction and soil degradation.[278]

Land use impacts vary by region, with areas with stringent environmental regulations experiencing lower impacts than less regulated regions. Effective land reclamation practices can mitigate these effects, demonstrating that rehabilitation efforts are essential for sustainable mining practices.

Technology Footprint

Li-ion batteries enable efficient energy storage and are widely used in various applications, including EVs and smart grids. Their high energy density and long cycle life make them suitable for these roles, allowing for effective management of energy supply and demand. Research indicates that Li-ion batteries achieve high energy efficiency levels, often exceeding 90% in various applications.[279]

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[276] Llamas-Orozco, J. A., Meng, F., Walker, G. S., Abdul-Manan, A. F. N., MacLean, H. L., Posen, I. D., & McKechnie, J. (2023). Estimating the environmental impacts of global lithium-ion battery supply chain: A temporal, geographical, and technological perspective. *PNAS Nexus*, 2(11), pgad361. https://doi.org/10.1093/pnasnexus/pgad361 on page 12.

[277] Cambero, F. (2024). Lithium mining is slowly sinking Chile's Atacama salt flat, study shows. *Reuters*, (August 22). https://www.reuters.com/sustainability/land-use-biodiversity/lithium-mining-is-slowly-sinking-chiles-atacama-salt-flat-study-shows-2024-08-22/

[278] Davey, C. (2023). The environmental impacts of cobalt mining in Congo. *Earth.Org*, (March 28). https://earth.org/cobalt-mining-in-congo/

[279] Chen, T., Jin, Y., Lv, H., Yang, A., Liu, M., Chen, B., Xie, Y. & Chen, Q. (2020). Applications of Lithium-Ion Batteries in Grid-Scale Energy Storage Systems. *Transactions of Tianjin University*, 26(2), 208-217, (February 8). https://doi.org/10.1007/s12209-020-00236-w. on page 212.

Greenhouse Gas (GHG) Emissions

Li-ion batteries play a critical role in reducing GHG emissions by facilitating the adoption of renewable energy sources and electric vehicles. Implementing secondary materials through recycling can significantly alleviate the environmental burdens linked to extracting and processing primary raw materials. Direct recycling methods have been shown to offer the lowest environmental impacts, followed by hydrometallurgical and pyrometallurgical processes. Specifically, recycling can reduce GHG emissions by 61%, 51%, and 17%, depending on the recycling method used.[280]

GHG emissions associated with lithium-ion battery production vary significantly based on the materials and processes used. For instance, producing NMC811 batteries results in average emissions of approximately 79 kg CO_2 equivalent per kWh, while LFP batteries have lower emissions of about 56 kg CO_2 equivalent per kWh.[281] This variation highlights the importance of selecting battery chemistries that minimize environmental impact in the context of increasing demand for EVs and energy storage solutions.

Other Emissions

The environmental impacts of Li-ion batteries extend beyond their benefits in reducing vehicle GHG emissions. The production and disposal of these batteries present significant challenges, particularly concerning emissions during the mining and processing of raw materials and the end-of-life management of the batteries themselves.

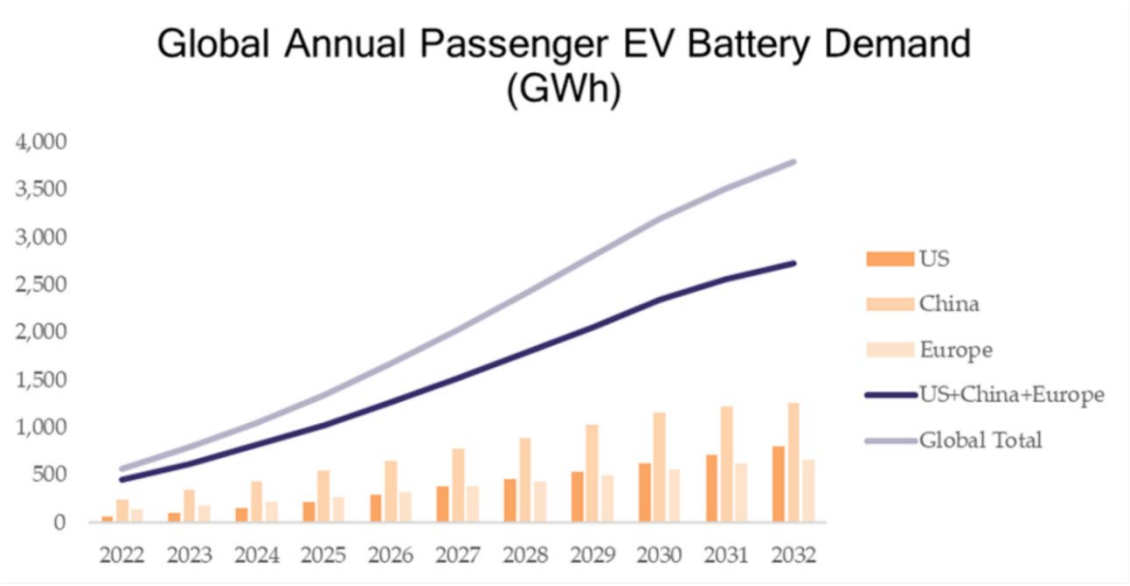
Mining for lithium and other essential minerals required for Li-ion batteries generates substantial GHG emissions. Approximately 40% of the climate impact associated with Li-ion battery production arises from the mining and processing stages. These processes are energy-intensive, often relying on coal-fired power plants, especially in China, which dominates the global Electric Vehicle (EV) battery supply chain (Figure 81). As a result, the production of lithium-ion batteries can produce more carbon dioxide emissions than that of traditional gasoline-powered vehicles. The cumulative energy demand for producing an average lithium-ion battery is three times greater than that of a conventional battery, raising concerns about its environmental footprint.

The disposal of Li-ion batteries also poses significant risks. A staggering 98.3% of these batteries end up in landfills, where they can leach toxic heavy metals into the soil and groundwater. This not only threatens local ecosystems but also raises public health concerns. Landfill fires caused by improperly disposed of batteries have become increasingly common. Reports indicate that a landfill in the Pacific Northwest experienced 124 fires over three years due to Li-ion batteries. These fires can burn for extended periods, complicating containment efforts and releasing harmful pollutants into the atmosphere.

[280] Llamas-Orozco, J. A., Meng, F., Walker, G. S., Abdul-Manan, A. F. N., MacLean, H. L., Posen, I. D., & McKechnie, J. (2023). Estimating the environmental impacts of global lithium-ion battery supply chain: A temporal, geographical, and technological perspective, p.11.

[281] Llamas-Orozco, J. A., Meng, F., Walker, G. S., Abdul-Manan, A. F. N., MacLean, H. L., Posen, I. D., & McKechnie, J. (2023). Estimating the environmental impacts of global lithium-ion battery supply chain: A temporal, geographical, and technological perspective, pp. 5-6.

Figure 81: Global Annual Passenger Electric Vehicle Battery Demand Forecast Through 2032[25]



Governments are promoting recycling efforts to mitigate these environmental issues. Yet, rates remain alarmingly low—only about 5% of lithium-ion batteries are recycled compared to 99% of lead-acid car batteries in the United States. The recycling process can be hazardous; mishandling during disassembly can lead to short-circuiting and combustion, releasing toxic fumes. The diverse chemistries and constructions of Li-ion batteries complicate the development of efficient recycling systems, making it often more economical for manufacturers to source newly mined materials rather than recycled ones.[282]

24.8.2 Water Usage

Water Consumption in Lithium Extraction

Lithium extraction often employs brine evaporation, which requires substantial amounts of water. This technique involves pumping large volumes of brine from underground salt flats to the surface, where it is left to evaporate in large ponds. Reports indicate that extracting one ton of lithium carbonate can consume between 100 to 800 cubic meters of water, depending on the specific deposit being exploited.[283] In regions like the Lithium Triangle – spanning parts of Argentina, Bolivia, and Chile – lithium mining can consume up to 65% of local freshwater resources, raising significant concerns about its sustainability in areas that receive less than four inches of rain annually.[284]

Impact on Local Communities and Ecosystems

The depletion of water resources due to lithium mining has dire consequences for local communities and ecosystems. Indigenous populations living near extraction sites are particularly vulnerable to water

[282] Institute for Energy Research. (2023). Environmental impacts of lithium-ion batteries. *Institute for Energy Research*, (May 11). https://www.instituteforenergyresearch.org/renewable/environmental-impacts-of-lithium-ion-batteries/
[283] Vera, M. L., Torres, W. R., Galli, C. I., Chagnes, A., & Flexer, V. (2023). Environmental impact of direct lithium extraction from brines. *Nature Reviews Earth & Environment*, 4(4), 149–165. https://doi.org/10.1038/s43017-022-00387-5
[284] Rodriguez, A. (2023). Lithium Extraction and its Impacts on Indigenous Communities. *International Relations Review*, (October 11). https://www.irreview.org/articles/2023/10/11/lithium-extraction-and-its-impacts-on-indigenous-communities

shortages, which can threaten their agricultural practices and overall livelihoods. For example, in Chile, privatization of water rights has complicated regulatory efforts, leading to increased competition for already limited water supplies. The environmental stress lithium mining causes affects human populations and diminishes local wildlife, as seen with endemic species like the James' and Andean flamingos, whose populations have declined significantly due to habitat changes linked to mining activities.[285]

Wastewater Management Challenges

Effective management of wastewater generated during lithium extraction is crucial to prevent contamination of local water supplies. Traditional extraction methods often leave behind spent brines that can contain harmful chemicals and heavy metals. Without proper treatment and disposal, these pollutants can leach into groundwater and surface waters, posing long-term ecological and health risks.[286] Newer extraction technologies are being developed to reduce freshwater consumption and minimize environmental impacts. For instance, a recent study highlights a method using redox couple electrodialysis that significantly lowers water usage and energy consumption compared to conventional brine evaporation techniques.[287]

Overview of Redox-Couple Electrodialysis (RCE)

The RCE method utilizes electricity to move lithium ions through a solid-state electrolyte membrane, concentrating lithium from brines with low concentrations into a high-purity solution. This process is highly efficient, using less than 10% of the electricity required by traditional brine extraction methods and achieving nearly 100% lithium selectivity. This efficiency is crucial as it reduces the energy footprint and minimizes the ecological impact of extensive land use and water consumption inherent in traditional extraction methods.

In addition to its environmental benefits, RCE is also cost-effective. Estimates suggest it can produce high-purity lithium hydroxide for $3,500 to $4,400 per ton, significantly lower than the approximately $9,100 per ton cost associated with current dominant extraction technologies. Given the volatile market price for battery-grade lithium carbonate, which has soared from around $15,000 per ton to as high as $80,000 during shortages, this new method could stabilize supply and pricing in the lithium market.[288]

The RCE method addresses several environmental concerns related to lithium extraction:[289]

- **Reduced Water Consumption**: Traditional lithium extraction methods can consume vast amounts of water, exacerbating scarcity in arid regions. The RCE technique significantly lowers freshwater usage, making it more sustainable in regions with limited water.
- **Lower Chemical Use**: Conventional methods often involve heavy use of potentially toxic chemicals during extraction. By streamlining the extraction process and reducing reliance on these chemicals, RCE minimizes the risk of environmental contamination.

[285] Id.
[286] Vera, M. L., Torres, W. R., Galli, C. I., Chagnes, A., & Flexer, V. (2023). Id.
[287] Golden, M. (2024). New technology extracts lithium from briny water. *Stanford University*. https://news.stanford.edu/stories/2024/08/new-technology-extracts-lithium-from-brines-inexpensively-and-sustainably
[288] Cui, Y., Xu, R., Zhang, G., & Stanford University. (2024). New technology extracts lithium from brines inexpensively and sustainably. *Matter*.
[289] Id.

- **Wastewater Utilization**: The RCE method can also extract lithium from various saline waters, including wastewater from oil production and seawater. This versatility allows for better resource management and reduces the pressure on freshwater sources.

The scalability of the RCE method shows promise for industrial applications. Initial experiments have demonstrated that increasing the scale of the device does not compromise its efficiency or selectivity. However, there are still areas for further research, particularly regarding membrane stability when extracting lithium from seawater. As researchers continue to optimize this technology and explore its applications on a larger scale, there is optimism that RCE could play a critical role in meeting the growing demand for lithium while minimizing its environmental footprint. The ongoing development of such innovative extraction techniques is essential for supporting the transition to EVs and renewable energy storage systems without compromising water resources or ecological health.

24.8.3 Life Cycle of Lithium-Ion Batteries

The sustainability of Li-ion batteries is increasingly scrutinized, particularly regarding their life cycle, from production to disposal. The following analysis encompasses the environmental impacts of their manufacturing, usage, and end-of-life management, highlighting the importance of recycling and sustainable practices.

Raw Material Extraction and Processing

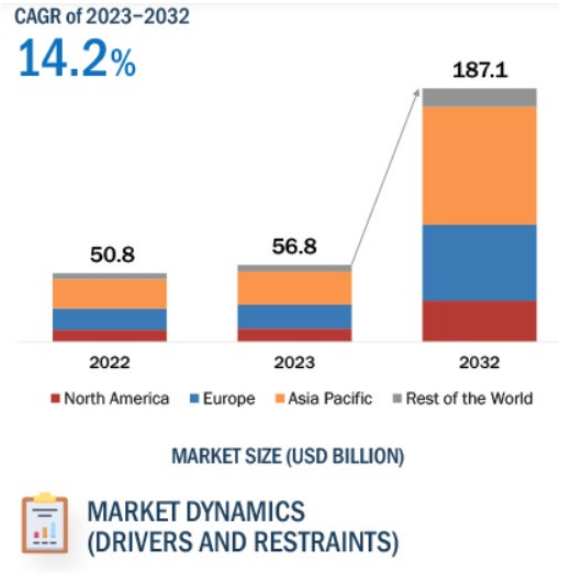
The production of Li-ion batteries begins with the extraction of essential raw materials, including lithium, cobalt, and nickel. The global demand for these materials is projected to increase significantly. For instance, the demand for lithium-ion battery cells is expected to surge from approximately 700 gigawatt-hours (GWh) in 2022 to about 4,700 GWh by 2030.[290] This dramatic rise underscores the need for sustainable sourcing practices to mitigate the environmental impacts of mining and processing these materials.

Usage Phase

During their operational life, Li-ion batteries are crucial for reducing reliance on fossil fuels, particularly in EVs—however, their sustainability hinges on efficient energy use and management throughout their lifespan. The growing demand for EVs is expected to significantly increase the number of Li-ion batteries by 2050, necessitating a robust framework for managing their lifecycle sustainably.

[290] Statista Research Department. (2024). Global Li-ion battery demand 2022-2030. *Statista*, (June 28). https://www.statista.com/statistics/1419502/global-lithium-ion-battery-demand-forecast/ on page 22.

Figure 82: Market Size Usage Phase[291]



End-of-Life Management

Proper disposal and recycling of Li-ion batteries are critical to mitigating environmental risks. If not correctly managed, toxic materials from these batteries can leach into soil and water systems. Recycling saves valuable materials, such as lithium and cobalt, and reduces the need to extract virgin resources. According to the Environmental Protection Agency's (EPA) draft Life Cycle Assessment, effective recycling can significantly reduce the carbon footprint associated with battery production by reintroducing recovered materials into the supply chain.

24.8.4 Recycling Challenges and Opportunities

The recycling infrastructure for lithium-ion batteries is still developing. Key challenges include inadequate collection systems, diverse battery chemistries that complicate recycling processes, and economic factors often making recycling less attractive and cost-effective than raw material extraction. Despite these hurdles, advances in recycling technologies are promising. For instance, experts have identified direct cathode recycling as a highly effective method that can reduce energy use and carbon emissions compared to traditional methods.

Manufacturers are encouraged to design batteries with recyclability in mind to enhance sustainability. Innovations in battery chemistry and structure could simplify disassembly and improve material recovery. Legislative measures may also play a crucial role in driving these changes by mandating recycling practices and promoting the sustainable sourcing of materials.

[291] Lithium-Ion Battery Market Size, Share & Trends. (2025). *Markets and Markets*, (June). www.marketsandmarkets.com/Market-Reports/lithium-ion-battery-market-49714593.html

25.0 *New Resource Option: Solar*

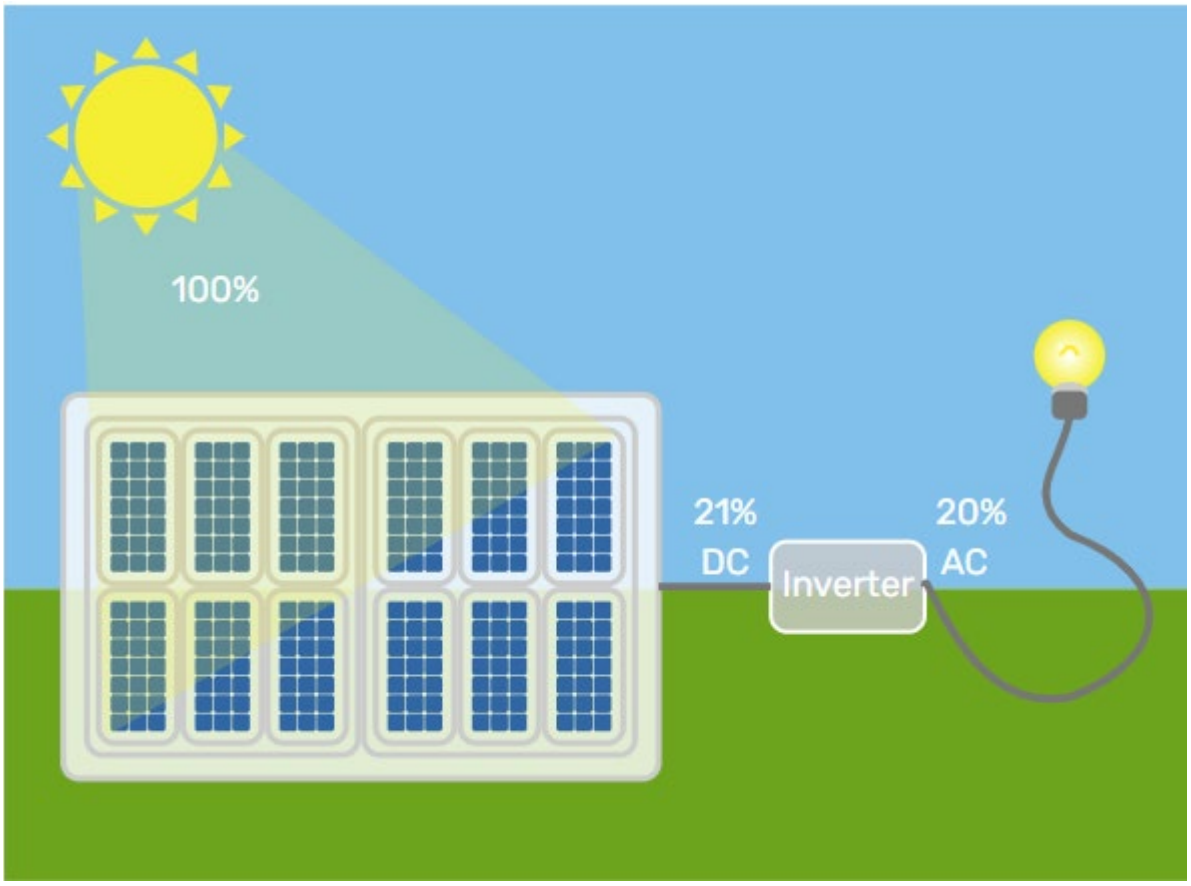
25.1 Description

Solar technologies can harness sunlight to generate electrical energy. For example, solar photovoltaic (PV) panels directly use sunlight to yield electricity, while concentrated solar power (CSP) systems concentrate solar radiation to heat a working fluid, which then produces electricity. [292] Developers use various energy storage systems, including batteries, to store generated energy. –Of all these technologies, people most commonly recognize PV technology in solar panels as the most widely adopted. This report examines well-established solar technologies and innovative solutions that could transform Puerto Rico's energy landscape.

PV technology is the most common form of solar power generation. When sunlight strikes a solar panel, PV cells absorb energy, creating electrical charges that respond to an internal electrical field, producing electricity (Figure 83). A PV system includes more than just the panels themselves. It also consists of mounting structures that orient the panels towards the sun and components that convert the direct current (DC) electricity the panels produce into alternating current (AC) for household use.[293] People can install PV technology on rooftops or the ground, with rooftop installations currently being the most common choice in Puerto Rico. Innovative applications, such as floating solar panels, PV-integrated windows, and solar roadways, are also emerging in countries like the United States, China, and the Netherlands.

[292] U.S. Department of Energy. (n.d.). *How Does Solar Work?* https://www.energy.gov/eere/solar/how-does-solar-work
[293] U.S. Department of Energy. (n.d.). *Solar Photovoltaic Technology Basics*. https://www.energy.gov/eere/solar/solar-photovoltaic-technology-basics

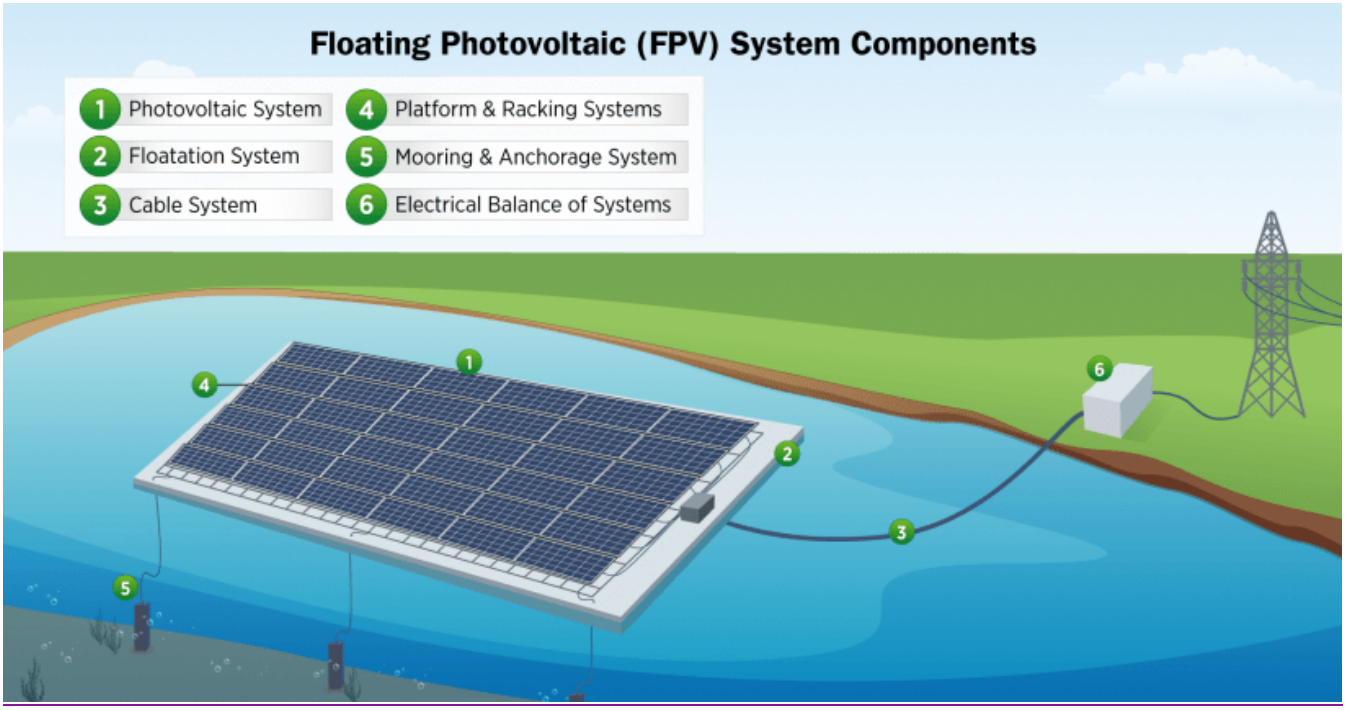
Figure 83: Photovoltaic Conversion Efficiency[294]



Floating solar photovoltaic systems (FPV), or “floatovoltaics,” involves mounting solar panels on floating platforms placed on reservoirs, lakes, and other large, human-made bodies of water, and near-shore and offshore marine sites. FPV systems address land-use concerns and maximize space efficiency using previously unused water surfaces. Currently, in the early stages of commercial deployment, FPV systems shade the underlying bodies of water, helping to reduce water evaporation. They also have the potential to enhance solar panel efficiency through the cooling effect that the water beneath them provides. FPV systems support renewable energy goals by allowing the flexibility to install effective solar energy technology in locations where land is scarce or costly. [295]

[294] Center for Sustainable Systems, University of Michigan. (2024). *Photovoltaic Energy Factsheet.* Pub. No. CSS07-08. https://css.umich.edu/publications/factsheets/energy/photovoltaic-energy-factsheet
[295] U.S. Department of Energy. (n.d.). Floating photovoltaics (FPV). *Office of Energy Efficiency and Renewable Energy*. Retrieved October 30, 2024, from https://www.energy.gov/eere/solar/dual-use-photovoltaic-technologies

Figure 84: Floating Solar System



CSP systems harness solar energy by using mirrors or lenses to reflect and focus sunlight onto a receiver, where the concentrated light heats a working fluid. This thermal energy then spins turbines or power engines to generate electricity. Unlike PV panels, which generate electricity directly from sunlight, CSP relies on concentrating solar heat to produce power. Additionally, CSP's versatility enables industries to use its thermal energy in various applications, such as water desalination, food processing, and enhanced oil recovery. Designers typically create CSP systems for utility-scale projects, with the two primary configurations being power tower and linear systems. Power towers arrange mirrors around a central tower that serves as the receiver, while linear systems use parabolic mirrors to focus sunlight onto tubes filled with heat-transfer fluids. Smaller-scale[296] CSP units, such as dish/engine systems, offer distributed applications with outputs ranging from five to 25 kilowatts. Spain, the United States, and China have implemented CSP technologies primarily in large-scale projects, positioning them at the forefront of global adoption and innovation.[297] These countries have also pioneered thermal storage solutions, enabling CSP plants to produce electricity even at night.

While CSP offers a unique approach to solar energy with its thermal storage capabilities, the focus will be on PV technology due to its wider adoption and ongoing advancements.

25.2 Technology Maturity

Solar photovoltaic (PV) technology is widely recognized as mature and highly efficient; it is now entering the later stages of technological development. Over the past decade, advancements in solar panel

[296] U.S. Department of Energy. (n.d.). *How Does Solar Work?* https://www.energy.gov/eere/solar/how-does-solar-work
[297] National Renewable Energy Laboratory (NREL). (2024). *Concentrating Solar Power Projects by Country*. https://solarpaces.nrel.gov/by-technology

efficiency—often exceeding 20%—along with significant cost reductions and increased durability have solidified solar PV as one of the most viable renewable energy options. These improvements have also extended the typical panels' lifespan, with warranties reaching up to 25 years. In the first half of 2024 alone, the U.S. installed 15.6-gigawatts alternating current of solar capacity—a 55% increase compared to the same period in 2023—with total installations projected to reach 42 gigawatts alternating current by the end of the year, reflecting a 25% growth over 2023 and underscoring its continued commercial scalability.[298]

In contrast, floating solar technology is still in the early stages of commercial deployment along its maturity curve. This emerging technology leverages bodies of water for solar installations, offering unique advantages such as reduced land use and improved panel efficiency due to cooling effects. While it has not yet reached the level of widespread adoption seen with land-based solar PV, ongoing pilot projects and small-scale deployments demonstrate its potential to make a significant contribution to the renewable energy mix.

Despite its technological maturity, solar energy accounts for only 3.9% of total U.S. electricity generation, highlighting limited widespread adoption rather than a lack of technical readiness. The U.S. grid remains heavily dependent on fossil fuels, with natural gas and coal making up 60% of the energy mix. While utility-scale solar continues to expand, rooftop PV—an option for distributed power generation without requiring land—remains underutilized, representing only 23% of total installed PV capacity.

A study conducted in Minnesota to explore the potential of rooftop solar found that the average technical potential is 0.01117 kW of capacity per square foot of suitable roof area, with an estimated 13 kWh of solar energy generation per square foot per year for both medium and large buildings. These ratios are based on estimates of rooftop orientation.[299]

In Puerto Rico, however, residents have adopted rooftop solar much faster. Over 100,000 households have installed rooftop systems, adding approximately 3,000 new systems each month. Federal funding for vulnerable families, the high cost of utility-supplied power, and customers' desire to improve their power supply resiliency have driven this rapid adoption, positioning Puerto Rico as a leader in rooftop solar deployment.

On the Mainland, adoption rates are much lower. Hawaii leads the way, covering 12.46% of solar-eligible buildings, while the national average is only 0.93%. Federal programs, such as those implemented in Puerto Rico, could provide a model for overcoming financial barriers and accelerating the growth of residential solar nationwide.

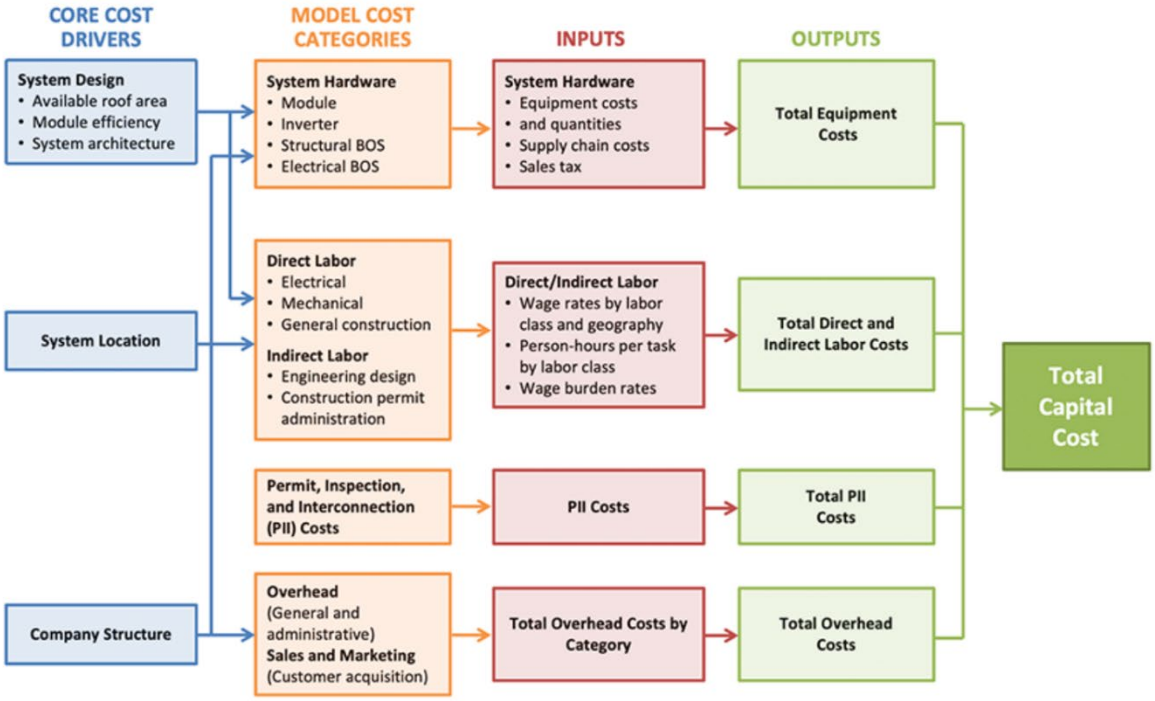
25.3 Cost

The data on capital costs, O&M costs, and energy prices for solar PV systems come from various reputable sources and reports that track trends in solar energy costs. Figure 85 illustrates the bottom-up approach used by the National Renewable Energy Laboratory (NREL) for PV cost benchmarking.

[298] U.S. Department of Energy. (n.d.) Quarterly Solar Industry Update, accessed December 12, 2024. https://www.energy.gov/eere/solar/quarterly-solar-industry-update#:~:text=About%20560%20gigawatts%20direct%20current,about%20a%20quarter%20from%202023

[299] Office of Energy Efficiency and Renewable Energy. (n.d.) Hutchinson, Minnesota: Evaluating Local Energy Generation Potential. *U.S. Department of Energy*, accessed December 12, 2024. https://www.nrel.gov/docs/fy19osti/71611.pdf

Figure 85: PV Cost Benchmarking Approach[300]



As of 2023, the capital cost for utility-scale solar PV systems decreased by approximately 69% from 2010 to 2023. Technological advancements and increased competition among manufacturers primarily drive this reduction, aligning with findings from the NREL, which publishes annual benchmarks for installed solar PV costs. Over the past decade, the cost of solar panels has dropped by nearly 80%, reflecting the impact of economies of scale and technological advancements on production costs. Projections suggest a further 15-20% decrease in capital costs by 2033 due to ongoing innovation and market expansion.[301] [302]

Experts estimate current fixed O&M costs for solar PV systems in the continental USA at around $10 to $20 per kilowatt per year, which aligns with industry standards for routine maintenance and inspections, as NREL's cost benchmarks corroborate. Variable O&M costs in the continental USA are minimal, typically ranging from $0.00 to $0.02 per kilowatt-hour, as solar PV systems do not incur fuel costs and have no moving parts. Comparing the costs of solar PV with those of natural gas, coal, and wind energy provides context for evaluating solar energy's competitiveness within the broader energy landscape. For instance, capital costs for natural gas plants range from $900 to $1,200 per kilowatt, while coal plants have capital costs between $2,000 and $3,500 per kilowatt. Costs in Puerto Rico are significantly higher.

The dramatic reduction in the LCOE from solar PV globally—dropping from $0.35 per kilowatt-hour in 2010 to around $0.05 per kilowatt-hour in 2023—is well documented in various industry reports. Future

[300] See: https://www.researchgate.net/figure/Residential-PV-model-structure_fig7_309430950
[301] National Renewable Energy Laboratory. (n.d.). Solar installed system cost analysis. https://www.nrel.gov/solar/market-research-analysis/solar-installed-system-cost.html
[302] National Renewable Energy Laboratory. (2023). As PV market evolved in the last year, prices went up, prices went down. https://www.nrel.gov/news/program/2023/as-pv-market-evolved-in-the-last-year-prices-went-up-prices-went-down.html

projections indicate that LCOE will continue to decline, with estimates suggesting it could reach between $0.03 and $0.04 per kilowatt-hour by 2033 globally, an effect which could trickle to Puerto Rico, enhancing solar energy's competitiveness against other energy sources.[303] [304] [305]

However, solar PV energy is more expensive in island environments like Puerto Rico. This is due to the higher transportation costs, the limited land availability, making it more challenging to develop large-scale solar farms, and higher labor and installation costs. As such, considering the results from the 2025 IRP study, the LCOE costs range from $0.09 per kilowatt-hour to $0.16 per kilowatt-hour.

Floating solar systems present a promising but slightly more costly alternative in specific contexts. Fixed O&M costs for floating solar systems are estimated at $15.5 per kilowatt per year, reflecting the unique challenges of maintaining systems in aquatic environments, such as potential wear from water exposure and the need for specialized equipment. While floating solar systems are still emerging, their LCOE is approximately $56.6 per megawatt-hour or $0.06 per kilowatt-hour. This estimate places floating solar systems at a slightly higher cost than conventional land-based PV systems. However, it offers significant advantages, particularly in areas with limited land availability or where water bodies can be utilized for energy production without competing with agricultural or residential land use. [306]

25.4 Supply-Chain

Supply chain constraints in the solar industry present several challenges that could impact production and availability. One primary concern is the availability of raw materials, particularly polysilicon, which is essential for solar panel production. The production of polysilicon is concentrated in a few countries, particularly China, which poses a risk if geopolitical tensions or trade policies disrupt supply. The global demand for solar panels has surged, leading to potential bottlenecks in manufacturing capacity. Although production volumes have increased, scaling quickly to meet this demand can be challenging, especially for newer and more advanced technologies like bifacial panels or perovskite cells.[307]

Global transportation and logistics were severely disrupted by the COVID-19 pandemic, revealing vulnerabilities in the infrastructure. Shipping delays and increased costs have impacted the delivery of solar components, and these challenges persist as the industry continues to grow, potentially leading to delays in project timelines. Furthermore, the production of solar panels relies on critical minerals such as silver, copper, and rare earth elements. The availability of these materials could be constrained by environmental policies, mining regulations, or export restrictions, which may increase costs or limit production.

As of 2023, global production of solar panels has reached over 250 gigawatts (GW) annually, reflecting significant growth from just 40 GW in 2013. China dominates this market, accounting for approximately 70% of global solar panel production. While the solar industry is highly mature and scalable with

[303] Ayres, D. & Zamora, L. (2024). Renewable power generation costs in 2023. *International Renewable Energy Agency*, Abu Dhabi. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2024/Sep/IRENA_Renewable_power_generation_costs_in_2023.pdf
[304] National Renewable Energy Laboratory. (2023). Annual technology baseline: Utility-scale PV. https://atb.nrel.gov/electricity/2023/utility-scale_pv
[305] International Renewable Energy Agency. (2023). Renewable power generation costs in 2022. https://www.irena.org/Publications/2023/Aug/Renewable-Power-Generation-Costs-in-2022
[306] National Renewable Energy Laboratory. (2021). Floating Photovoltaic System Cost Benchmark: Q1 2021 Installations on Artificial Water Bodies. https://www.nrel.gov/docs/fy22osti/80695.pdf
[307] U.S. Department of Energy. (2022). Acute Shortages of Solar Equipment Poses Risks to the Power Sector. https://www.energy.gov/sites/default/files/2022-06/June%202022%20DOE%20Solar%20Market%20Update.pdf

established manufacturing processes and supply chains, the readiness level for newer technologies like perovskite solar cells remains in the development and early commercialization stages, potentially limiting their immediate market impact.

Access to raw materials presents additional risks. While silicon is readily available, the solar industry faces additional risks due to its dependence on other critical materials such as silver and copper. These materials are susceptible to price volatility and supply disruptions caused by mining operations, geopolitical events, and environmental regulations. Policy impacts such as tariffs, export restrictions, and environmental regulations could further affect the availability and cost of raw materials. For instance, if major producers like China impose export restrictions on polysilicon or rare earth elements, it could disrupt global supply chains and increase costs.[308] Moreover, mining activities for critical minerals can lead to environmental degradation and social conflicts, potentially resulting in stricter regulations or bans on mining in certain regions, further constraining supply.

25.5 Construction and Development

The engineering, procurement, and construction (EPC) process for solar PV projects typically involves four main phases:

- Project Development and Planning: In the initial phase, developers identify suitable locations, obtain necessary permits, secure funding, and develop detailed project plans.
- Procurement: This phase involves purchasing solar panels, inverters, racking systems, and other components. Supply chain challenges, such as global logistics, raw material shortages, and quality control issues, can impact availability and lead times. To mitigate these risks, a well-planned procurement strategy is essential.
- Construction: This phase involves site preparation, foundation construction, installation of solar panels and equipment, and electrical connections. The specific construction activities will vary depending on whether the project is land-based or floating.
- Testing and Commissioning: In the final phase, the system's performance is tested, safety compliance is ensured, and the system is connected to the grid.

25.5.1 Key Considerations for Land-Based and Floating Projects

Land-based projects require a suitable land area, bring the potential for land acquisition challenges, and must comply with land-use regulations. Floating projects involve additional considerations for water depth, wave conditions, and water and marine permits. Both project types face common challenges, such as supply chain disruptions, component availability, and permitting processes.

25.5.2 Mitigation Strategies

To mitigate these challenges and reduce costs, project developers can implement strategies, such as diversifying supply chains, developing contingency plans, including options for alternate locations, utilizing efficient project management techniques, adopting advanced technologies, and supporting domestic solar

[308] Abdelilah, Y., Bahar, H., Briens, F., Bojek, P., Criswell, T., Kurumi, K., Moorhouse, J., Rodriguez, G. & Veerakumar, K. (2022). Solar PV Global Supply Chains. *International Energy Agency*, (July). https://www.iea.org/reports/solar-pv-global-supply-chains/executive-summary

manufacturing. [309] By considering these factors and implementing mitigation strategies, project developers can enhance their solar EPC projects' efficiency and potential success.

25.6 Operation

Solar technology focuses on simplicity and efficiency, making it an attractive option for widespread adoption. Maintenance requirements for solar systems are minimal, with most systems needing only periodic cleaning of the panels to remove dirt and debris that could reduce efficiency. Inspections are generally recommended annually to check for issues, such as loose connections or inverter performance. The frequency of maintenance can vary depending on the environment and the scale and details of the installation design. Still, solar systems require significantly less maintenance than traditional fuel-based energy systems.

Solar technology is highly dependable, with modern solar panels typically offering warranties of 25 years or more. The reliability of solar systems is further enhanced by the absence of moving parts, which reduces the likelihood of mechanical failures. However, solar energy generation depends on sunlight, so it is intermittent. Integrating energy storage solutions, like batteries, can partially mitigate this intermittency.

Resiliency is another strength of solar technology, particularly in distributed systems where power generation is spread across multiple locations. This decentralized approach makes solar systems less vulnerable to single points of failure, such as those that might occur in centralized power plants.

Overall, solar technology offers a reliable, low-maintenance, and resilient energy solution, making it a viable option for both large-scale utility projects and smaller, distributed applications. Unlike fuel-based technologies, solar does not require fuel transportation or logistics, further simplifying its operation and reducing ongoing costs.[310]

25.7 Sustainability

The increasing global demand for energy, coupled with the urgent need to transition to low-carbon sources, has fueled a surge in the deployment of PV solar energy systems. Compared to fossil-fuel-based power systems, PV significantly reduces pollutant and greenhouse gas (GHG) emissions. However, deploying PV solar technologies is not without its environmental considerations, including potential impacts on biodiversity, habitat disruption, climatic effects, resource consumption, and the challenge of responsibly disposing of large quantities of end-of-life panels. This section evaluates the benefits and potential environmental implications of implementing PV technologies. In addition, solar PV must be combined with other energy and storage sources to deliver a reliable electric supply that overcomes the hourly, daily, and seasonal variability in solar PV production.

When evaluating the sustainability of PV systems, it is essential to consider the entire life cycle, from raw material extraction to their disposal. This comprehensive approach encompasses acquiring raw materials, processing, manufacturing, operation, decommissioning, and treating and disposing of components. To

[309] Lawrence Berkeley National Laboratory. (n.d.). Utility-Scale Photovoltaic Project Development and Innovation. *Energy I-SPARK*. Retrieved October 30, 2024, from https://ei-spark.lbl.gov/generation/utility-scale-pv/project/innov

[310] U.S. Department of Energy. (n.d.). Photovoltaic Reliability and Standards Development. https://www.energy.gov/eere/solar/photovoltaic-reliability-and-standards-development

determine the carbon footprint of PV systems, all life cycle phases must be considered to gain a holistic understanding of their environmental impacts.

25.7.1 Potential Environmental Impacts of Photovoltaic Technologies

- Land Use: Depending on location, size, and design, ground-mounted PV systems could impact the natural habitat and biodiversity of the installation area. Some PV systems can be integrated into existing infrastructure (rooftop solar), while others require dedicated land areas (solar farms) or even water bodies (floating solar technology).
- Greenhouse Gas Emissions: GHG emissions refer to the amount of carbon dioxide and other gases released into the atmosphere during a product's life cycle. For PV, these emissions mainly occur during the early stages of manufacturing, transportation, and decommissioning. For example, manufacturing some PV cells requires energy-intensive processes that can increase their carbon footprint.
- Water Use: Water is used primarily for cleaning during maintenance throughout the life cycle of PV systems. Compared to other technologies, the water demand for PV systems is relatively low and does not pose a significant environmental concern.
- Hazardous Materials: The use of hazardous materials during the PV life cycle can be detrimental to both the environment and human health if not properly handled. Certain PV cells contain toxic metals, such as cadmium or lead, which can contaminate soil or water if damaged or improperly disposed of.

25.7.2 Addressing the Environmental Concerns

Land use concerns regarding solar deployment are not necessarily imminent in most countries. In the U.S. alone, studies have identified over eight billion square meters of rooftops suitable for solar panels by 2016, representing a potential solar capacity exceeding one terawatt. [311] Similarly, a Puerto Rico study (PR100) assessed 96% of buildings, estimating a potential capacity of 20.4 GW for residential rooftops alone. However, these estimates do not address the upgrades to utility control systems, energy storage capacity, and distribution systems that would be required to enable these rooftop solar potentials.

According to the Intergovernmental Panel on Climate Change (IPCC), solar PV ranks fourth in terms of life cycle CO_2 emissions among electricity generation technologies, emitting 41 g of CO_2 per kWh generated. [312] Most of these emissions occur during the early stages of the PV system's life cycle, especially during the energy-intensive production of PV components. However, with energy payback times ranging from one to four years, depending on the technology used, and a lifespan of 30 years, 87% to 97% of the energy generated by PV systems avoids pollution, greenhouse gases, and resource depletion.[313]

[311] U.S. Department of Energy. (2023, September 26). Solar Rooftop Potential. https://www.energy.gov/energysaver/consumer-guide-residential-solar-rooftop-potential

[312] Schlömer, S., Bruckner, T., Fulton, L., Hertwich, E., McKinnon, A., Perczyk, D., Roy, J., Schaeffer, R., Sims, R., Smith, P., & Wiser, R. (2014). Annex III: Technology-specific cost and performance parameters. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (pp. 1329-1354). *Cambridge University Press*. https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf

[313] National Renewable Energy Laboratory. (2004). PV FAQs. https://www.nrel.gov/docs/fy04osti/35489.pdf

Water consumption throughout the life cycle of PV systems is low and does not pose a significant threat. Hazardous substances only become a major environmental concern if modules are not recycled properly at the end of their life and end up in landfills, potentially contaminating soil and drinking water. Fortunately, over 85% of solar photovoltaic modules are made from materials with established recycling processes.[314]

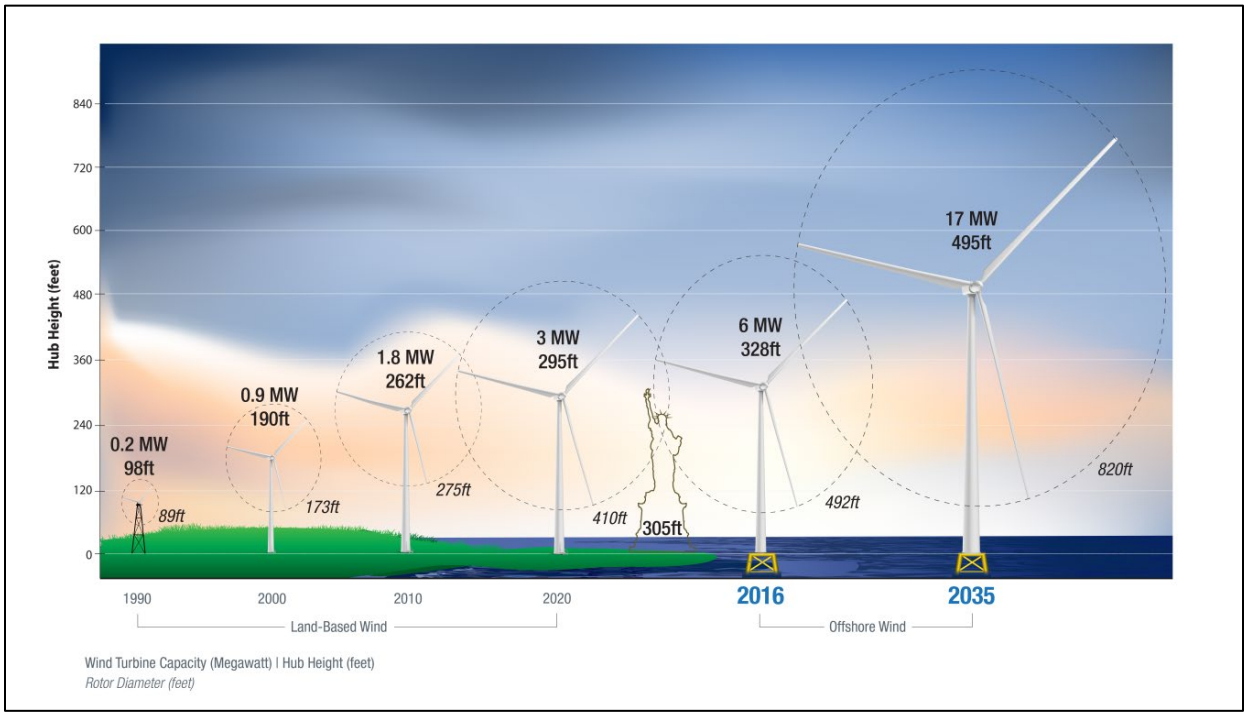
[314] U.S. Department of Energy. (n.d.). Beyond recycling: Reducing waste from solar modules before they're even made. https://www.energy.gov/eere/solar/articles/beyond-recycling-reducing-waste-solar-modules-theyre-even-made

26.0 *New Resources Option Report: Wind*

26.1 Description

Wind power has undergone remarkable advancements in the past few decades. Onshore wind system turbine hub height has increased by about 83% since 1998-1999, while for offshore wind turbines, the hub height has increased from 100 meters to about 150 meters. Also, the rotor diameter has increased over the years. In 2013, the rotors implemented in the United States were no more than 115 meters in diameter, while in 2023, the average rotor diameter used in new installations was over 133 meters. See Figure 86 for reference to how wind turbine size has changed over the years.[315]

Figure 86: Land-Based and Offshore Wind Turbine Size Change Over the Years



The United States has significantly increased its wind power capacity by 30% annually. Modern wind turbines effectively capture and convert the wind's kinetic energy into electricity, contributing substantially to the power grid. Wind energy is a byproduct of solar energy. The sun's uneven heating of the atmosphere and the Earth's surface, coupled with the Earth's varied topography, generates wind. Given the abundant wind, it is a sustainable resource as long as the sun continues warming our planet.[316]

Wind turbines harness the power of wind by converting its kinetic energy into electricity. The turbine's rotor blades, similar to airplane wings or helicopter blades, generate lift when wind flows over them. This lift force, stronger than the opposing drag, causes the rotor to spin. The rotor is connected to a generator, either

[315] Office of Energy Efficiency and Renewable Energy. (2024). Wind Turbines: the Bigger, the Better. *U.S. Department of Energy*. https://www.energy.gov/eere/articles/wind-turbines-bigger-better

[316] Wind Energy Technologies Office. (n.d.). Wind energy basics. *U.S. Department of Energy*. https://www.energy.gov/eere/wind/wind-energy-basics

directly or through a gearbox. This generator then transforms the mechanical rotation into electrical energy, which can be fed into the power grid. There are two types of wind turbines: the horizontal-axis turbines and the vertical-axis turbines. The most familiar type of wind turbine is the horizontal-axis wind turbine, which typically has three blades and is designed to face directly into the wind. The turbine is mounted on a tower, with the generator and other components in a streamlined container called a nacelle at the top of the tower. The base of the nacelle is the pivot point for adjusting the turbine's orientation to face the wind, allowing it to capture the wind energy efficiently. Vertical-axis wind turbines have a unique design that resembles an eggbeater. Unlike horizontal-axis turbines, these turbines can capture wind from any direction, eliminating the need for constant adjustments to face the wind. Figure 87 shows these two types of wind turbines.

Figure 87: Horizontal-Axis (Left) and Vertical-Axis (Right) Wind Turbines[317]



Wind turbines can be categorized by their installation location and grid connection. Land-based turbines, ranging from 100 kilowatts to several megawatts, are grouped into wind plants to supply bulk power to the grid. Offshore turbines that can be significantly larger are transported by sea and harness powerful ocean winds. Distributed wind turbines, including smaller residential and commercial units, are installed near the point of energy consumption. These turbines can be used in hybrid energy systems, which combine renewable sources such as solar and batteries, for grid-connected and off-grid systems.[318]

Wind power offers numerous advantages, including economic benefits, environmental sustainability, and community support. The industry provides well-paying jobs, with over 125,000 Americans employed in wind-related roles. As a domestic energy source, wind power contributes significantly to the U.S. economy, generating billions in tax revenue and investment. Wind turbines harness clean energy from the wind, avoiding harmful emissions and reducing carbon dioxide pollution. Wind projects also benefit local communities through tax payments and land lease revenue, supporting schools, reducing property taxes, and funding infrastructure improvements. Additionally, wind power is a cost-effective energy source well-suited for various landscapes, from agricultural areas to coastal regions, where abundant wind resources are often found.[319]

[317] Titan Worldwide Logistics, Heavy Haul 3PL. (2024, November 21). The two main types of wind turbines explained. *Titan Worldwide*. https://titanww.com/blog/types-of-wind-turbines/
[318] Office of Energy Efficiency and Renewable Energy. (n.d.). How do wind turbines work? *U.S. Department of Energy*. https://www.energy.gov/eere/wind/how-do-wind-turbines-work
[319] Office of Energy Efficiency and Renewable Energy. (n.d.). Advantages and challenges of wind energy. *U.S. Department of Energy*. https://www.energy.gov/eere/wind/advantages-and-challenges-wind-energy

Wind power, while a promising renewable energy source, faces several challenges. Location directly impacts cost competitiveness, as wind projects may not be economically viable in areas with insufficient wind resources. However, ongoing technological advancements and research are helping to reduce costs. Additionally, the remote locations of many ideal wind sites necessitate significant infrastructure investments, such as upgrading transmission networks, to connect wind farms to urban areas. While wind power has a lower environmental impact than traditional power plants, concerns remain regarding noise pollution and aesthetics. Furthermore, wind turbines can potentially impact local wildlife, and ongoing research is focused on minimizing these interactions through technological innovations, careful site selection, and environmental studies.

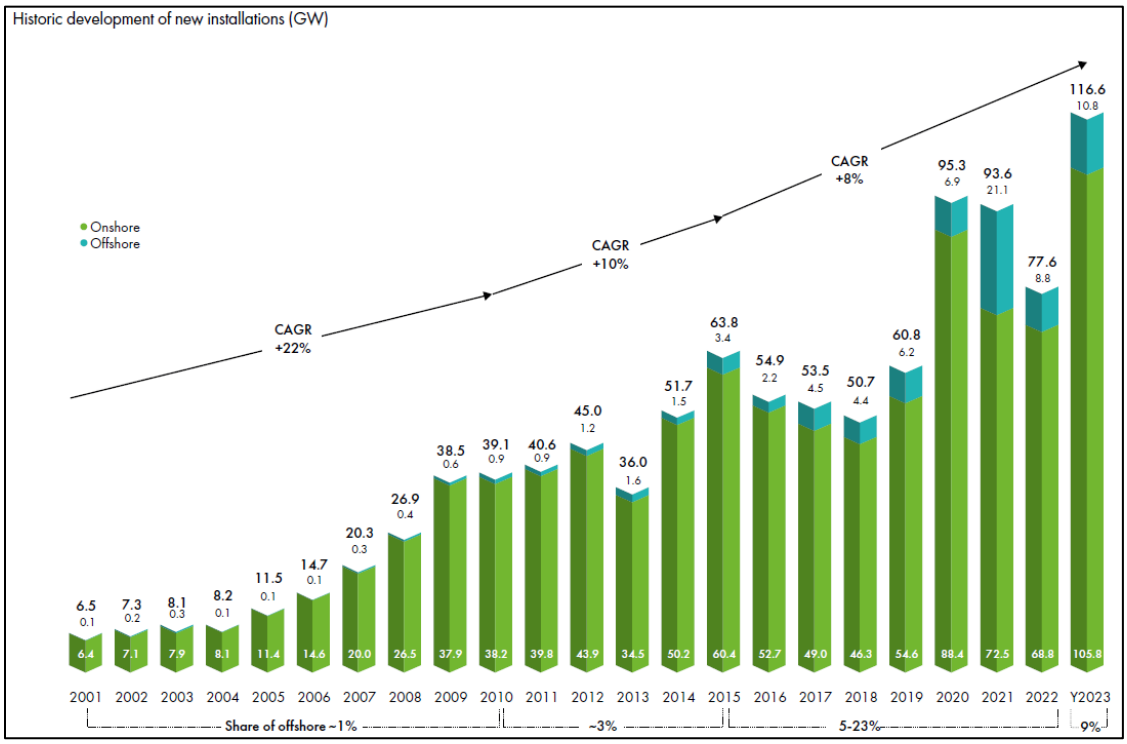
Act 17, passed in 2019, established Puerto Rico's commitment to achieving 100% renewable energy by 2050. With significant federal funding available, studies by the National Renewable Energy Laboratory (NREL) have explored potential pathways to achieve this goal. One such study, preceding the PR100 initiative, assessed wind energy potential in Puerto Rico, finding significant technical capacity for land-based (6.81 GW) and offshore (46.85 GW) wind turbines. Cost projections indicate that land-based wind energy will become more cost-competitive over time, with the levelized cost of energy (LCOE) decreasing from $92/MWh in 2023 to $65/MWh by 2035. Offshore wind has higher LCOE but also offers substantial potential. Land-based and offshore wind projects have varying net capacity factors, with land-based projects averaging 0.42 and offshore projects averaging 0.38. These findings provide valuable insights into the planning process for Puerto Rico's renewable energy future.[320]

Wind power has become the leading renewable energy source in the United States, with capacity tripling in the past decade. Total installations of 117 GW in 2023 represent a 50% year-on-year increase from 2022. Figure 88 shows the historical development of new installations globally.[321]

[320] National Renewable Energy Laboratory. (2024). Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100). https://pr100.gov/results/renewable-resources-results

[321] Lee, J. & Zhao, R. (2024). Global Wind Report 2024. *Global Wind Energy Council*, (April 16). https://gwec.net/global-wind-report-2024/#download

Figure 88: Historical Development of New Installations (GW)

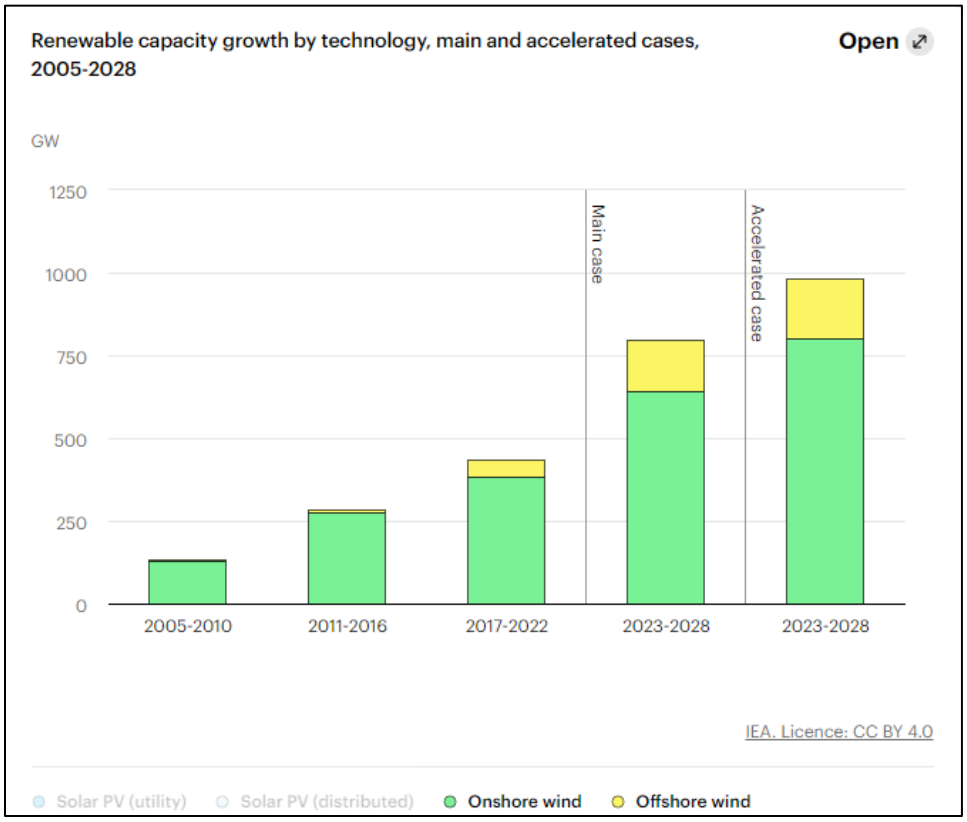


26.2 Technology Maturity

As of 2022, 93% of the wind installed capacity was onshore systems, while the remaining 7% was on offshore wind farms. Figure 89 shows the capacity growth of both onshore and offshore wind systems since 2005. Onshore wind, a more developed technology, is deployed in approximately 115 countries. Offshore wind is still in the early stages of operation and expansion in only 20 countries. Offshore wind development is expected to grow as more countries plan or implement their initial offshore wind farms. As of 2022, offshore technology delivered around 18% of the total wind capacity growth.[322]

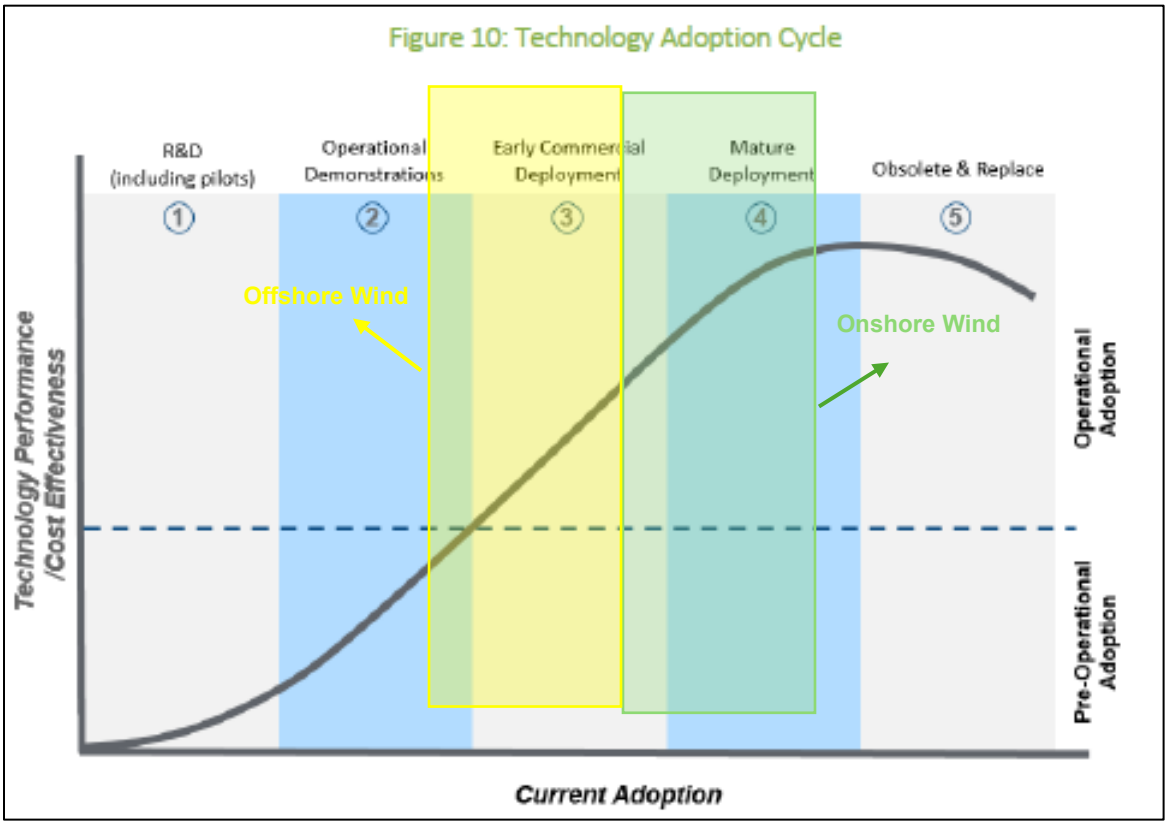
[322] International Energy Agency (IEA). (n.d.). Wind. https://www.iea.org/energy-system/renewables/wind

Figure 89: Wind Renewable Capacity Growth Since 2005



Considering the current adoption of these technologies, the two are in different stages of the technology adoption cycle. Of the four technology maturity categories, onshore wind technology, using a proven design of a horizontal nacelle and a three-bladed turbine on a tower, is in the fourth stage (i.e., Mature Development), while offshore technology, using larger scale versions of the three-bladed design is in the third stage (i.e., Early Commercial Development). There are also many innovative and alternative designs for capturing wind energy that have either already been discarded during their early development stages or are still progressing through the earlier stages of technological maturity.

Figure 90: Technology Maturity Adoption Stage



Regarding the market trends, China continues to lead the way with wind capacity additions, adding 37 GW in 2022. The European Union is accelerating wind deployment due to the energy crisis, with 13 GW added in 2022. The United States has introduced significant new funding for wind power through the Inflation Reduction Act, and the United Kingdom has installed more offshore wind capacity than the rest of the world combined (excluding China). These trends, driven by policy initiatives and market conditions, indicate a strong global momentum towards wind energy adoption.[323]

Puerto Rico currently has two commercial onshore wind projects in operation. The first one is Pattern Energy, located in Santa Isabel. It has 44 wind turbines and a total capacity of 95 MW. The Pattern Energy project began operations in 2012 and produces sufficient energy to address the needs of approximately 80,000 residents on the Island.[324] The second project in operation is Punta Lima, located in Naguabo, which has 13 turbines and a total capacity of 26 MW. The project initiated operations in 2013. After Hurricane María severely damaged it, the site was rebuilt and resumed operations in early 2024.

26.3 Cost

Under the PR100 report, NREL conducted a study to assess wind energy costs and technical potential in Puerto Rico to provide stakeholders with a better understanding of wind resources and guidance for future planning processes. NREL modified the cost models to reflect Puerto Rico's unique features and

[323] International Energy Agency (IEA). (n.d.). Wind. https://www.iea.org/energy-system/renewables/windd
[324] Pattern Energy. (2024, April 8). Santa Isabel Wind. https://patternenergy.com/projects/santa-isabel-wind/

costs, and defined wind energy technology pathways to project costs from 2023 to 2035 for onshore wind systems and from 2030 to 2035 for offshore wind systems. The key findings from this modeling work are summarized in Table 59.[325]

Table 59: Summary of Energy Production Costs for Onshore and Offshore Wind Systems

Technology	Land Use Variation	Year	Mean LCOE ($/MWh)	Minimum LCOE ($/MWh)	Maximum LCOE ($/MWh)	Mean NCF (5)
Onshore wind	Less Land	2023	$92	$51	$292	26%
	Less Land	2030	$85	$47	$268	26%
	Less Land	2035	$65	$41	$187	42%
	More Land	2023	$84	$45	$244	26%
	More Land	2030	$76	$41	$223	26%
	More Land	2035	$58	$35	$156	42%
Offshore wind	N/A	2030	$137	$82	$156	36%
	N/A	2035	$118	$74	$130	38%

26.3.1 Onshore Wind Systems

The expected LCOE for the less land variation in 2023 ranges from approximately $51/MWh to $292/MWh (5.8 cents/kWh to 29.2 cents/kWh), with a mean of $92/MWh. By 2035, the LCOE values decline to a range of $41/MWh–$187/MWh, with a mean of $65/MWh.[9] Under the more land variation, the expected LCOE in 2023 ranges from approximately $45/MWh to $244/MWh, with a mean of $84/MWh. By 2035, the LCOE ranges from $35/MWh to $156/MWh, with a mean of $58/MWh.[10]

26.3.2 Offshore Wind Systems

Expected LCOE for offshore wind in 2030 ranges from approximately $82/MWh to $414/MWh, with a mean of $137/MWh. By 2035, the LCOE values decline to a range of $74/MWh–$350/MWh, with a mean of $118/MWh. [10]

26.4 Supply-Chain

The wind energy industry in the United States relies on a complex supply chain involving numerous components and suppliers. As one of the few countries capable of producing all significant wind turbine components, the U.S. plays a key role in the global wind energy market. Understanding this supply chain is critical for successfully developing wind energy projects.

The domestic supply chain for land-based wind energy has been well established and reasonably stable over the past five years. The production capacity is between seven gigawatts (GW) and 10 GW for blades and towers, and between 10 GW and 15 GW for nacelle assembly. However, there has been limited offshore wind deployment in the U.S., with international supply chains already developed for major components, installation vessels, and engineering expertise. Recent efforts, led by the Biden Administration under Executive Order 14008, establish a target to deploy 30 GW of offshore wind in the

[325] National Renewable Energy Laboratory. (2024). Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100). https://pr100.gov/results/renewable-resources-results

United States by 2030.[326] This presents an opportunity to build domestic supply chain capacity, reducing risk and cost while offering local economic benefits.

Wind power plants consist of five primary components:

- **Towers:** Primarily made of steel, with some concrete and hybrid designs. Domestic tower manufacturing capacity reached 10 GW in 2020,[327] with year-to-year variation in sourcing imported towers, mainly from Canada (20%) and India (18%), supplying the largest quantities in 2020.[328]
- **Blades:** Domestic capacity was approximately 10 GW in 2019, but some facilities have closed, reducing capacity to six GW. Plans have been announced to open an offshore wind blade production facility in Virginia.[329] In 2019, China (20%), Brazil (14%), Mexico (14%), India (14%), and Spain (11%) were the primary sources of imported blades and hubs.
- **Nacelles:** These house the powertrain and other components. In 2020, domestic nacelle assembly accounted for more than 85% of the U.S. market, with a capacity of around 15 GW. The primary suppliers of wind-powered generating sets and parts, including nacelles, were India (26%), Denmark (15%), Germany (15%), Brazil (10%), and Spain (8%) in 2020.
- **Foundations:** Land-based foundations are mostly concrete, while offshore foundations are primarily steel. By 2035, most U.S. offshore turbines on the Atlantic coast will likely use monopile or jacket foundations, with some using gravity-based designs.[330]
- **Grid interconnection cabling and equipment:** Cables linking turbines to substations are made of copper or aluminum, with subsea cables requiring extra protection. Substations and components like switchgear and transformers are sourced from domestic and foreign manufacturers.

Domestic content is relatively strong for significant components of land-based wind plants, such as towers and blades, as shown in Figure 91. Although there is no domestic offshore wind supply chain capacity, the U.S. announced several manufacturing facilities for critical offshore wind energy system components in 2024. Most of these manufacturing facilities are concentrated in the Northern Atlantic, near the shipyard, and in the development of offshore areas. The domestic supply chain in 2020 could produce 10-15 GW/year for each primary land-based turbine component (towers, blades, and nacelles).[331]

[326] The White House. (2021). Biden Administration Jumpstarts Offshore Wind Energy Projects to Create Jobs. https://www.whitehouse.gov/briefing-room/statements-releases/2021/03/29/fact-sheet-biden-administration-jumpstarts-offshore-wind-energy-projects-to-create-jobs/

[327] Wiser, R., Bolinger, M., Hoen, B., Millstein, D., Rand, J., Barbose, G., Darghouth, N., Gorman, W., Jeong, S., Mills, A. & Paulos, B. (2021). Land-Based Wind Market Report: 2021 Edition. DOE/GO-102021-5611. *U.S. Department of Energy*. https://live-lbl-eta-publications.pantheonsite.io/sites/default/files/land-based_wind_market_report_2021_edition_final.pdf

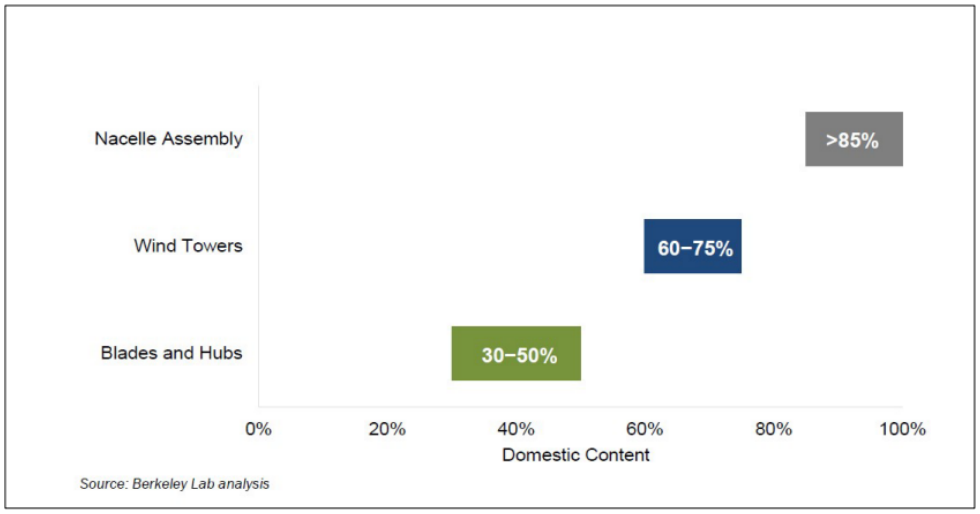
[328] Office of Energy Efficiency and Renewable Energy. (2022). Wind energy supply chain deep dive assessment. *U.S. Department of Energy*. https://www.energy.gov/sites/default/files/2022-02/Wind%20Energy%20Supply%20Chain%20Report%20-%20Final.pdf

[329] Whitlock, R. (2021). Siemens Gamesa solidifies offshore presence in US with Virginia blade facility. *Renewable Energy Magazine*, (October 29). https://www.renewableenergymagazine.com/wind/siemens-gamesa-solidifies-offshore-presence-in-us-20211029

[330] U.S. Department of Energy. (2022, February 24). Wind Energy Supply Chain Deep Dive Assessment. https://www.energy.gov/sites/default/files/2022-02/wind-energy-supply-chain-deep-dive-assessment.pdf

[331] Wiser, R., Bolinger, M., Hoen, B., Millstein, D., Rand, J., Barbose, G., Darghouth, N., Gorman, W., Jeong, S., Mills, A. & Paulos, B. (2021). Land-Based Wind Market Report: 2021 Edition. DOE/GO-102021-5611. *U.S. Department of Energy*. https://live-lbl-eta-publications.pantheonsite.io/sites/default/files/land-based_wind_market_report_2021_edition_final.pdf

Figure 91: Department of Energy's (DOE) Supply Chain Deep Dive Assessment[332]



The demand for raw materials can be met completely (e.g., concrete) or partially (e.g., iron, copper, aluminum) with domestic production for wind turbine manufacturing. Some materials, such as rare earth elements, alloying elements, and balsa wood, cannot be produced domestically. While rare earth elements are required for magnets used in permanent magnet generators, they are not mined in the United States sufficiently to meet the demand for offshore wind drivetrains and other uses. Global production is concentrated in China, where the processing of heavy rare earth elements—including dysprosium and terbium—takes place.[333] The production of steel alloys used in wind turbines requires elements, including chromium, molybdenum, manganese, nickel, and niobium, that the United States produces in limited quantities or not at all.

Developing the wind energy sector in the United States presents significant opportunities and complex challenges. As industry evolves, offshore and onshore wind projects offer substantial economic growth and technological advancement potential. However, realizing these benefits requires addressing several key obstacles and leveraging strategic opportunities across various aspects of the supply chain.

Establishing a domestic offshore wind supply chain is a major opportunity. The U.S. Administration's national offshore wind target represents a potential annual economic injection of $942 million to $3,800 million, with significant gross domestic product (GDP) impacts depending on the level of domestic content.[334] The production of nacelles, blades, and substructures, essential for offshore wind projects, presents substantial job creation potential. For instance, metal fabrication for towers and substructures and the manufacturing of blades, such as Siemens Gamesa's planned new facility in Virginia (Siemens Gamesa Renewable Energy 2021), offer considerable economic and employment opportunities.

[332] Whitlock, R. (2021). Siemens Gamesa solidifies offshore presence in US with Virginia blade facility. *Renewable Energy Magazine*, (October 29). https://www.renewableenergymagazine.com/wind/siemens-gamesa-solidifies-offshore-presence-in-us-20211029

[333] AMO. (2020, April 21). *Critical Materials Rare Earths Supply Chain: A Situational White Paper.*

[334] Shields, M., Oteri, F., Stefek, J., Moser, A., Marsh, R., Rouxel, N., Diaz, K., & Molinero, J. (2022). 30 GW by 2030: A Supply Chain Roadmap for Offshore Wind in the United States. Part 1: The Demand for a Domestic Supply Chain. *National Renewable Energy Laboratory.*

Additionally, existing domestic electrical cable manufacturers can benefit from the anticipated annual demand of 980 miles of cable required for offshore wind buildout between 2023 and 2030.[335]

For onshore wind systems, maintaining and expanding domestic production capabilities is crucial. Recent closures of blade production facilities have reduced domestic capacity by nearly 40%.[336] Investment in research and development to advance blade technologies and retool manufacturing facilities is vital to prevent further offshoring. Furthermore, increasing domestic production of towers and blades can counteract recent declines in manufacturing capacity and meet growing demand.

The development of offshore wind logistics and infrastructure also presents significant opportunities. Building domestic capabilities for turbine installation vessels and upgrading ports is critical to addressing logistical challenges and supporting offshore wind expansion. Current projections indicate that meeting the Administration's 30 GW by 2030 target will require substantial port upgrades, with potential costs ranging from $375 million to $3.1 billion, depending on the scale of development. These investments will create jobs and help navigate regulatory complexities, such as the Jones Act. Expanding domestic manufacturing of composite materials, such as carbon fiber and fiberglass, is essential due to increasing demand. Analysts project that demand for carbon fiber in wind turbines will triple by 2027.[337] Investing in research and development to advance composite materials and manufacturing techniques can strengthen the U.S. supply chain and reduce reliance on foreign sources.

However, several challenges must be addressed to support the growth of the wind energy sector. Adapting existing land-based wind suppliers to offshore wind requirements is challenging due to differences in turbine size and scale and geographic and regulatory barriers (Shields et al., 2022). Collaborative solutions across states are needed to optimize supply chain development. Another critical challenge is training and developing a qualified workforce. Expanding and offshore wind sectors will require comprehensive education and training programs for roles in design, installation, maintenance, and manufacturing. Projections suggest that offshore wind could support between 10,500 and 42,500 domestic jobs by 2030, necessitating significant investment in workforce development.

Logistical issues related to onshore wind projects also pose challenges. The increasing size of wind components strains existing transportation infrastructure, and addressing permitting issues is necessary to accommodate larger blades, towers, and nacelles. The lengths of turbine blades are constrained by the ability to transport the blades on highways and the ability to navigate turns and overpasses during the transport.

Fostering U.S. competitiveness in subcomponent manufacturing is crucial. Enhancing domestic capabilities for large castings, bearings, and semiconductors can reduce reliance on international suppliers and drive economic development. For instance, the U.S. has lost market share in producing forged rings and large castings to foreign producers,[338] highlighting the need for innovation and investment in these areas.

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[335] Lantz, E., Barter, G., Gilman, P., Keyser, D., Mai, T., Marquis, M., Mowers, M., Shields, M., Spitsen, P., & Stefek, J. (2021). Power sector, supply chain, jobs, and emissions implications of 30 gigawatts of offshore wind power by 2030. *National Renewable Energy Laboratory*. [NREL/TP-5000-80031, 1814139]. https://doi.org/10.2172/1814139

[336] Office of Energy Efficiency and Renewable Energy. (2022). Wind energy supply chain deep dive assessment. *U.S. Department of Energy*. https://www.energy.gov/sites/default/files/2022-02/Wind%20Energy%20Supply%20Chain%20Report%20-%20Final.pdf

[337] Barla, S. (2021). Global wind turbine supply chain trends 2021. 81.

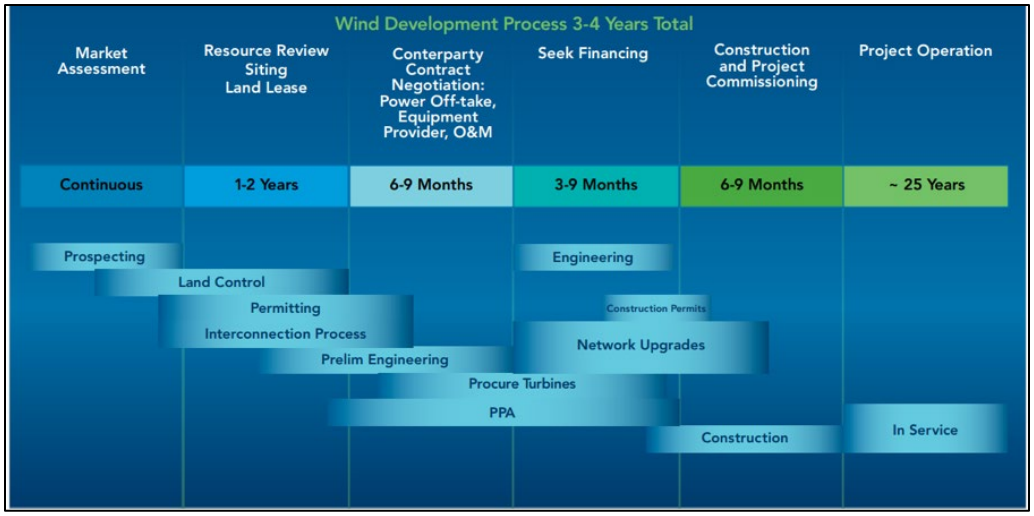
[338] Fullenkamp, P.H. & Holody, D.S. (2014). U.S. Wind Energy Manufacturing and Supply Chain: A Competitiveness Analysis. *U.S. Department of Energy*. DOE-GLWN-0006102, 1156678. https://www.osti.gov/servlets/purl/1156678

Finally, addressing challenges related to processed materials—such as steel, rare earth elements, and semiconductors—is crucial. Innovations in material production and processing, including green steel, alternatives to rare earth elements, and a boost in domestic production,[339] are necessary to mitigate current supply chain vulnerabilities and reduce environmental impacts. Overall, the wind energy sector offers significant potential for growth, but realizing this potential requires overcoming substantial challenges through strategic investment and innovation.

26.5 Construction and Development

The development and construction of wind projects involve significant risks, uncertainties, and resource expenditure. Project developers typically initiate and manage these projects, often selling them before or after completion. Key activities include site selection, landowner negotiations, permitting, grid connection, and securing financing. The engineering, procurement, and construction (EPC) contractor is responsible for engineering, procurement, and construction, while the project developer contracts with the power purchaser. Figure 92 shows a timeline breakdown of the development of a wind project, which has a total duration of 3-4 years.[340]

Figure 92. Timeline of the Development of a Wind Power Project[341]



Developing a wind project involves several key stages, including land acquisition, wind resource analysis, permitting, transmission and interconnection, financing, environmental review, and EPC. Land acquisition can be through easement, lease, or fee title, with federal land requiring specific permits. Wind resource analysis determines project viability and informs negotiations with power off-takers. Permitting involves obtaining approvals at the local, state, and federal levels, with varying requirements across jurisdictions. Transmission and interconnection are crucial for connecting wind projects to the grid, often requiring new transmission lines and regulatory agency approval. Financing is essential for project development, with

[339] Blank, T.K. (2019). The disruptive potential of green steel. *Rocky Mountain Institute*.
[340] Lawrence Berkeley National Laboratory. (2018). Wind project development & EPC — Descriptive information. *Energy I-SPARK*, (October 1). ei-spark.lbl.gov
[341] See: https://windexchange.energy.gov/files/pdfs/land-based-economic-guide.pdf

power purchase agreements playing a key role in securing investment. Environmental review assesses potential impacts on wildlife, cultural resources, and landscapes.[342]

Researchers indicate that the average land area required for an onshore wind plant is 0.34 km²/MW (85.24 acres/MW). For offshore wind plants, they proposed a range of values between 0.20 and 0.60 km²/MW (49.4 to 148.2 acres/MW) for projects along the U.S. East Coast.[343] These spatial requirements are critical during the site selection and planning stages, as they directly impact land use efficiency, environmental considerations, and community acceptance.

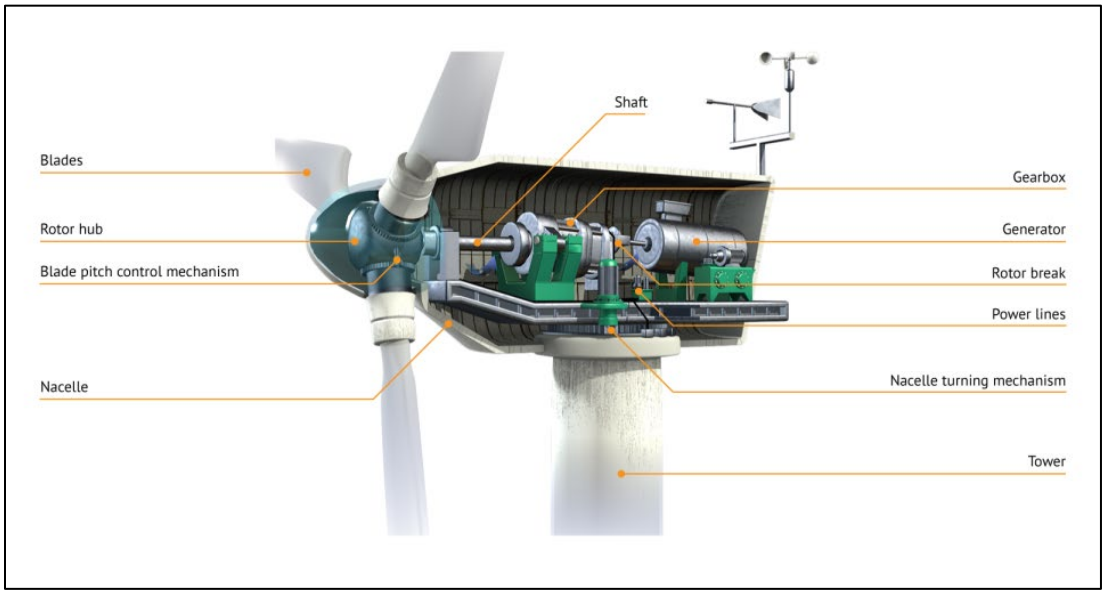
Wind energy, while a promising renewable energy source, faces several challenges. The initial capital investment for constructing wind farms can be substantial, with costs ranging from tens to hundreds of millions of dollars. Additionally, wind turbines can pose risks to wildlife, particularly birds and bats, due to blade collisions. Aesthetic concerns and noise pollution are also potential issues for nearby communities. The intermittent nature of wind energy, dependent on weather conditions, can require backup energy sources or storage solutions. Offshore wind farms face higher installation and maintenance costs due to the need for specialized ships, weather dependency, and more complex installation processes. Political and community opposition can also hinder wind project development due to concerns about property values, environmental impacts, and changes to the landscape. Addressing these challenges is essential for successfully integrating wind energy into the power grid.[344]

26.6 Operation

Wind power plants consist of wind turbines strategically located in favorable wind conditions. Each turbine measures the wind speed and direction, adjusting blade angles to optimize the capture of wind energy and convert it into mechanical energy, which is then used to drive a generator and produce electricity. The generated electricity is transmitted through power lines to substations, where it is transformed and injected into the grid. Wind turbines typically comprise a tower, nacelle, rotor, and blades. The tower supports the turbine structure, while the nacelle houses the generator, gearbox (if applicable), and other components. The rotor, consisting of blades and a hub, captures wind energy and converts it into rotational motion.[345] The generator then transforms this mechanical energy into electricity. Figure 93 shows a breakdown of these components.

[342] Lawrence Berkeley National Laboratory. (2018). Wind project development & EPC — Descriptive information. *Energy I-SPARK*, (October 1). ei-spark.lbl.gov
[343] U.S. Department of Energy. (n.d.). Wind Vision: A New Era for Wind Power in the United States. https://www.energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf
[344] Looper, L. (2024). Are there any risks associated with the production of wind energy? *HowStuffWorks*, (September 5). https://science.howstuffworks.com/environmental/energy/risks-associated-wind-energy.htm
[345] U.S. Department of Energy. (n.d.). How a wind turbine works - Text version. version#:~:text=A%20wind%20turbine%20turns%20wind%20energy%20into%20electricity%20using%20the

Figure 93: Components of a Wind Turbine[346]



Onshore and offshore wind system turbines have distinct characteristics. Offshore turbines are generally larger and have longer blades to capture stronger ocean winds. Also, they often use direct-drive technology, eliminating the need for a gearbox. This technology works by connecting the rotor directly to the generator, avoiding gearbox issues of reliability and efficiency. Additionally, the transportation and installation of offshore turbines are more complex due to marine conditions.[347] Wind turbine maintenance is essential for ensuring optimal performance and minimizing costs. Preventive maintenance, performed at regular intervals, and predictive maintenance, based on condition monitoring, are key strategies. An operation and maintenance (O&M) agreement with a professional contractor is recommended, covering scheduled maintenance (typically performed every six months to two years), emergency plans, spare parts, and response times. As turbines age, maintenance costs may increase due to component replacement. Factors to be considered in an O&M agreement include cost, frequency, safety plans, maintenance checklists, spare parts, unscheduled maintenance procedures, training requirements, and component replacement planning.[348] Table 60 shows an example of the essential maintenance tasks for wind turbines.[349]

Table 60: Maintenance Action Tasks for Wind Turbine Components

Component	Action
Blade	Inspect for damage
	Monitor erosion

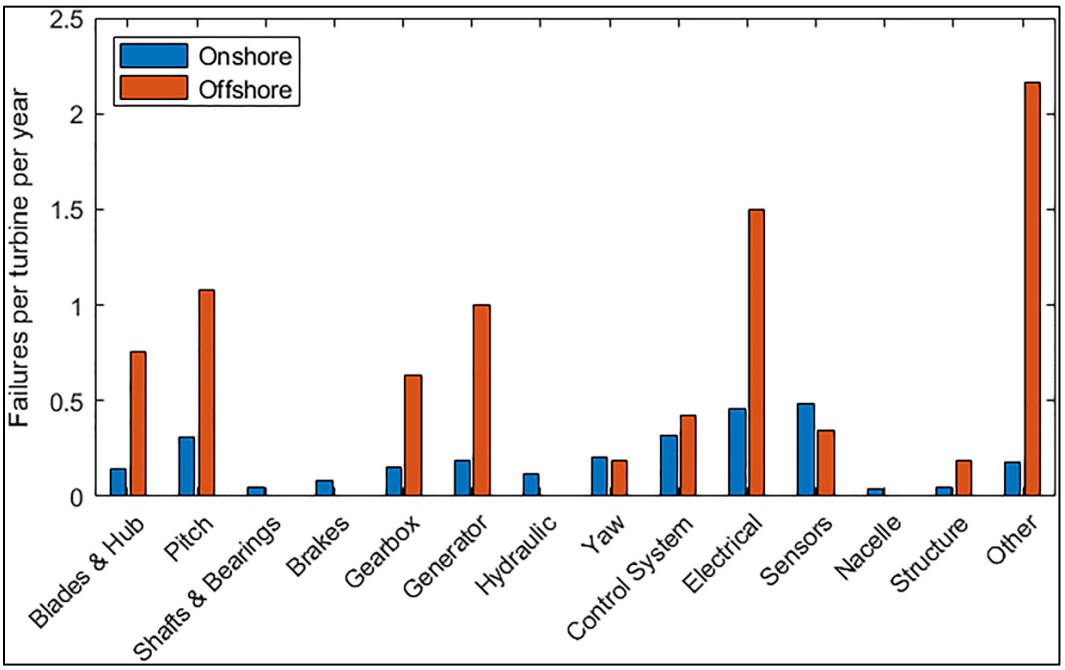
[346] See: https://www.energyencyclopedia.com/en/free-downloads/images/generator-room-of-a-wind-turbine-72
[347] U.S. Department of Energy. (n.d.). How a wind turbine works - Text version. https://www.energy.gov/eere/wind/how-wind-turbine-works-text-version#:~:text=A%20wind%20turbine%20turns%20wind%20energy%20into%20electricity%20using%20the
[348] Pacific Northwest National Laboratory (PNNL). (n.d.). O&M best practices for on-site wind turbines. https://www.pnnl.gov/projects/om-best-practices/onsite-wind-turbines
[349] Muscad, O. (2024). How to conduct wind turbine maintenance to ensure smooth turbine operations. *Datamyte*, (August 20). https://datamyte.com/blog/wind-turbine-maintenance/#Q3_How_often_do_wind_turbines_require_maintenance

Component	Action
Gearbox	Oil analysis
	Vibration monitoring
Generator	Thermal imaging
	Insulation testing
Bearing	Lubrication
	Temperature monitoring
Rotor	Bird strike inspections
	Foreign object debris removal
Electrical system	Circuit breaker testing
	Grounding checks
Tower	Foundation inspection
	Corrosion protection
Nacelle	Corrosion inspection
	Ventilation checks

Poor maintenance and the environment could lead to different failures in different parts of the wind turbines. There are variations in component failure rates between onshore and offshore wind turbines. As shown in Figure 94, the failure rate for offshore wind turbine components is approximately double that of onshore wind turbine components.[350] In terms of failure rates, this might indicate that onshore wind turbines could be more reliable than offshore wind turbines.

[350] Dao, C., Kazemtabrizi, B. & Crabtree, C. (2019). Wind turbine reliability data review and impacts on levelized cost of energy. *Wind Energy*, 22(12), 1848–1871. https://doi.org/10.1002/we.2404

Figure 94: Failures per Turbine per Year[351]



26.7 Sustainability

The life cycle of wind energy can be divided into several key stages: manufacturing, transportation, installation, operation, maintenance, and decommissioning. Each phase contributes to the overall environmental impact and cost of wind power. For onshore and offshore wind farms, the most carbon-intensive phase is manufacturing turbine components, such as blades, towers, and foundations, which require significant amounts of steel, fiberglass, and concrete. The transportation and installation stages also add to the carbon footprint, especially for offshore projects, where logistical challenges increase energy use. However, once operational, wind turbines generate electricity without direct emissions for 20 to 30 years, depending on the site. Decommissioning involves dismantling the turbines, and current efforts are focused on improving the recyclability of turbine blades and other materials to minimize waste.

According to the Intergovernmental Panel on Climate Change (IPCC), onshore wind ranks among the lowest in life cycle CO_2 emissions, releasing just 11 g of CO_2 per kWh generated. In comparison, offshore wind emits slightly more at 12 g of CO_2 per kWh. Like solar photovoltaic (PV), most of these emissions occur during the manufacturing, transportation, and installation phases, particularly in producing wind turbine components, such as steel for towers and concrete for foundations. However, with an energy payback time of less than one year for onshore wind and slightly longer for offshore installations, wind energy systems can operate for 20 to 30 years, meaning over 95% of the energy generated during their lifespan results in net-zero emissions. Furthermore, advances in recycling turbine blades and reducing reliance on carbon-intensive materials continue to lower the overall carbon footprint of wind energy

[351] See: https://onlinelibrary.wiley.com/doi/full/10.1002/we.2404

technology—this positions wind power as one of the most environmentally sustainable options for large-scale electricity generation.[352]

Wind energy is making significant strides towards a more sustainable future. While the industry has achieved high levels of recyclability for many turbine components, challenges remain, particularly in recycling fiberglass and carbon fiber composites used in blades. Approximately 80-90% of a wind turbine's mass, consisting primarily of metals like steel, aluminum, and copper, is readily recyclable, creating a robust market for these materials in a circular economy. However, fiberglass and carbon fiber composites, comprising about 6% of a turbine's mass, present recycling challenges due to the epoxy resins used in their construction.[353]

Researchers are actively exploring innovative solutions to address this issue. They are studying thermoplastic resins, which allow for easier recycling at the end of a blade's lifespan, as alternatives to traditional epoxy resins. Additionally, research on 3D printing techniques is underway to produce blades made from inherently recyclable materials. Mechanical, thermal, and chemical recycling processes are also under development to enable the recycling of existing composite blades. Although recycling rare earth elements used in permanent magnet generators is still in its early stages, the significant quantities of these magnets in wind turbines present future recycling potential. Experts anticipate this potential will increase, particularly after 2030, when many turbines end their operational life.

Wind energy's long-term operational phase largely determines its economic and environmental benefits. With less than a year of energy payback times for onshore and slightly longer for offshore wind farms, most of their lifespan is spent generating clean energy. Advances in technology have also significantly reduced the LCOE, making wind one of the most cost-effective forms of renewable energy. Onshore wind power experienced a 61.6% reduction in LCOE from 2010 to 2021, while offshore wind saw a 53.4% decrease.[354] The lower O&M costs for onshore wind make it more economical, but offshore wind offers higher energy yields due to more potent and consistent winds at sea. However, it requires higher upfront capital and installation costs.

In conclusion, wind energy is a key player in the global shift towards sustainable electricity generation. Despite the carbon-intensive nature of the manufacturing and installation stages, the long-term operational benefits, coupled with advancements in recyclability and material efficiency, significantly reduce the overall environmental impact. With less than a year energy payback times and continued improvements in technology and cost reduction, wind power remains one of the most viable and eco-friendly solutions for large-scale energy production. As the industry continues to innovate in recycling and resource conservation, wind energy is well-positioned to drive the future of clean, renewable energy.

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[352] Bruckner, T., Fulton, L., Hertwich, E., McKinnon, A., Perczyk, D., Roy, J., Schaeffer, R., Schlomer, S., Sims, R., Smith, P. & Wiser, R. (2014). 2014: Annex III: Technology-specific cost and performance parameters. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. *Cambridge University Press*, Cambridge, United Kingdom and New York, NY, USA. https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf

[353] U.S. Department of Energy. (2022). Wind Energy Supply Chain Deep Dive Assessment: Response to Executive Order 14017, "America's Supply Chains". https://www.energy.gov/sites/default/files/2022-02/Wind%20Energy%20Supply%20Chain%20Report%20-%20Final.pdf

[354] Liu, J., Kazemtabrizi, B., & Crabtree, C. (2023). Life cycle cost modelling and economic analysis of wind power: A state of art review. *Energy Conversion and Management*, 277, 116628. https://www.sciencedirect.com/science/article/pii/S0196890422014066

27.0 *New Resource Option: Municipal Waste-to-Energy*

27.1 Description

Municipal waste-to-energy refers to various technologies and methodologies that take different waste products (called municipal solid waste or MSW) and produce electricity to be injected into the electric grid. MSW includes biogenic materials (such as paper, wood, and vegetative trimmings), non-biogenic combustible materials, such as petroleum-based synthetic products, and noncombustible materials, such as glass and metals. This generation of technology has existed since the late 19th century, with more modern waste-to-energy (WTE) facilities becoming popular after the Clean Air Act in 1970. There are hundreds of facilities around the world generating electricity from MSW (see Technology Maturity section). It is an effective method to minimize the reliance on landfills as waste production increases, since the volume of MSW is reduced by 87% during the WTE process. [355]

Common methods to convert MSW into electricity include incineration, pyrolysis/gasification, and anaerobic digestion. Incineration via mass burning was the earliest WTE system principle and remains the most common type in the United States, in which unprocessed MSW is burned in an incinerator to boil water and generate electricity via a steam turbine (see Figure 95). Modern facilities utilize extensive air pollution control systems. Along with the boiler, this process generates ash, a byproduct that the industry can reuse. Some facilities can pre-process waste to remove non-combustible components and produce refuse-derived fuel. This also lessens the amount of air required for combustion, thus decreasing the cost of the air pollution control systems' operation.[356] The average energy recovery of incineration facilities is 550 kWh per ton of municipal waste.[357]

Pyrolysis of MSW involves subjecting the waste to extremely high heat using a thermochemical process to degrade the chemical bonds. Depending on the temperature and composition of MSW, this process produces a solid (tar), liquid (pyrolytic oil), or non-condensable gaseous product.[358] This process produces almost no greenhouse gas (GHG) emissions and several valuable fuels. However, the inconsistent composition of MSW makes the results of pyrolysis inconsistent and thus unreliable at scale without strict processing and sorting.

Another process, anaerobic digestion, requires sorting biotic/organic material before conversion. Operators place the material into a heated tank, where microorganisms decompose and release gas, which they collect. Due to the complex nature of the anaerobic digestion process and the ample space required for the plant, the popularity of these systems has remained limited.[359]

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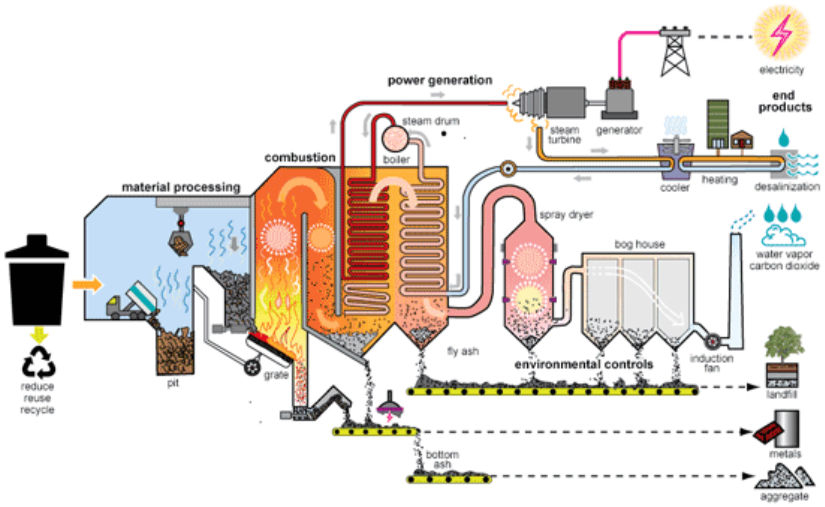
[355] U.S. Energy Information Administration (EIA). (2024, October 29). Waste-to-energy (municipal solid waste). https://www.eia.gov/

[356] Traven, Luka. (2023). Sustainable Energy Generation from Municipal Solid Waste: A Brief Overview of Existing Technologies. *Case Studies in Chemical and Environmental Engineering*, vol. 8, (September), p. 100491. https://doi.org/10.1016/j.cscee.2023.100491.

357 U.S. Environmental Protection Agency. (2024, December 28). Energy Recovery from the Combustion of Municipal Solid Waste (MSW). https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw

[358] Gerasimov, G. (2008). Pyrolytic Processing of Municipal Solid Waste. *Thermopedia*. https://doi.org/10.1615/thermopedia.010248.

Figure 95: Diagram of a Mass-Burn Waste-to-Energy Facility[360]



While these technologies have existed for decades, they face several challenges regarding adoption in utility-scale applications. For one, electricity generated from WTE facilities tends to be more expensive than other widely available generation sources (see MSW Costs section). WTE facilities' high costs and deployment limitations, due to siting requirements and permitting hurdles, make them less attractive in competitive energy markets. There is also an adjacent and robust market for MSW facilities for heating and various industrial processes. Also, because WTE is not classified as a renewable energy source, these facilities often lack policy backing and eligibility for financial incentives.[361] However, with Puerto Rico having an excess of MSW and the current landfills being at or beyond capacity and noncompliant with Environmental Protection Agency (EPA) standards, the potential for WTE provides a variety of practical upsides.

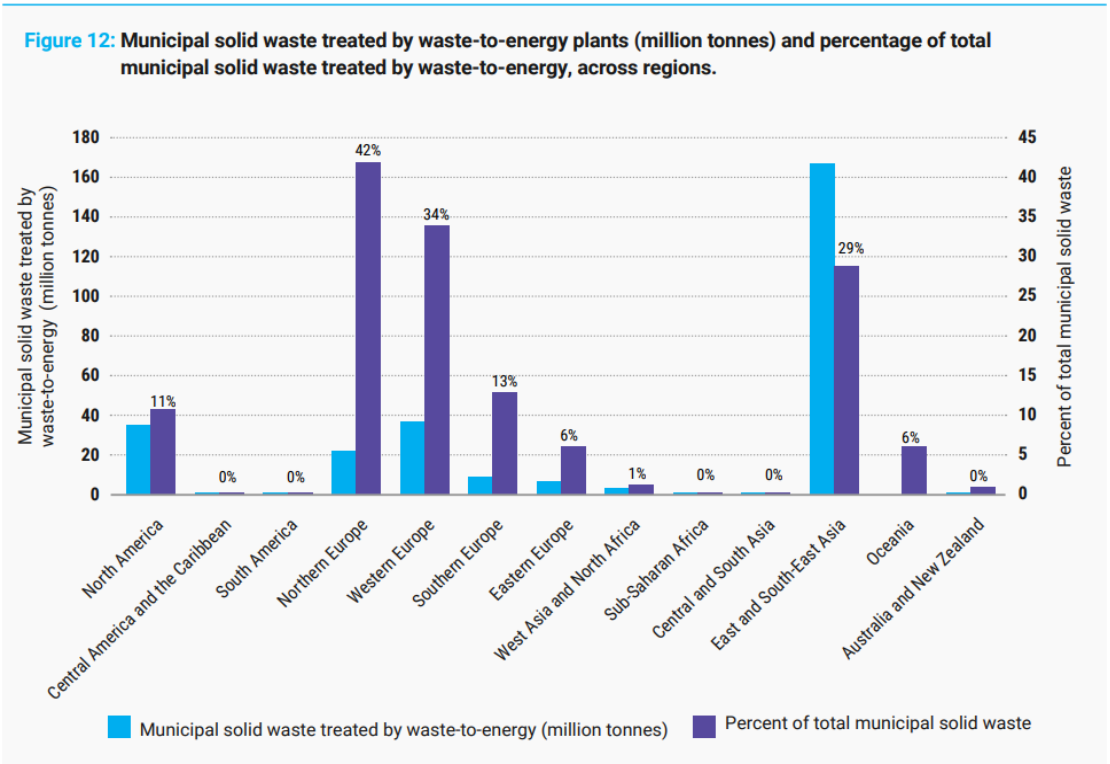
27.2 Technology Maturity

WTE plants have been deployed globally and in the U.S. on a large scale, though primarily limited to industrialized nations that experience high population density and limited land availability (Figure 96). About 13% of the global MSW is used in WTE facilities, with the leading nations being Japan and European countries such as Sweden and Denmark.[362] In the United States alone, WTE facilities comprise 2.5 GW of installed capacity, [361] with a majority sited along the east coast (Figure 97).[363] As the global population grows, experts anticipate waste will increase by 70% by 2050, compared to the 2.01 billion tons produced in 2016.[364] As a mature, stage-four technology, WTE facilities focus on improving operational efficiency and expanding deployment opportunities. This is because they offer a proven solution to the waste and land use issues projected to worsen. However, these facilities will have to

[360] See: https://peakd.com/hive-196387/@oluwoleolaide/my-research-first-waste-to-energy-plant-in-africa
[361] Office of Energy Efficiency and Renewable Energy. (2019). Waste-to-Energy from Municipal Solid Wastes. *U.S. Department of Energy*, Report No. DOE/EE-1796, (August). https://www.energy.gov/sites/prod/files/2019/08/f66/BETO--Waste-to-Energy-Report-August--2019.pdf
[362] Gomstyn, A., & Jonker, A. (2024). Waste-to-energy. *IBM*, (August 12). www.ibm.com/think/topics/waste-to-energy#citation1
[363] Joshi, N. (2021). Waste-to-Energy. *ICLEI Local Governments for Sustainability*. https://renewablesroadmap.iclei.org/wp-content/uploads/2021/11/Waste-to-Energy_Final-1.pdf
[364] Lisbona, P., Pascual, S., & Pérez, V. (2023). Waste to energy: Trends and perspectives. *Chemical Engineering Journal Advances*, 14, 100494. https://doi.org/10.1016/j.ceja.2023.100494

overcome significant operational costs, environmental concerns, and competitive electricity pricing to continue being developed. About 90% of the current WTE capacity in the US was added between 1980 and 1995. Since then, plants have begun to retire, and the economic burden associated with their development has further hindered construction.[365] Puerto Rico has never had a WTE facility, though an incineration facility in Arecibo was in development. It was later stalled and abandoned in 2018 after Hurricane Irma. The facility was expected to accept 2,100 tons of MSW per day and have a nameplate capacity of 77 MW.[366]

Figure 96: Shares of Municipal Solid Waste Being Treated in Waste-to-Energy Facilities Globally[367]



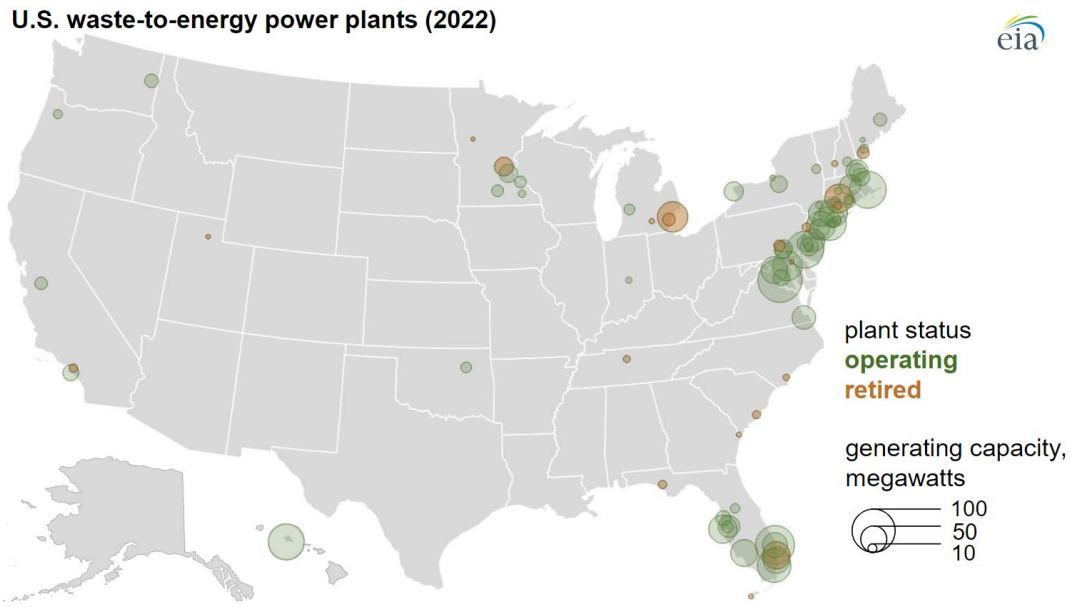
Landfills are typically the alternative to WTE facilities for municipal waste management, primarily due to their significantly lower LCOE when burning methane and other landfill gases (see Cost section). Improvements in WTE facility technologies have been prioritized to increase their economic viability compared to landfills. DOE has conducted extensive research on developing these facilities and has identified several factors that improve system viability.

For incinerator facilities, operational costs are a primary hurdle but can be minimized by lowering the temperature required for nitrogen oxide reduction to meet emission standards. Construction costs for these facilities are also high, particularly for materials like piping and heat exchangers, which often require expensive alloys such as Inconel®. Developing alternative materials could reduce maintenance

[365] Johnson, S., et al. (2022). U.S. Capacity to Convert Waste to Energy Declines After Remaining Steady Since 1994. *U.S. Energy Information Administration*, (August 30). www.eia.gov
[366] "Energy Answers Arecibo, LLC/Energy Answers Arecibo Puerto Rico Renewable Energy Project, PR | US EPA." *US EPA*, 21 Aug. 2024, www.epa.gov/caa-permitting/energy-answers-arecibo-llcenergy-answers-arecibo-puerto-rico-renewable-energy
[367] See: https://docs.nrel.gov/docs/fy24osti/90141.pdf

requirements and capital costs. For anaerobic digestor systems, improvements to the thermocatalytic process could enhance the biogas conversion into usable fuel and co-products. Additionally, investing in co-digestion systems to accommodate the diverse feedstocks in municipal solid waste would increase deployment opportunities for these systems.[368]

Figure 97: Distribution of Waste-to-Energy Facilities in the United States[369]



27.3 Cost

The cost of WTE facilities is the biggest obstacle to widespread deployment, as these facilities tend to be expensive, and their electricity costs often cannot compete with other production sources. The first step in cost comparison is assessing the capital costs associated with constructing these facilities. While construction factors and associated costs vary by WTE facility type, on average, facilities in the United States are built at a rate of about $840 per annual ton of capacity. In contrast, countries like China construct their facilities at an average rate of $250 per annual ton of capacity, benefiting from legislative support, lower labor costs, and a more localized supply chain.[370]

Perhaps the most relevant example in the United States is the incineration plant in Palm Beach, Florida, which was constructed in 2015 and remains the only WTE facility built in the United States since 1995. This facility has a capital cost of $6,720 per kW, which significantly outpaces other forms of energy generation based on the DOE's 2019 report entitled "Waste-to-Energy from Municipal Solid Wastes." An analysis of the LCOE for various WTE facilities shows why landfill gas facilities are more economically viable, provided adequate land is available. The same DOE study shows that the mean LCOE for landfill gas facilities is around $0.059/kWh, compared to $0.14/kWh and $0.18/kWh for incineration and

[368] Office of Energy Efficiency and Renewable Energy. (2019). Waste-to-Energy from Municipal Solid Wastes. *U.S. Department of Energy*, DOE/EE-1796. www.energy.gov/sites/prod/files/2019/08/f66/BETO--Waste-to-Energy-Report-August--2019.pdf
[369] See: https://www.eia.gov/todayinenergy/detail.php?id=53639
[370] Wu, J.S. (2018). *Capital cost comparison of waste-to-energy (WTE) facilities in China and the U.S.* (Master's thesis). Columbia University.

anaerobic digestion facilities. It is important to note that these costs do not reflect the potential cost for such a facility in Puerto Rico, which would likely be more expensive.

Table 61: Capital Costs of Typical Commercial-Scale Power Generation Facilities (2016$)[368]

	Palm Beach MSW Incineration Plan	Ultra-Supercritical Coal	Advanced Nuclear	Natural Gas Combined Cycle	Natural Gas Combustion Turbine	Onshore Wind	Photovoltaic - Fixed
Nominal capacity (MW)	100	650	2,234	702	100	100	20
Capital cost ($/Kw)	$6,720	$3,636	$5,945	$978	$1,101	$1,877	$2,671

Table 62: Levelized Cost of Energy (LCOE) for Landfill Gas (LFG) Incineration and Anaerobic Digestion[368]

LCOE (U.S. Cents per kWh)				
Technology	**Low**	**High**	**Mean**	**Reference**
LFG-1A	1.6	2.5	2.1	1
LFG-2A	5	6.8	5.9	1
MSW	12	17	14	1
AD	14	27	18	2.3

Across different WTE technologies, costs can vary greatly, with the same story of economic infeasibility persisting. Based on a 2017 report by GIZ, the German international cooperation for sustainable development agency, initial investments in these facilities can be in the tens of millions, and O&M costs can range from eight to 34 dollars per ton of waste input. It is important to note that these figures are estimated for developing countries, which used actual values from Swiss WTE facilities and assumed fractional decreases in costs and maintenance attributed to differences in architectural design, level of automation, and quality of materials applied, among other considerations, to arrive at the developed nation estimates.[371]

Another unique attribute of Municipal WTE facilities is their additional revenue streams aside from the sale of the electricity generated, namely the tipping cost. This refers to the cost, in dollars per ton of MSW, charged by the WTE facility for municipalities to dump their waste at the facility. Landfill facilities also have tipping fees, but the price structure between the two will differ based on the net production costs of energy and capacity at each facility, among other considerations. According to a 2008 EPA study on the potential

[371] Mutz, D., Hengevoss, D., Hugi, C. & Gross, T. (2017). Waste-to-energy options in municipal solid waste management: A guide for decision-makers in developing and emerging countries. *Deutsche Gesellschaft für Internationale Zusammenarbeit*. www.giz.de/en/downloads/GIZ_WasteToEnergy_Guidelines_2017.pdf

for Municipal WTE in Puerto Rico, estimates for tipping fees in a landfill would be between $45 and $60 per ton, while fees at a WTE facility would be between $50 and $62 per ton.[372]

Table 63: Cost Estimates for Five Waste-to-Energy Technologies in Developing Countries[371]

WTE Technology	Incineration	Co-processing Plant	Anaerobic Digestion Plant	Landfill Gas Capture Collection		Pyrolysis/Gasification Plant
Capacity	150,000 tons per year	50,000 tons per year, 20-year operation	50,000 - 150,000 tons per year, 20-year operation	390,000 – 850,000 tons per year, 21-year operation		250,000 tons per year, 20-year operation
Initial investment	$25 – $64 million	$4 - $21 million (including preprocessing)	$10 - $17 million	$5 million (CDM-Brazil)	$4.5 million (CDM-China)	$68 - $101 million
Capital costs per ton of waste input	$18 - $46 per ton	$8 - $21 per ton	$10 - $16 per ton	$0.7 per ton	$1.2 per ton	$25 - $32 per ton
O&M costs per ton	$17 - $30 per ton	$8 - $17 per ton	$8 - $13 per ton	$0.7 per ton	$0.25 per ton	$25 - $34 per ton
Total cost per ton	$35 - $76 per ton	$17 - $38 per ton	$18 - $29 per ton	$1.3 per ton	$1.4 per ton	$55 - $72 per ton
Revenues from energy sales per ton	$1.7 - $8.5 per ton (electricity)	$0.8 - $4 per ton	$6 - $13 per ton	$2 per ton	$2.8 per ton	$1.5 - $4 per ton
Cost to be covered per ton of waste input	$15 - $34 per ton	$16 - $34 per ton	$12 - $15 per ton	$0.7 per ton	$1.4 per ton	$53 - $68 per ton

27.4 Supply-Chain

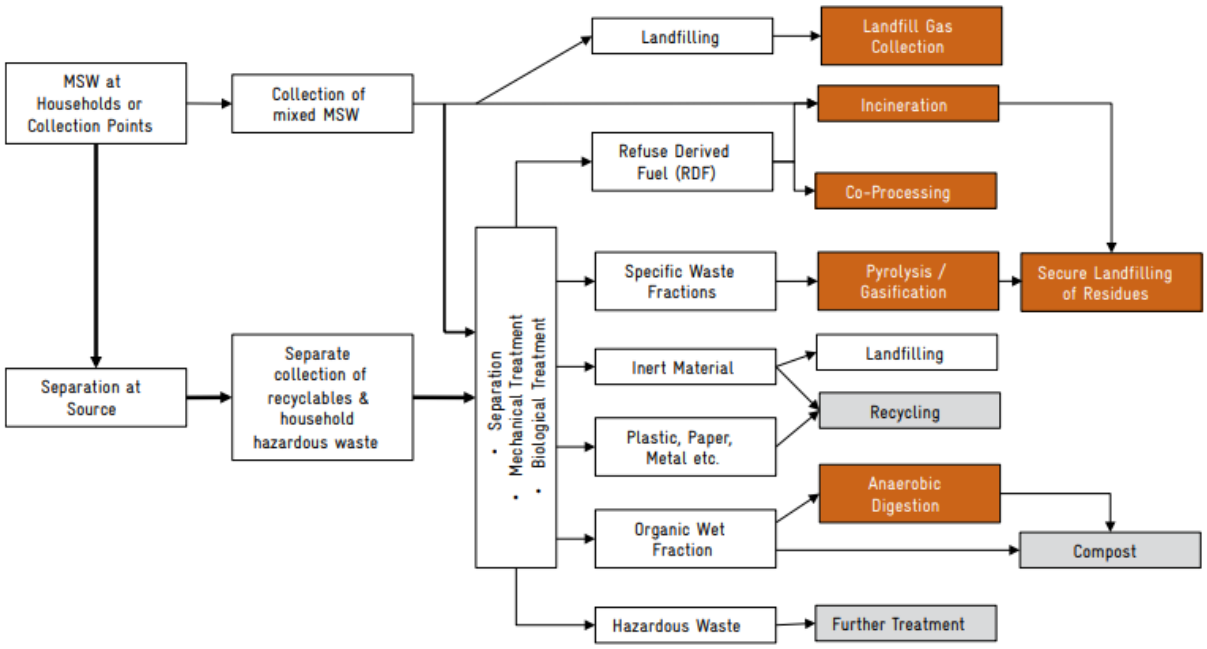
The components of a WTE system are relatively common. However, the components required for constructing these systems, such as air distribution, emission controls, and automation systems, are generally manufactured in Europe, where these facilities are more prevalent. One reason China has been able to develop these WTE projects at a lower cost is its ability to acquire these manufacturing processes and produce the components locally using a more affordable labor force. Additionally, by standardizing the design of specific system components, such as moving grates for incineration, China can produce them for multiple facilities rather than making each project unique. These processes are not yet established in the United States, partly due to the lack of demand, as evidenced by the fact that only one new WTE facility has been built since 1995.

Beyond the construction of the facilities themselves, the supply of MSW is crucial to the facility's operation. Puerto Rico has 29 landfills, nearly all at or near capacity. The same municipal transportation system that delivers waste to the landfills can transport MSW to the WTE facility for sorting and treatment. A 2008 American Society of Mechanical Engineers study compared the lifecycle impacts of a landfill

[372] Carim, M., Blake, W., Amerman, A., Gridley, B., Kurpiewski, M., Lee, S.A. (2007). Waste to energy: A possibility for Puerto Rico. *Columbia University*, (May). www.sipa.columbia.edu/sites/default/files/migrated/migrated/documents/PuertoRicoWastetoEnergyfinal_0.pdf

versus an incineration-based WTE facility in Puerto Rico. It demonstrated the shared MSW collection and transportation infrastructure.[373] Figure 98 illustrates the flow of MSW inputs for different WTE technologies, including typical landfill gas facilities.

Figure 98: Flow Chart of Municipal Solid Waste from Source to Use in Waste-to-Energy Facilities[374]



27.5 Construction and Development

Limited information is available regarding the construction phase of WTE facilities. However, based on anecdotal timelines from projects like New Sky Energy's WTE facility in the Philippines, it is reasonable to expect a construction timeline of approximately two years in addition to the time needed for permitting and land acquisition. Construction timelines will largely depend on the size of the project, but one of the benefits of WTE facilities is their relatively small footprint. A 2008 EPA report on WTE feasibility in Puerto Rico estimated that a conservatively projected WTE facility would only require 10 acres.[375] Another crucial site consideration would be the proximity to urban areas, as minimizing transportation costs for MSW would be crucial.

[373] Balaguer-Dátiz, G. & Krishnan, N. (2008). Life Cycle Comparison of Two Options for MSW Management in Puerto Rico: Thermal Treatment vs Modern Landfilling. *American Society of Mechanical Engineers*. https://wtert.org/wp-content/uploads/2020/10/nawtec16-1928.pdf

[374] See: https://www.researchgate.net/figure/Overview-of-MSW-material-flow-and-its-different-utilization-and-treatment-options_fig2_322772063

[375] Carim, M., Blake, W., Amerman, A., Gridley, B., Kurpiewski, M., Lee, S.A. (2007). Waste to energy: A possibility for Puerto Rico. *Columbia University*, (May). www.sipa.columbia.edu/sites/default/files/migrated/migrated/documents/PuertoRicoWastetoEnergyfinal_0.pdf

27.6 Operation

The operation of WTE facilities can vary slightly depending on the technology used and the size of the facility. However, these plants typically employ technicians, boiler operators, safety inspectors, and other skilled workers and engineers. For example, a New Jersey WTE plant that processes 2,800 tons of waste daily employs about 90 full-time staff members. Regular maintenance costs approximately 2% of the initial capital investment.[375] Due to the complexity of these systems, compared to the relatively simple landfill gas facilities, the labor force needed to operate WTE plants must possess a high level of experience and skill.

27.7 Sustainability

Recent iterations of WTE facilities have focused heavily on minimizing environmental and human health impacts, particularly incineration, which produces bottom ash (90%) and fly ash (10%) containing heavy metals.[376] Fly ash holds most heavy metals, but this can be mitigated by cooling the exhaust gases to condense the heavy matter into particulate matter, which can be filtered out. While incineration plants also produce toxic chemicals, several studies have shown that modern WTE facilities mitigate this risk by maintaining combustion temperatures greater than 900°C, reducing the levels of these toxic compounds to non-detectable levels.[377] These projects typically last around 50 years. Compared to landfill gas facilities, which require extensive land and water resources and contribute to soil degradation and water runoff, WTE facilities present a much more sustainable long-term option.[378] A conservative 2008 emission estimate for a Puerto Rican MSW incineration facility showed that all key values were significantly below EPA standards (Table 64**Error! Reference source not found.**). Studies of incineration plants generally indicate a range of 0.02 to 1.1 kg CO_2e per kWh generation.[379]

Table 64: Estimated Emission Levels from the 2008 Incineration Waste-to-Energy Facility in Puerto Rico with the Environmental Protection Agency Emission Standards[380]

Pollutant	Thermoselect Emissions* (Gas Engine) (mg, Nm)	U.S. EPA Standards** (mg, Nm^3)
Particulate matter (PM)	0.2	11
Sulfur dioxide (SO2)	0.16	63
Nitrogen oxides (NOx)	14	264
Hydrogen chloride (HCl)	<5	29

[376] Ram, C., Kumar, A., & Rani, P. (2021). Municipal solid waste management: A review of waste to energy (WtE) approaches. *BioResources*, 16(2), 4275-4320. Retrieved from https://gp4sustainability.ncsu.edu/waste-to-advanced-resources/.
[377] Traven, L. (2023). Sustainable Energy Generation from Municipal Solid Waste: A Brief Overview of Existing Technologies. *Case Studies in Chemical and Environmental Engineering*, 8, 100491, (December). https://doi.org/10.1016/j.cscee.2023.100491
[378] Tabibi, A. (2024). WtE as a sustainable waste management strategy. *Green.org*, (January 30). https://green.org/2024/01/30/wte-as-a-sustainable-waste-management-strategy
[379] Han, X., Chang, H., Wang, C., Tai, J., Karellas, S., Yan, J., Song, L., Bi, Z. (2023). Tracking the life-cycle greenhouse gas emissions of municipal solid waste incineration power plant: A case study in Shanghai. *Journal of Cleaner Production*, Volume 398, 136635, (April 20). https://www.sciencedirect.com/science/article/pii/S095965262300793X
[380] Han, X., Chang, H., Wang, C., Tai, J., Karellas, S., Yan, J., Song, L., Bi, Z. (2023). Tracking the life-cycle greenhouse gas emissions of municipal solid waste incineration power plant: A case study in Shanghai. *Journal of Cleaner Production*, Volume 398, 136635, (April 20). https://www.sciencedirect.com/science/article/pii/S095965262300793X

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Pollutant	Thermoselect Emissions* (Gas Engine) (mg, Nm)	U.S. EPA Standards** (mg, Nm^3)
Carbon monoxide (CO)	3	45
Mercury (Hg)	0.002	0.06
Total organic carbon (TOC)	1.71	10***
Dioxins (TEQ), ng/m3	0.00039	0.14

*Emissions averaged from Thermoselect Plants in Karlsruhe, Germany, and Chiba, Japan.
**Emission factors corresponding to scenarios 1 and 2, respectively.
***EU emission standard.

Appendix 6: Core Scenario Runs

28.0 Results for Core Scenarios

28.1 Scenario 1- Base assumptions for all variables

Scenario 1 serves as the foundational basis for the development of the Preferred Resource Plan (PRP). This scenario incorporates all defining characteristics that establish all scenarios as “Base”, which represent the most probable trajectory of key planning assumptions.

The primary distinction between Scenario 1 and the PRP lies in the treatment of the ASAP BESS Phase 2 projects. Scenario 1 assumes these projects as fixed components of the resource portfolio. In contrast, the PRP considers the ASAP BESS Phase 2 projects as optional, allowing for greater flexibility in resource selection. Additionally, Scenario 1 utilizes a generic battery energy storage system (BESS) efficiency assumption, which was subsequently refined and updated in the PRP to reflect more accurate performance expectations

28.1.1 Annual Capacity Contribution by Resource

Table 65 and Table 66 present information about the MW of generator and battery resource additions and retirements that occur under Scenario 1. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 65: Capacity Additions Summary for Scenario 1 Base assumptions for all variables (MW)

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	645
Tranche 1 & 2 Solar	160	579	66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	615	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	615
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	226	-	452	-	-	-	-	-	678
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	214	226	226	-	172	373	-	-	-	210	1,421
BESS, 4 HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Gas Gen.*	0	0	0	478	0	0	70	226	105	0	0	0	408	0	0	0	0	0	0	0	1287
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2519	767	617	47	57	142	300	173	62	267	286	932	96	745	506	158	184	194	370	9199

*Includes LNG SJ, CS, EcoEléctrica and Trucked.

Table 66: Resource Retirement Summary for Scenario 1 Base assumptions for all variables (MW)

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	-	-	-	-	178	165	-	-	-	-	-	-	-	-	490
Fuel Oil	-	-	-	-	-	300	100	180	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	136	226	-	360	552	373	-	-	-	210	1857
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
DBESS- Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	-	63	87	-	792	300	100	182	474	-	314	421	55	360	552	373	2	2	-	210	4287

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.1.2 Energy Production by Fuel or Resource

Table 67 provides details on the source of energy production by fuel type and resource for Scenario 1.

Table 67: Scenario 1 Base assumptions for all variables. 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
Coal	3164	3121	3381	3145	3110	3140	3076	3059	3047	-	-	-	-	-	-	-	-	-	-	-
Diesel	2099	1738	78	13	-	13	20	23	8	7	3	11	7	5	19	3	7	6	7	5
Fuel Oil	2113	2315	513	153	2	58	35	11	-	-	-	-	-	-	-	-	-	-	-	-
LNG – EcoElec and CS	5676	5199	3957	3948	4065	4165	4182	4316	4119	4469	4403	4361	4780	4092	3999	3941	3954	3883	3877	3391
LNG-SJ	4197	3866	3857	3412	5772	5782	5726	5609	5668	7867	7754	7611	6530	7656	7413	6823	5776	4957	4088	3783
Hydro	26	23	67	149	149	149	177	177	178	177	177	177	178	178	177	177	178	177	177	177
UPV	289	398	740	854	946	945	944	944	943	898	900	899	844	725	726	725	728	725	725	726
Land Based Wind	258	269	268	269	269	269	268	268	268	268	268	268	270	272	269	268	269	269	268	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	-	-
LNG - Trucked	725	606	231	708	69	563	467	281	80	318	289	268	640	100	111	8	41	38	17	16
Biodiesel	-	-	-	-	-	-	-	-	-	-	-	4	42	7	33	530	1220	1902	2435	2909
Solar - Tranche 1	-	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1261	1263	1262	1267	1263	1259	1259
Solar - Tranche 2	-	-	-	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107
CHP	142	346	426	511	667	751	729	698	742	803	788	757	727	699	677	661	653	654	654	649
DPV	233	545	652	687	731	780	841	915	1005	1097	1189	1268	1351	1439	1551	1683	1842	2011	2207	2423
DR	-	217	3100	3047	916	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
BESS- 4 HR	-	7	117	154	166	182	178	171	146	188	191	190	204	194	193	207	189	200	230	258
BESS- Tranche 1	-	-	154	274	245	278	290	266	224	303	299	298	310	304	297	327	290	311	363	428
BESS- Tranche 2	-	-	-	16	34	36	34	32	26	36	35	35	38	35	36	39	33	37	42	55
BESS- Tranche 4	-	-	-	17	37	36	34	33	26	35	37	35	39	35	35	40	34	35	43	56
ASAP BESS	-	-	102	361	299	320	301	300	260	334	326	326	349	334	327	348	318	339	387	436
DBESS	-	8	9	5	12	19	28	31	35	39	44	49	55	60	67	76	85	89	94	100

28.1.3 Annual Emissions by Resource

Table 68 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 68: Scenario 1 Annual Emissions by resource (tonCO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	1675843	73478	11258	190	10824	12428	10333	9321	27479	5291	4690	4198	6951	3502	2008	3718	4457	2553	6082	14464
Fuel Oil	3478098	605155	151139	5260	86832	34034	6709	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	159164	1949202	2126407	579981	271461	227405	270924	231485	1052301	778335	1042738	921016	1378901	1608362	1548536	1412750	1258669	1125717	992762	823262
Biodiesel	0	0	0	0	0	0	0	0	0	0	22287	44670	47420	379284	862727	1362055	1850217	2268443	2640881	2936132

28.1.4 Annual Fuel Consumption by Fuel Type

Table 69 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 69: Scenario 1 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	20,577	857	232	0	102	194	290	92	77	37	175	163	76	227	751	991	1,175	1,114	948	503
Fuel Oil	42,015	7,306	1,770	61	1,055	416	133													
LNG	81,686	100,105	97,521	83,462	79,865	78,932	77,628	76,052	100,868	99,163	97,180	93,233	86,360	83,814	77,519	73,370	66,362	59,069	52,749	46,809
Biodiesel											67	368	82	341	5,661	8,241	12,787	16,633	20,218	23,392

28.1.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 70 shows the cost components of Scenario 1 each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 1.

Table 70 includes the production costs of the system each year, including include 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 70 is equal to the sum of the production costs and the fixed costs.

Table 70: Scenario 1 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2373	1796	1697	1489	1496	1495	1504	1520	1656	1671	1685	1634	1515	1522	1635	1726	1821	1855	1906	1951
Total Production Cost	3081	2792	2917	2957	2950	2955	2995	3035	2982	3022	3055	3000	2907	2901	3017	3124	3246	3304	3386	3466
Total System Costs	3285	3146	3486	3690	3759	3775	3846	3962	3950	3970	4012	3932	4085	4096	4359	4487	4858	4754	4860	4959

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Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
PVRR	2817	5314	7877	10388	12757	14960	17038	19020	20849	22552	24145	25591	26982	28273	29545	30758	31974	33075	34118	35103
Total Production Cost, $/kWh*	0.166	0.153	0.161	0.164	0.165	0.166	0.170	0.175	0.173	0.177	0.181	0.180	0.176	0.178	0.187	0.195	0.204	0.210	0.217	0.224
Total System Cost, $/kWh*	0.177	0.173	0.192	0.205	0.210	0.213	0.218	0.228	0.230	0.233	0.237	0.236	0.248	0.252	0.271	0.281	0.305	0.302	0.311	0.320

*Total system costs are not equivalent to tariffs.

28.2 Scenario 2- High load (peakier / Low LF) with base assumptions for other variables

28.2.1 Annual Capacity Contribution by Resource

Table 71 and Table 72 present information about the MW of generator and battery resource additions and retirements that occur under the Scenario 2. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 71: Capacity Addition Summary (MW) for Scenario 2

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5			-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	645
Tranche 1 & 2 Solar	160	579	66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	615	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	615

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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	Total
New Biodiesel	0	0	0	0	0	0	0	0	0	0	452	35	0	172	373	0	0	373	0	0	1405
Biodiesel Conversions	0	0	0	0	0	0	0	0	0	0	0	0	0	470	0	0	0	0	0	0	470
BESS, 4 HR	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60
New Gas Gen.*	-	-	-	478	-	860	-	-	-	-	-	-	-	373	-	-	-	-	-	-	1,711
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2519	827	617	47	917	72	74	68	62	505	95	72	1111	494	133	158	557	194	160	9459

*Includes LNG SJ, CS and Trucked.

Table 72: Scenario 2 Resource Retirements (MW)

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	280	-	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	452	35	-	532	753	-	-	373	-	-	2145
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS- Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	-	63	87	-	792	300	280	2	474	-	452	330	55	532	753	-	2	375	-	-	4497

*Includes LNG SJ, CS, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.2.2 Energy Production by Fuel or Resource

Table 73 provides details on the source of energy production by fuel type and resource for Scenario 2.

Table 73: Scenario 2 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
Coal	3181	3386	3143	3138	3163	2053	2465	2793	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	2197	165	80	4	62	8	9	8	9	8	6	7	6	3	7	7	8	9	9	8
Fuel Oil	2423	919	593	32	211	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	5485	4018	3886	4066	4369	4703	4385	4305	5124	5018	4561	4606	4594	6431	4102	3738	3302	3955	3802	3457
LNG-SJ	4114	4323	3775	6214	6361	8331	8084	7630	9321	9353	9085	8898	8857	7237	8300	7675	7136	5389	4710	4245
Hydro	22	67	149	149	149	178	178	178	177	177	177	178	177	177	178	178	177	177	177	178
UPV	397	740	854	946	945	944	944	942	898	900	899	844	725	726	725	727	724	725	726	725

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
LNG - Trucked	663	372	945	195	1150	41	60	36	152	127	766	777	810	69	173	99	68	149	68	40
Biodiesel	0	0	0	0	0	0	0	0	0	0	24	49	51	405	1369	2223	3064	3778	4426	4990
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1262	1263	1263	1267	1262	1262	1262	1260
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	346	426	511	667	751	729	698	742	802	788	757	727	699	676	661	653	654	654	653	653
DPV	544	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1683	1842	2010	2207	2424	2668
Emergency Generator	256	3379	3466	1838	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	0	6	6	7	8	8	12	14	12	21	25	24
BESS- 4 HR	7	136	194	213	240	161	165	191	178	185	246	244	239	239	232	246	260	240	261	294
BESS- Tranche 1	0	156	268	260	315	215	217	251	238	246	331	332	328	290	301	305	325	315	337	393
BESS- Tranche 2	0	0	18	39	43	24	25	30	29	30	39	38	38	39	39	40	46	39	45	56
BESS- Tranche 4	0	0	18	41	44	24	25	29	27	29	40	41	39	41	39	42	47	38	42	59
ASAP BESS	0	109	372	330	357	240	247	282	267	277	352	353	345	345	336	359	378	358	391	430
DBESS	8	9	5	12	19	28	31	35	40	44	49	55	61	68	76	84	89	95	101	106

28.2.3 Annual Emissions by Resource

Table 74 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 74: Scenario 2 Annual Emissions by resource (tonCO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				
Diesel	2134226	155751	74733	3883	60094	7375	7960	7420	8560	7500	5150	6696	5821	3162	6784	5924	7727	7882	8357	7778
Fuel Oil	3666477	1016027	575553	35469	251409	3969	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	5050570	6476013	6370579	5749709	5374847	5834620	5528624	5208006	6602115	6564735	6342454	6267031	6274122	5713024	5379377	4878272	4428105	4149836	3728203	3334322
Biodiesel	0	0	0	0	0	0	0	0	0	0	22287	44670	47420	379284	862727	1362055	1850217	2268443	2640881	2936132

28.2.4 Annual Fuel Consumption by Fuel Type

Table 75 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 75: Scenario 2 Annual Fuel consumption by Fuel Type (BBtu)

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

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	26,178	1,910	917	48	737	90	98	91	105	92	115	175	159	645	1,249	1,746	1,913	1,769	1,400	817
Fuel Oil	44,290	12,273	6,953	428	3,037	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	86,351	110,723	108,920	98,305	91,896	99,757	94,525	89,043	112,879	112,240	108,439	107,150	107,271	97,678	91,973	83,406	75,709	70,951	63,742	57,008
Biodiesel											222	456	495	4,054	9,433	15,061	20,913	26,198	31,148	35,351

28.2.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 76 shows the cost components of Portfolio C each year during the planning period, and it indicates the total PVRR needed to recover the costs of Portfolio C.

Table 76: Portfolio C Resulting from Scenario 2 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2581	2012	1921	1668	1687	1665	1671	1664	1816	1855	1831	1831	1835	1883	2012	2153	2303	2443	2531	2598
Total Production Cost	3290	3009	3144	3137	3144	3163	3175	3207	3166	3231	3232	3218	3216	3284	3391	3565	3744	3889	4008	4111
Total System Costs	3494	3363	3737	3895	3977	4279	4299	4342	4310	4354	4364	4325	4336	4653	4781	4977	5403	5388	5531	5649
PVRR	2995	5665	8412	11063	13569	16066	18389	20561	22558	24425	26158	27748	29224	30691	32087	33432	34784	36033	37219	38341
Total Production Cost, $/kWh*	0.166	0.153	0.160	0.160	0.161	0.163	0.164	0.167	0.165	0.169	0.169	0.169	0.170	0.174	0.181	0.191	0.200	0.209	0.216	0.222

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Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Total System Cost, $/kWh*	0.176	0.171	0.191	0.199	0.204	0.220	0.222	0.226	0.225	0.227	0.228	0.228	0.229	0.247	0.255	0.266	0.289	0.290	0.298	0.306

*Total system costs are not equivalent to tariffs.

28.3 Scenario 3- Base load with high fossil capital costs

28.3.1 Annual Capacity Contribution by Resource

Table 77 and Table 78 present information about the MW of generator and battery resource additions and retirements that occur under the Scenario 3. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 77: Capacity Addition Summary (MW) for Scenario 3

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	615	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	615
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	226	-	-	-	-	-	-	-	226
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	-	226	-	-	373	-	-	373		-	972

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
BESS, 4 HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Gas Gen.*	-	-	-	478	-	-	296	-	-	373	-	-	373	-	-	-	-	-	-	-	1520
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2519	767	617	47	57	368	74	68	435	53	286	671	96	494	133	158	557	194	160	8531

*Includes LNG SJ, CS and Trucked.

Table 78: Scenario 3 Resource Retirements (MW)

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	100	180	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	285	226	-	740	373	-	-	373	-	-	1997
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS- Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	-	63	87	-	792	300	100	182	474	-	285	521	55	740	373	-	2	375	-	-	4349

*Includes LNG SJ, CS, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.3.2 Energy Production by Fuel or Resource

Table 79 provides details on the source of energy production by fuel type and resource for the Scenario 3.

Table 79: Scenario 3 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
Coal	3164	3123	3382	3144	3111	3140	3083	2848	3066	0	0	0	0	0	0	0	0	0	0	0
Diesel	2099	1739	78	16	0	11	17	7	8	16	7	3	3	5	17	3	4	5	9	8
Fuel Oil	2112	2315	507	151	2	63	32	5	0	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	5675	5199	3957	3955	4073	4160	4183	4117	4120	4439	3839	4049	4350	5613	5310	3907	3351	2911	3922	3553
LNG-SJ	4197	3865	3863	3410	5771	5782	5724	6175	5648	7845	8507	8029	7336	6134	6123	6763	6356	5940	3985	3576
Hydro	26	23	67	149	149	149	177	177	178	177	177	177	178	176	175	177	178	177	177	177
UPV	289	398	740	854	946	945	944	944	943	898	900	899	844	720	720	724	726	720	725	726
Land Based Wind	258	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0
LNG - Trucked	727	605	232	710	69	565	466	133	83	359	81	165	308	90	76	93	75	29	66	40
Biodiesel	0	0	0	0	0	0	0	0	0	0	0	5	11	5	43	535	1225	1907	2433	2910
Solar - Tranche 1	0	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1258	1259	1262	1264	1258	1260	1261
Solar - Tranche 2	0	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107
CHP	142	346	426	511	667	751	729	698	742	803	788	757	727	698	676	661	650	653	654	652
DPV	233	546	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1550	1683	1842	2011	2207	2424
Emergency Generator	0	220	3098	3040	907	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	0	1	2	3	4	5	6	6	7	8	6	12	14	13	21	25
BESS- 4 HR	0	7	119	153	163	184	178	137	145	196	160	180	217	168	152	205	197	186	223	240
BESS- Tranche 1	0	0	155	274	247	276	287	221	231	310	251	277	345	240	218	320	304	273	340	368
BESS- Tranche 2	0	0	0	15	34	37	34	25	27	37	30	34	42	33	30	39	39	35	42	47

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
BESS- Tranche 4	0	0	0	16	37	37	33	25	27	38	28	33	41	35	30	40	39	37	43	48
ASAP BESS	0	0	100	361	299	322	300	241	259	335	285	324	365	297	275	345	339	320	373	400
DBESS	0	8	9	5	12	19	28	31	35	39	44	49	55	60	68	76	85	89	95	101

28.3.3 Annual Emissions by Resource

Table 80 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 80: Scenario 3 Annual Emissions by resource (CO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	1678319	75057	14487	210	10158	15954	6702	7320	15559	6427	2291	3025	4808	16152	2779	3783	4579	7770	6731	4289
Fuel Oil	3477710	598092	148382	5230	89377	31415	4830	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	4776780	5852550	5703577	4878915	4669456	4616210	4755832	4450640	5893390	5425400	5358079	5158496	4887635	4746410	4536399	4094933	3697280	3455096	3073945	2728399
Biodiesel	0	0	0	0	0	0	0	0	0	0	4361	9377	4591	37678	327879	745350	1136236	1436390	1709647	1934068

28.3.4 Annual Fuel Consumption by Fuel Type

Table 81 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 81: Scenario 3 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	20,586	921	178	3	125	196	82	90	191	79	38	57	67	258	477	962	1,173	1,154	923	528
Fuel Oil	42,010	7,225	1,792	63	1,080	379	58	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	81,670	100,063	97,516	83,417	79,835	78,925	81,312	76,094	100,761	92,760	91,609	88,197	83,566	81,151	77,560	70,013	63,214	59,073	52,556	46,648
Biodiesel	-	-	-	-	-	-	-	-	-	-	43	96	48	403	3,585	8,242	12,843	16,588	20,164	23,286

28.3.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 82 shows the cost components of Scenario 3 each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 3.

Table 82: Scenario 3 System Costs and PVRR

Cost($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2373	1795	1697	1490	1496	1494	1535	1519	1655	1579	1588	1538	1478	1493	1548	1663	1769	1850	1896	1938
Total Production Cost	3082	2791	2917	2957	2950	2954	3034	3034	2976	2945	2989	2920	2881	2848	2917	3065	3198	3285	3362	3438
Total System Costs	3286	3145	3487	3691	3759	3774	3976	3986	3937	4013	4071	3976	4152	4135	4226	4396	4777	4702	4803	4895
PVRR	2817	5313	7876	10388	12757	14959	17107	19101	20924	22645	24262	25724	27137	28441	29674	30862	32058	33147	34178	35150
Total Production Cost, $/kWh*	0.166	0.153	0.161	0.164	0.165	0.166	0.172	0.175	0.173	0.172	0.177	0.175	0.175	0.175	0.181	0.192	0.201	0.209	0.215	0.222

Total System Cost, $/kWh*	0.177	0.173	0.192	0.205	0.210	0.212	0.226	0.229	0.229	0.235	0.241	0.238	0.252	0.254	0.262	0.275	0.300	0.299	0.308	0.316

*Total system costs are not equivalent to tariffs.

28.4 Scenario 4- Base load with low renewable energy capital costs and high fossil capital costs

28.4.1 Annual Capacity Contribution by Resource

Table 83 and Table 84 present information about the MW of generator and battery resource additions and retirements that occur under the Scenario 4. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 83: Capacity Addition Summary (MW) for Scenario 4

Unit	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645

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Unit	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	615	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	615
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	552	-	-	-	373	-	-	-	373	-	1,298
BESS, 4 HR	-	-	-	-	-	-	240	-	-	-	-	-	-	-	-	-	-	-	-	-	240
BESS, 6 HR	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	60
New Gas Gen.*	-	-	-	478	-	-	226	-	-	226	373	-	-	373	-	-	-	-	-	-	1676
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2519	767	617	47	57	538	74	68	288	1038	60	72	469	494	133	158	184	567	160	9087

*Includes LNG SJ, CS and Trucked.

Table 84: Scenario 4 Resource retirements (MW)

Unit	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	100	180	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2		-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	552	360	-	-	753	-	-	-	373	-	2038

Unit	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS- Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	0	63	87	0	792	300	100	182	474	0	552	655	55	0	753	0	2	2	373	0	4390

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.4.2 Energy Production by Fuel or Resource

Table 85 provides details on the source of energy production by fuel type and resource. There is notable growth in the generation of energy by biodiesel, which is 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 85: Scenario 4 Energy Production by Fuel or Resource (GWh)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3124	3378	3143	3111	3139	3073	2842	3067	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	1743	75	16	0	11	13	8	8	43	5	4	6	5	7	4	3	4	2	8	7
Fuel Oil	2311	512	151	2	61	35	8	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	5188	3940	3961	4067	4161	4179	5105	4919	5902	5237	4001	4178	4052	5322	3912	3352	2850	2214	3525	2940
LNG-SJ	3863	3860	3410	5772	5785	5738	5159	4832	6223	7030	8017	7639	7603	6161	6803	6417	6030	5771	3637	3491
Hydro	23	67	149	149	149	177	177	178	177	177	177	178	177	175	177	178	177	177	177	178
UPV	398	740	854	946	945	944	944	942	898	900	899	844	724	720	725	727	717	723	725	727
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
LNG - Trucked	606	231	709	69	565	466	167	104	497	159	217	175	188	56	47	15	8	2	12	7
Biodiesel	0	0	0	0	0	0	0	0	0	0	13	5	10	25	536	1222	1914	2439	2910	3306
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1261	1257	1262	1265	1255	1255	1259	1264
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	346	426	511	667	751	729	698	742	803	788	757	727	699	675	660	652	650	649	653	652
DPV	546	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1683	1842	2011	2207	2424	2668

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Emergency Generator	226	3122	3034	911	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	5	6	6	7	8	10	11	13	16	11	25	27
BESS- 4 HR	7	117	152	166	183	180	218	225	306	220	257	280	281	213	290	278	275	278	342	372
BESS- 6 HR	0	0	0	0	0	0	0	0	0	0	33	36	34	27	36	35	35	35	44	47
BESS- Tranche 1	0	150	272	247	279	281	187	200	269	204	241	267	263	188	275	247	247	250	320	356
BESS- Tranche 2	0	0	16	33	35	34	23	24	36	24	29	33	33	25	34	31	32	32	40	43
BESS- Tranche 4	0	0	17	36	37	31	23	23	34	25	29	31	29	24	34	31	33	32	39	45
ASAP BESS	0	100	360	298	323	306	237	240	322	246	282	297	288	247	301	295	294	295	358	383
DBESS	8	9	5	12	19	28	31	35	39	43	49	55	60	68	76	84	89	95	101	106

28.4.3 Annual Emissions by Resource

Table 86 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 86: Scenario 4 Annual Emissions by resource (CO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	1682880	71420	14879	25	10073	12265	6908	7619	42354	4565	3264	5633	4225	7386	3961	2917	3433	1631	7476	6120
Fuel Oil	3465847	604980	147747	5287	88548	34335	7854	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	4776701	5852668	5701759	4879426	4670836	4620350	4751249	4446569	5871249	5911671	5228164	5113808	5039143	4757557	4528000	4082164	3694151	3286842	3071609	2728655
Biodiesel	0	0	0	0	0	0	0	0	0	0	12340	5683	9771	22906	325627	736044	1130908	1424191	1713218	1931844

28.4.4 Annual Fuel Consumption by Fuel Type

Table 87 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 87: Scenario 4 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	20,642	876	183	0	124	150	85	93	520	56	69	81	70	127	489	940	1,154	1,070	934	550
Fuel Oil	41,866	7,308	1,785	64	1,070	415	95		-	-	-	-	-	-	-	-	-	-	-	-
LNG	81,669	100,065	97,485	83,425	79,859	78,996	81,234	76,025	100,383	101,074	89,388	87,433	86,156	81,342	77,417	69,794	63,160	56,196	52,516	46,653
Biodiesel	-	-	-	-	-	-	-	-	-	-	123	58	102	245	3,561	8,139	12,783	16,448	20,206	23,260

28.4.5 Cash-Flow Table

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 88 shows the cost components of Portfolio E each year during the planning period, and it indicates the total PVRR needed to recover the costs of Portfolio E.

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Table 88: Scenario 4 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2372	1795	1696	1489	1496	1494	1533	1518	1660	1707	1560	1531	1511	1486	1545	1656	1766	1817	1897	1938
Total Production Cost	3081	2792	2917	2957	2950	2953	3039	3039	2987	3068	2970	2894	2866	2886	2923	3067	3205	3279	3373	3448
Total System Costs	3285	3146	3486	3690	3759	3774	4017	4028	3984	4122	4172	4071	4056	4221	4279	4445	4831	4744	4861	4952
PVRR	2816	5313	7876	10387	12756	14958	17128	19143	20988	22756	24413	25909	27291	28621	29870	31072	32280	33380	34422	35406
Total Production Cost, $/kWh*	0.166	0.153	0.161	0.164	0.165	0.166	0.173	0.175	0.174	0.180	0.175	0.174	0.174	0.177	0.181	0.192	0.201	0.209	0.216	0.222
Total System Cost, $/kWh*	0.177	0.173	0.192	0.205	0.210	0.212	0.228	0.232	0.232	0.241	0.247	0.244	0.246	0.259	0.266	0.278	0.304	0.302	0.311	0.319

*Total system costs are not equivalent to tariffs.

28.5 Scenario 5- Base load with high gas fuel costs

28.5.1 Annual Capacity Contribution by Resource

Table 89 and Table 90 present information about the MW of generator and battery resource additions and retirements that occur under the Scenario 5. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

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Table 89: Capacity Addition Summary (MW) for Scenario 5

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	615	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	615
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	-	-	-	-	226
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	486	-	-	-	-	373	-	-	-	-	859
BESS, 4 HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	20
New Gas Gen.*	-	-	-	478	-	-	18	-	226	496	-	-	-	-	-	-	-	-	-	-	1218
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Total	777	2519	767	617	47	57	90	74	294	558	539	60	72	96	367	506	158	184	194	160	8136

**Includes LNG SJ, CS and Trucked.

Table 90: Scenario 5 Resource Retirements (MW)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	100	180	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**792**
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	-	380	-	360	-	-	-	-	-	-	740
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS- Controlled	-	-	3	-	-	-	-	-	-	-	-		-		-	-	-	-	-	-	3
Total	-	63	87	-	792	300	100	182	474	-	-	675	55	360	-	-	2	2	-	-	3092

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.5.2 Energy Production by Fuel or Resource

Table 91 provides details on the source of energy production by fuel type and resource for Scenario 5.

Table 91: Scenario 5 Energy Production by Fuel or Resource (GWh)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3153	3394	3144	3138	3163	3108	3107	3144	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	1746	87	16	0	10	16	26	16	21	9	5	14	3	18	5	5	7	6	5	4
Fuel Oil	2328	707	438	23	132	62	11	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	5197	3936	3937	4105	4176	4204	4327	4282	4345	3799	4302	4270	4208	3948	3964	4327	4080	3919	3470	2909
LNG-SJ	3818	3669	3166	5743	5693	5660	5478	5201	7833	8556	7556	7368	7347	7341	6719	4973	4552	3961	3658	3539
Hydro	23	67	149	149	149	177	178	178	177	177	178	178	177	177	178	178	177	177	178	178
UPV	398	740	854	946	945	944	944	943	898	900	899	842	725	726	725	728	725	725	726	726
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
LNG - Trucked	598	199	660	65	549	459	352	298	462	72	384	331	296	232	80	473	243	101	60	4
Biodiesel	0	0	0	0	0	0	0	0	0	0	17	24	7	40	530	1219	1901	2434	2908	3306
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1263	1263	1266	1262	1263	1262	1267	1263	1258	1260	1263
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	347	426	511	667	751	729	698	742	803	788	757	727	699	677	661	653	654	652	652	653
DPV	546	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1682	1842	2011	2207	2423	2668
Emergency Generator	220	3122	3065	865	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	5	6	6	7	8	10	10	14	17	21	24	27
BESS- 4 HR	7	115	154	177	186	185	176	181	195	162	210	211	206	204	201	191	207	230	271	296
BESS- Tranche 1	0	150	272	265	286	300	284	291	309	254	326	332	331	321	301	285	304	340	423	467
BESS- Tranche 2	0	0	17	36	36	36	34	37	36	28	40	41	40	36	35	32	34	41	54	60
BESS- Tranche 4	0	0	17	38	37	35	34	35	36	29	39	40	39	38	39	35	37	41	59	62
ASAP BESS	0	97	363	318	324	313	303	309	336	287	357	355	354	347	325	316	332	368	421	461
DBESS	8	9	5	12	19	28	31	35	39	44	49	55	60	67	76	84	88	95	100	106

28.5.3 Annual Emissions by Resource

Table 92 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 92: Scenario 5 Annual Emissions by resource (tonCO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	1684817	84179	14297	51	8806	14513	24769	14793	19390	8124	4867	12871	2452	17343	4144	4631	5958	5292	4676	3975
Fuel Oil	3488268	791881	426494	25174	157840	60482	11218	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	4747443	5700546	5521065	4849554	4615229	4583495	4505270	4323866	5881985	5433706	5283526	5140305	5078701	4905788	4540467	4351204	3901407	3461735	3087662	2735431
Biodiesel	0	0	0	0	0	0	0	0	0	0	13842	17466	5581	32395	405833	723080	1121409	1437194	1707782	1952176

28.5.4 Annual Fuel Consumption by Fuel Type

Table 93 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 93: Scenario 5 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	20,666	1,033	175	1	108	178	304	181	238	100	92	194	40	264	599	945	1,175	1,124	897	528
Fuel Oil	42,137	9,566	5,152	304	1,907	731	136		-	-	-	-	-	-	-	-	-	-	-	-
LNG	81,169	97,464	94,396	82,915	78,908	78,366	77,028	73,927	100,566	92,902	90,334	87,886	86,832	83,876	77,630	74,394	66,704	59,187	52,791	46,769
Biodiesel											138	178	58	346	4,438	7,995	12,675	16,598	20,142	23,504

28.5.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 94 shows the cost components of Scenario 5 each year during the planning period, and it indicates the total PVRR needed to recover the costs of Portfolio F.

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Table 94: Scenario 5 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2449	1949	1894	1653	1668	1672	1689	1689	1923	1816	1766	1737	1711	1695	1768	1878	1940	1964	2003	2060
Total Production Cost	3158	2945	3114	3121	3122	3132	3177	3193	3241	3185	3165	3090	3057	3025	3132	3259	3348	3395	3464	3556
Total System Costs	3362	3299	3683	3854	3931	3952	4012	4038	4159	4224	4216	4115	4095	4081	4277	4426	4762	4648	4741	4848
PVRR	2882	5501	8209	10832	13309	15616	17783	19803	21730	23541	25215	26729	28123	29409	30658	31854	33046	34123	35140	36103
Total Production Cost, $/kWh*	0.170	0.162	0.172	0.173	0.174	0.176	0.180	0.184	0.188	0.187	0.187	0.185	0.186	0.186	0.194	0.204	0.210	0.216	0.222	0.229
Total System Cost, $/kWh*	0.181	0.181	0.203	0.214	0.219	0.222	0.228	0.232	0.242	0.247	0.249	0.247	0.249	0.251	0.265	0.277	0.299	0.296	0.304	0.313

*Total system costs are not equivalent to tariffs.

28.6 Scenario 6- Base load with high gas fuel costs and high gas capital costs

28.6.1 Annual Capacity Contribution by Resource

Table 95 and Table 96 present information about the MW of generator and battery resource additions and retirements that occur under the Scenario 6. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 95: Capacity Addition Summary (MW) for Scenario 6

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS-Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR				1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	615	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	615
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	-	-	-	-	-	226
Biodiesel Conversions											226				172	373					771

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
BESS, 6 HR	-	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	20
New Gas Gen.*	-	-	-	478			373			226				35	-	-	-	-	-	-	1112
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2519	767	617	47	57	445	74	68	288	279	60	72	377	293	506	158	184	194	160	7942

*Includes LNG SJ, CS and Trucked.

Table 96: Scenario 6 Resource Retirements (MW)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	165	-	-	-	100	-	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	100	180	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-				-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	586	-	-	-	552	373	-	-	-	-	1511
UPV	-	-	-	-		-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS-Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	-	63	87	-	792	300	265	182	474	-	686	30	55	-	552	373	2	2	-	-	3863

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.6.2 Energy Production by Fuel or Resource

Table 97 provides details on the source of energy production by fuel type and resource for Scenario 6.

Table 97: Scenario 6 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
Coal	3153	3393	3144	3139	3163	3108	3058	3101	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	1744	89	16	0	10	18	7	13	22	6	15	7	7	9	4	6	7	6	10	4
Fuel Oil	2320	698	439	22	128	62	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	5202	3933	3939	4110	4165	4185	3587	3406	4206	3804	3955	4120	3990	3938	3878	3880	3807	3840	3367	2809
LNG-SJ	3827	3677	3165	5747	5700	5666	6537	6361	8177	8101	7990	7671	7640	7479	6872	5795	4998	4117	3790	3642
Hydro	23	67	149	149	149	177	177	177	177	177	177	178	177	177	177	178	177	177	177	178
UPV	398	740	854	946	945	944	942	940	898	900	899	844	724	726	725	728	724	725	726	726
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
LNG - Trucked	600	199	660	64	556	468	109	52	256	529	271	199	210	140	27	95	67	25	27	4
Biodiesel	0	0	0	0	0	0	0	0	0	0	20	3	8	6	531	1219	1901	2433	2904	3307
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1261	1263	1262	1267	1262	1259	1261	1263
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	347	426	511	667	751	729	697	741	803	788	757	727	699	677	660	653	654	652	653	649
DPV	546	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1683	1842	2011	2207	2423	2667
Emergency Generator	220	3128	3062	857	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	1	6	7	7	8	11	3	14	17	21	26	26
BESS- 4 HR	8	116	156	175	184	186	156	160	187	175	186	199	194	186	210	180	182	219	257	283
BESS- Tranche 1	0	147	272	266	286	299	245	248	289	273	291	309	309	296	326	283	291	346	422	461
BESS- Tranche 2	0	0	18	35	37	36	28	29	36	34	35	38	38	35	40	33	34	41	53	58
BESS- Tranche 4	0	0	17	37	38	35	30	30	35	33	35	38	37	34	40	32	34	40	56	64
ASAP BESS	0	98	365	317	322	310	277	282	320	300	324	333	328	324	349	317	329	372	424	453
DBESS	8	9	5	12	19	28	31	35	40	44	49	55	59	68	75	85	89	95	100	106

28.6.3 Annual Emissions by Resource

Table 98 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 98: Scenario 6 Annual Emissions by resource (CO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	1682801	86448	14442	178	8763	17324	6013	12051	20784	5907	14381	6431	6914	8034	3165	5568	6300	5258	9516	4001
Fuel Oil	3486178	786073	426268	24447	153000	60229	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	4752702	5703804	5521764	4848205	4618060	4580445	4314023	4133840	5423521	5370619	5225634	5110650	5036203	4904587	4537854	4284754	3870283	3449916	3079955	2733231
Biodiesel	0	0	0	0	0	0	0	0	0	0	22287	44670	47420	379284	862727	1362055	1850217	2268443	2640881	2936132

28.6.4 Annual Fuel Consumption by Fuel Type

Table 99 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 99: Scenario 6 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	20,641	1,060	177	2	107	213	74	148	255	72	219	85	100	108	735	976	1,204	1,136	954	542
Fuel Oil	42,112	9,496	5,149	295	1,848	728	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	81,259	97,520	94,408	82,891	78,957	78,314	73,758	70,678	92,728	91,823	89,345	87,379	86,106	83,855	77,585	73,258	66,172	58,984	52,659	46,731
Biodiesel	-	-	-	-	-	-	-	-	-	-	180	32	84	65	5,633	8,173	12,957	16,792	20,092	24,134

28.6.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 100 shows the cost components of Portfolio G each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 6.

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Table 100: Scenario 6 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2449	1949	1894	1653	1668	1673	1630	1639	1784	1800	1762	1725	1707	1682	1822	1879	1950	1973	2004	2092
Total Production Cost	3158	2945	3114	3120	3122	3133	3121	3145	3096	3147	3090	3070	3044	3048	3181	3254	3351	3397	3460	3581
Total System Costs	3362	3299	3684	3854	3931	3953	4095	4129	4088	4195	4147	4102	4090	4209	4363	4458	4803	4688	4774	4912
PVRR	2883	5501	8209	10832	13309	15616	17828	19893	21787	23587	25234	26742	28134	29461	30735	31940	33142	34228	35252	36228
Total Production Cost, $/kWh*	0.170	0.162	0.172	0.173	0.174	0.176	0.177	0.181	0.180	0.184	0.183	0.184	0.185	0.187	0.197	0.204	0.211	0.216	0.222	0.231
Total System Cost, $/kWh*	0.181	0.181	0.203	0.214	0.219	0.223	0.233	0.238	0.238	0.246	0.245	0.246	0.248	0.259	0.271	0.279	0.302	0.298	0.306	0.317

*Total system costs are not equivalent to tariffs.

28.7 Scenario 7- Flex Run of Core B (Scenario 2) run under Scenario 1 conditions

28.7.1 Annual Capacity Contribution by Resource

Table 101 and Table 102 present information about the MW of generator and battery resource additions and retirements that occur under Scenario 7. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 101: Scenario 6 System Costs and PVRR

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	559	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	559
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	452	-	-	-	373	-	-	-	373	-	1,198
BESS, 4 HR	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
New Gas Gen.*	-	-	-	478	-	860	-	-	-	-	-	-	-	408	-	-	-	-	-	-	1,746
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2463	827	617	47	917	72	74	68	62	505	60	72	504	494	133	158	184	567	160	8761

*Includes LNG SJ, CS and Trucked.

Table 102: Scenario 7 Resource Retirements (MW)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	165	-	-	-	100	-	-	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	280	-	-		-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	360	-	-	-	452	-	-	-	753	-	-	-	373	-	1938
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS- Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	-	63	87	-	792	465	640	2	474	100	452	30	55	-	753	-	2	2	373	-	4290

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.7.2 Energy Production by Fuel or Resource

Table 103 provides details on the source of energy production by fuel type and resource. There is notable growth in the generation of energy by biodiesel, which is 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 103: Scenario 7 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
Coal	3124	3379	3144	3113	3139	1406	1582	2050	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	1736	76	15	1	9	4	9	4	8	9	11	6	6	7	3	4	4	4	8	7
Fuel Oil	2312	509	148	3	60	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
LNG – EcoElec and CS	5198	3953	3949	4079	4159	4330	4219	3949	4583	4379	3944	4160	4045	5323	3883	3326	2839	2249	3494	2909
LNG-SJ	3859	3859	3415	5771	5790	7721	7450	6920	8017	8017	8066	7649	7629	6164	6846	6409	6032	5711	3654	3515
Hydro	23	67	149	149	149	177	177	177	177	177	177	178	177	176	177	178	177	177	177	178
UPV	398	740	854	946	945	944	944	942	898	900	899	844	725	721	724	725	719	722	725	726
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
LNG - Trucked	606	232	710	70	564	20	29	13	35	22	212	186	171	59	36	45	13	8	21	5
Biodiesel	0	0	0	0	0	0	0	0	0	0	18	1	4	14	532	1225	1908	2442	2908	3308
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1261	1257	1262	1265	1258	1254	1260	1264
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	346	426	511	667	751	728	698	742	803	788	757	727	699	676	660	650	652	654	653	653
DPV	546	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1683	1842	2011	2207	2424	2668
Emergency Generator	225	3109	3046	897	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	0	6	6	7	8	10	12	14	14	21	25	27
BESS- 4 HR	7	120	178	185	210	157	173	195	164	165	211	228	225	180	241	225	219	223	277	298
BESS- Tranche 1	0	155	270	241	272	200	223	252	221	219	277	306	296	202	294	275	264	283	344	384
BESS- Tranche 2	0	0	15	32	34	23	26	30	26	25	31	36	35	27	37	34	34	36	43	49
BESS- Tranche 4	0	0	16	34	35	24	27	30	26	25	34	38	35	27	38	35	35	37	43	52
ASAP BESS	0	99	349	290	309	233	256	286	258	259	317	333	326	261	333	318	317	324	385	413
DBESS	8	9	5	12	19	28	31	35	40	44	49	54	59	68	76	84	89	95	101	106

Annual Emissions by Resource

Table 104 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 104: Scenario 7 Annual Emissions by resource (tonCO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	1674889	72482	13742	840	7913	3470	7893	3851	6937	8680	10398	6070	5530	6397	2580	4047	3713	3401	7573	5924
Fuel Oil	3474335	604101	144650	5682	86974	2385	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	4776404	5852435	5705835	4875829	4671683	5290228	5061052	4625040	5540991	5448825	5222912	5118151	5044064	4770345	4531033	4089444	3695698	3289594	3071485	2724951
Biodiesel	0	0	0	0	0	0	0	0	0	0	16719	1044	4697	13564	324295	736211	1137084	1427377	1706634	1927462

28.7.3 Annual Fuel Consumption by Fuel Type

Table 105 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 105: Scenario 7 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	20,544	889	169	10	97	43	97	47	85	106	167	77	76	100	470	954	1,163	1,094	932	546
Fuel Oil	41,969	7,297	1,747	69	1,051	29														
LNG	81,664	100,061	97,555	83,364	79,873	90,449	86,531	79,076	94,736	93,161	89,298	87,507	86,240	81,560	77,469	69,919	63,187	56,243	52,514	46,589
Biodiesel											166	11	49	145	3,546	8,140	12,852	16,484	20,129	23,207

28.7.4 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 106 shows the cost components of Scenario 7 each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 7.

Table 106 includes the production costs of the system each year, including include 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 106 is equal to the sum of the production costs and the fixed costs.

Table 106: Scenario 7 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2371	1795	1696	1489	1495	1500	1498	1474	1564	1585	1564	1530	1510	1486	1546	1659	1771	1819	1894	1935
Total Production Cost	3080	2791	2919	2959	2952	2985	2962	2975	2871	2900	2901	2884	2857	2880	2918	3064	3204	3275	3364	3440
Total System Costs	3284	3145	3513	3717	3785	4101	4086	4111	4015	4024	4033	3991	3977	4137	4196	4364	4752	4662	4774	4866
PVRR	2816	5312	7894	10424	12809	15202	17410	19466	21326	23051	24653	26121	27475	28779	30004	31183	32372	33452	34477	35443
Total Production Cost, $/kWh*	0.166	0.153	0.161	0.164	0.165	0.168	0.168	0.171	0.167	0.170	0.171	0.173	0.174	0.177	0.181	0.192	0.201	0.208	0.216	0.222
Total System Cost, $/kWh*	0.177	0.173	0.194	0.206	0.211	0.231	0.232	0.236	0.233	0.236	0.238	0.239	0.242	0.254	0.260	0.273	0.299	0.296	0.306	0.314

*Total system costs are not equivalent to tariffs.

28.8 Scenario 8- Flex Run Core Portfolio A (Scenario 1) run under Scenario 2 conditions

28.8.1 Annual Capacity Contribution by Resource

Table 107 and Table 108 present information about the MW of generator and battery resource additions and retirements that occur under Scenario 8. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 107: Capacity Addition Summary (MW) for Scenario 8

-Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	559	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	559
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	452			373			344	373			1,542
BESS, 4 HR	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60
New Gas Gen.*	-	-	-	478	-	478	296	-	226	-	-	-	-	-	373	-	-	-	-	-	1,851

-Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2463	827	617	47	535	368	74	294	62	505	60	72	469	494	133	502	557	194	160	9210

*Includes LNG SJ, CS and Trucked.

Table 108: Capacity Addition Summary (MW) for Scenario 8

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	-	-	-	280	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	452	-	-	733	380	-	172	373	-	-	2110
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS-Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	0	63	87	0	792	300	0	2	474	545	452	30	55	733	380	0	174	375	0	0	4462

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.8.2 Energy Production by Fuel or Resource

Table 109 provides details on the source of energy production by fuel type and resource. There is notable growth in the generation of energy by biodiesel, which is contributing to progress toward the RPS target. The table also shows the contribution of various renewable generation sources to the overall energy production mix.

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Table 109: Scenario 8 Energy Production by Fuel or Resource (GWh)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3182	3380	3144	3138	3163	2668	2651	2719	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	2197	166	75	4	59	7	10	7	6	5	5	6	3	8	10	8	7	11	8	8
Fuel Oil	2424	918	595	31	212	2	2	2	6	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	5488	3979	3925	4063	4390	4062	4567	4579	5111	5026	4710	4687	4635	5503	7165	6826	6156	4080	3916	3598
LNG-SJ	4115	4332	3773	6215	6357	8180	7685	7403	9386	9382	9055	9051	9088	6827	5252	4565	4279	5348	4615	4123
Hydro	22	67	149	149	149	178	177	178	177	177	177	178	177	177	177	178	177	177	177	178
UPV	397	740	854	946	945	944	944	942	898	900	899	844	725	726	725	727	724	726	725	724
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
LNG - Trucked	662	371	946	200	1134	240	95	65	98	91	643	576	585	1395	157	118	57	58	49	25
Biodiesel	0	0	0	0	0	0	0	0	0	0	23	10	4	407	1368	2223	3065	3780	4428	4992
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1262	1264	1262	1267	1262	1262	1260	1259
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	346	426	511	667	751	729	698	742	803	788	757	727	699	677	661	652	654	654	653	650
DPV	543	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1683	1842	2010	2207	2423	2668
Emergency Generator	248	3416	3428	1836	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	0	6	6	7	8	4	6	14	17	21	25	23
BESS- 4 HR	7	138	192	214	236	205	186	200	184	179	225	227	223	217	212	234	235	226	251	291
BESS- Tranche 1	0	151	273	263	317	278	241	268	245	245	301	309	300	294	285	318	320	306	341	407
BESS- Tranche 2	0	0	19	41	41	31	29	33	29	27	37	37	35	35	34	37	38	35	41	54
BESS- Tranche 4	0	0	19	42	46	32	29	31	27	27	37	37	36	37	36	38	42	37	43	57
ASAP BESS	0	109	373	326	355	305	272	302	268	263	333	330	331	326	321	350	348	342	377	418
DBESS	8	9	5	12	19	28	31	35	39	44	49	54	61	68	76	84	89	95	100	106

28.8.3 Annual Emissions by Resource

Table 110 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 110: Scenario 8 Annual Emissions by resource (CO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	2134721	156159	69130	3920	57154	6881	9062	6703	5754	4336	4284	5095	2888	7518	9101	7406	6725	9990	7635	7597
Fuel Oil	3669689	1015721	579495	33346	257072	2361	1957	2446	6300	0	0	0	0	0	0	0	0	0	0	0
LNG	5047939	6426279	6291143	5720956	5374653	5360838	5386001	5213869	6602283	6567995	6367478	6312300	6302470	6450078	5391592	4892324	4436694	4163656	3739565	3349000
Biodiesel	0	0	0	0	0	0	0	0	0	0	21132	9702	4266	246174	817243	1312206	1812848	2236357	2598745	2907939

28.8.4 Annual Fuel Consumption by Fuel Type

Table 111 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 111: Scenario 8 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	26,184	1,915	848	48	701	84	111	82	71	53	102	83	43	485	1,216	1,703	1,864	1,771	1,371	808
Fuel Oil	44,329	12,270	7,000	403	3,105	29	24	30	76											
LNG	86,306	109,872	107,562	97,813	91,892	91,656	92,086	89,143	112,882	112,295	108,867	107,924	107,756	110,279	92,182	83,646	75,856	71,188	63,937	57,259
Biodiesel											210	99	45	2,631	8,936	14,509	20,491	25,827	30,651	35,012

28.8.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 112 shows the cost components of Portfolio I each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 8.

Table 112 includes the production costs of the system each year, including include 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 112 is equal to the sum of the production costs and the fixed costs.

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Table 112: Scenario 8 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
Variable Production Costs ($M)	2581	2014	1919	1668	1688	1607	1654	1657	1816	1855	1839	1830	1827	2006	1992	2130	2285	2429	2510	2583
Total Production Cost ($M)	3290	3010	3142	3138	3144	3092	3187	3231	3207	3207	3214	3225	3215	3366	3369	3540	3723	3873	3985	4093
Total System Costs ($M)	3494	3364	3736	3896	3978	4089	4283	4337	4386	4365	4380	4366	4370	4538	4666	4859	5290	5279	5414	5538
PVRR ($M)	2996	5666	8411	11063	13569	15955	18269	20439	22470	24342	26082	27687	29175	30606	31968	33281	34605	35828	36989	38089
Total Production Cost, $/kWh	0.166	0.153	0.160	0.161	0.161	0.159	0.165	0.168	0.167	0.168	0.168	0.170	0.170	0.179	0.180	0.189	0.199	0.208	0.215	0.221
Total System Cost, $/kWh	0.176	0.171	0.191	0.199	0.204	0.211	0.222	0.226	0.229	0.228	0.229	0.230	0.231	0.241	0.249	0.260	0.283	0.284	0.292	0.300

28.9 Scenario 9- Flex run of Core A under low load conditions

28.9.1 Annual Capacity Contribution by Resource

Table 113 and Table 114 present information about the MW of generator and battery resource additions and retirements that occur under the Scenario 9. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 113: Capacity Addition Summary (MW) for Scenario 9

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	615	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	615

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Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36	136	-	70	242
BESS, 4 HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Gas Gen.*	-	-	-	478	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	548
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2519	767	617	47	57	142	74	68	62	53	60	72	96	121	133	194	320	194	230	6603

Table 114: Scenario 9 Resource Capacity Retirements (MW)

-Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	130	-	-	-	100	-	-	-	-	-	-	-	-	-	-	377
Fuel Oil	-	-	-	-	-	300	280	-	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	-	-	-	740	-	-	-	-	-	-	740
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS-Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	0	63	87	0	792	430	280	2	474	100	0	30	55	740	0	0	2	2	0	0	3057

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.9.2 Energy Production by Fuel or Resource

Table 115 provides detail on the source of energy production by fuel type and resource for Scenario 9.

Table 115: Scenario 9 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
Coal	3060	3388	3143	2738	2668	2414	2388	2444	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	1230	44	2	0	7	8	10	5	9	4	4	2	1	7	1	2	2	1	1	1
Fuel Oil	2211	188	30	0	9	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	4722	3889	4017	4018	3913	3861	3936	3862	4238	3919	3990	4081	3956	3633	3232	2666	2343	1765	1186	630
LNG-SJ	3548	3237	2896	5023	4799	4763	4361	3897	5262	5130	4682	4183	3904	3711	3633	3634	3503	3525	3432	3417
Hydro	27	67	149	149	149	177	178	177	177	177	177	178	177	175	175	178	176	177	177	177
UPV	400	740	854	946	944	944	944	943	898	900	899	844	725	725	723	726	721	725	721	698
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	269
Landfill	15	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
LNG - Trucked	525	129	299	24	209	153	103	40	178	164	124	93	86	76	37	34	18	6	2	3
Biodiesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	15	114	183
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1262	1263	1262	1266	1261	1261	1246	1214
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	324	426	511	667	751	729	698	742	803	788	757	727	699	674	661	653	653	644	644	625
DPV	555	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1683	1842	2010	2207	2417	2653
Emergency Generator	187	2627	2268	256	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	5	6	8	7	8	11	4	14	17	21	25	27
BESS- 4 HR	6	123	172	155	165	165	169	189	175	182	189	214	211	220	221	246	259	284	342	370
BESS- Tranche 1	0	158	306	249	254	256	265	293	282	278	299	333	334	351	364	382	405	456	557	621
BESS- Tranche 2	0	0	19	32	32	29	32	36	33	33	34	42	39	42	43	48	54	58	72	83

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
BESS- Tranche 4	0	0	20	34	32	29	32	33	33	33	34	40	39	42	43	47	54	62	78	104
ASAP BESS	0	108	390	274	299	275	301	328	308	319	330	359	361	378	384	414	422	461	560	595
DBESS	8	9	5	12	19	28	31	35	40	44	48	55	60	68	76	85	89	94	100	105

28.9.3 Annual Emissions by Resource

Table 116 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 116: Scenario 9 Annual Emissions by resource (CO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	1174698	43498	1771	33	6521	7570	9354	4231	8538	3331	3453	1949	1058	6325	664	1676	1370	532	548	461
Fuel Oil	3184170	247288	30237	2352	22525	7152	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	4383442	5101256	4728487	4094609	3897379	3828467	3656039	3372566	4263432	4040282	3842451	3634850	3445951	3195241	2945153	2678847	2465964	2192663	1877792	1610459
Biodiesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2627	11972	88106	156502

28.9.4 Annual Fuel Consumption by Fuel Type

Table 117 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 117: Scenario 9 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	14,409	534	22	0	80	93	115	52	105	41	42	24	13	78	8	21	19	15	50	44
Fuel Oil	38,464	2,987	365	28	272	86														
LNG	74,945	87,218	80,845	70,007	66,635	65,457	62,509	57,662	72,893	69,078	65,696	62,146	58,917	54,630	50,354	45,801	42,161	37,489	32,105	27,535
Biodiesel																	30	138	1,039	1,884

28.9.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 118 shows the cost components of Scenario 9 each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 9.

Table 118 includes the production costs of the system each year, including include 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 118 is equal to the sum of the production costs and the fixed costs.

Table 118: Scenario 9 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2109	1567	1467	1304	1287	1272	1256	1225	1267	1245	1216	1160	1101	1061	1001	966	927	868	825	790
Total Production Cost	2818	2563	2688	2771	2741	2719	2711	2717	2531	2516	2519	2479	2412	2320	2286	2279	2265	2226	2211	2208
Total System Costs	3022	2917	3257	3505	3550	3539	3562	3578	3401	3366	3377	3313	3258	3183	3170	3185	3419	3219	3227	3240
PVRR	2591	4906	7300	9686	11923	13988	15912	17702	19278	20721	22062	23280	24390	25393	26318	27179	28035	28781	29473	30117
Total Production Cost, $/kWh*	0.165	0.155	0.164	0.172	0.173	0.176	0.179	0.185	0.178	0.182	0.187	0.190	0.192	0.192	0.196	0.202	0.207	0.210	0.218	0.225
Total System Cost, $/kWh*	0.177	0.176	0.199	0.217	0.225	0.229	0.236	0.244	0.239	0.243	0.251	0.254	0.260	0.263	0.271	0.282	0.312	0.304	0.317	0.330

*Total system costs are not equivalent to tariffs.

28.10 Scenario 10- Flex Run Core Portfolio A (1) run under High Cost & High Load (Stress) Conditions

28.10.1 Annual Capacity Contribution by Resource

Table 119 and Table 120 present information about the MW of generator and battery resource additions and retirements that occur under the Scenario 10. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 119: Capacity Addition Summary (MW) for Scenario 10

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200

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Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
ASAP BESS, Phase 1 and 2	-	559	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	559
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	-	-	-	-	226
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	-	226		190	373			373			1,162
BESS, 4 HR	-	-	60	-	-	-	296	-	-	53	373	-	-	373	-	-	-	-	-	-	1,155
New Gas Gen.*	-	-	-	478	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	478
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2463	827	617	47	57	368	74	68	115	426	286	72	659	720	133	158	557	194	160	8778

Table 120: Scenario 10 Resource Capacity Retirements (MW)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	-	-	-	-	100	165	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	-	300	-	-	280	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	_	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	50	226	-	550	753	-	-	373	-	-	1952
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS- Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	0	63	87	0	792	0	300	2	474	280	150	421	55	550	753	0	2	375	0	0	4304

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.10.2 Energy Production by Fuel or Resource

Table 121 provides detail on the source of energy production by fuel type and resource for Scenario 10.

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Table 121: Scenario 10 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
Coal	3177	3388	3143	3138	3163	3101	3031	3116	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	2199	162	78	4	62	29	10	6	18	19	8	9	11	15	6	8	10	8	12	11
Fuel Oil	2426	924	594	31	211	44	8	3	41	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	5488	4033	3931	4056	4372	4954	4456	4462	5324	5237	4209	4694	4597	6671	7171	6838	6190	4036	3883	3589
LNG-SJ	4111	4327	3772	6216	6365	6117	7120	6863	8213	8415	9942	9068	9141	7019	5337	4623	4245	5398	4647	4133
Hydro	23	67	149	149	149	177	177	178	177	177	177	178	177	177	177	178	177	177	177	178
UPV	397	740	854	946	945	944	944	942	898	900	899	844	725	726	725	728	723	725	725	725
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	269
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
LNG - Trucked	663	372	943	198	1140	915	384	324	1021	853	268	537	554	34	73	47	64	53	39	14
Biodiesel	0	0	0	0	0	0	0	0	0	0	2	24	11	405	1366	2224	3063	3781	4433	4990
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1262	1263	1263	1267	1261	1261	1260	1260
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	347	426	511	667	751	729	698	742	803	788	757	727	699	677	661	653	651	654	653	652
DPV	543	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1550	1683	1842	2010	2207	2424	2668
Emergency Generator	249	3357	3425	1843	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	5	6	6	7	8	6	12	14	17	21	25	27
BESS- 4 HR	6	137	192	216	241	203	179	187	223	226	219	229	227	216	226	238	243	226	250	286
BESS- Tranche 1	0	158	267	261	314	267	243	253	297	303	294	311	304	298	304	318	332	303	344	414
BESS- Tranche 2	0	0	17	40	42	31	28	29	35	35	34	35	35	37	36	38	39	34	40	51
BESS- Tranche 4	0	0	19	42	44	33	29	29	35	35	34	34	37	37	39	40	43	37	40	56
ASAP BESS	0	109	372	327	354	286	272	281	325	330	315	334	331	320	334	344	363	338	375	422
DBESS	8	9	5	12	19	28	31	35	40	44	49	55	61	68	76	84	89	95	100	106

28.10.3 Annual Emissions by Resource

Table 122 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 122: Scenario 10 Annual Emissions by resource (CO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	2136518	152780	71844	3759	60329	27088	9456	5510	16668	17957	7669	7938	10074	13678	5563	7370	9219	6998	11210	10881
Fuel Oil	3670707	1030254	578839	33887	252279	42716	7687	2936	39643	0	0	0	0	0	0	0	0	0	0	0
LNG	5046392	6417413	6290370	5720388	5374594	5483119	5561986	5392205	6970345	6934100	6436352	6300203	6287351	5715042	5384586	4878086	4437779	4162196	3730680	3340766
Biodiesel	0	0	0	0	0	0	0	0	0	0	2440	21294	11892	379510	830107	1331308	1827972	2243281	2606449	2909720

28.10.4 Annual Fuel Consumption by Fuel Type

Table 123 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 123: Scenario 10 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	26,206	1,874	881	46	740	332	116	68	204	220	100	142	145	774	1,190	1,726	1,910	1,739	1,418	848
Fuel Oil	44,341	12,445	6,992	409	3,047	516	93	35	479											

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
LNG	86,280	109,721	107,549	97,804	91,891	93,747	95,095	92,192	119,174	118,555	110,045	107,717	107,497	97,712	92,062	83,402	75,874	71,163	63,785	57,118
Biodiesel											24	217	124	4,056	9,077	14,721	20,662	25,907	30,742	35,033

28.10.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 124 shows the cost components of Scenario 10 each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 10.

Table 124 includes the production costs of the system each year, including include 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 124 is equal to the sum of the production costs and the fixed costs.

Table 124: Scenario 10 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2581	2013	1920	1668	1688	1670	1722	1732	1900	1932	1859	1830	1827	1880	1995	2137	2292	2431	2514	2582
Total Production Cost	3290	3010	3143	3138	3144	3132	3232	3281	3257	3283	3249	3217	3208	3271	3370	3544	3727	3872	3986	4089
Total System Costs	3494	3364	3736	3896	3978	3977	4198	4257	4242	4269	4366	4309	4313	4520	4719	4915	5345	5329	5466	5586
PVRR	2995	5666	8412	11063	13570	15890	18158	20287	22252	24083	25817	27401	28869	30294	31672	33000	34338	35572	36745	37855
Total Production Cost, $/kWh*	0.166	0.153	0.160	0.161	0.161	0.161	0.167	0.171	0.170	0.171	0.170	0.169	0.170	0.174	0.180	0.189	0.199	0.208	0.215	0.221

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Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Total System Cost, $/kWh*	0.176	0.171	0.191	0.199	0.204	0.205	0.217	0.221	0.221	0.223	0.229	0.227	0.228	0.240	0.251	0.263	0.286	0.287	0.295	0.302

*Total system costs are not equivalent to tariffs.

28.11 Scenario 11- Flex Run Core B (2) run under High Cost and High Load (Stress) Conditions

28.11.1 Annual Capacity Contribution by Resource

Table 125 and Table 126 present information about the MW of generator and battery resource additions and retirements that occur under the Scenario 11. Combined, the information of the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

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Table 125: Capacity Addition Summary (MW) for Scenario 11

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
ASAP BESS, Phase 1 and 2	-	559	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	559
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	452	-	-	172	373	-	-	373	-	-	1370
BESS, 4 HR	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60
BESS, 6 HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	120	-	-	-	-	180
New Gas Gen.*	-	-	-	478	-	860	-	-	-	-	-	-	-	373	18	-	-	-	-	-	1729

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Regulation Only BESS**	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
Total	777	2463	827	617	47	917	72	74	68	62	505	60	72	641	572	253	158	557	194	160	9096

Table 126: Scenario 11 Resource Capacity Retirements (MW)

-Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84			165	-	-	-	100	-	-	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	280	-	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	452	-	-	532	753	-	-	373	-	-	2110
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107
DBESS-Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	-	63	87	-	792	465	280	2	474	100	452	30	55	532	753	-	2	375	-	-	4462

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.11.2 Energy Production by Fuel or Resource

Table 127 provides detail on the source of energy production by fuel type and resource for Scenario 11.

Table 127: Scenario 11 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
Coal	3,180	3,382	3,143	3,138	3,163	2,063	2,435	2,757												0
Diesel	2,198	164	83	4	63	7	6	5	9	6	9	11	10	16	13	6	6	10	10	8.21
Fuel Oil	2,422	919	591	31	209	2														0
LNG – EcoElec and CS	5,486	4,007	3,909	4,064	4,380	4,654	4,382	4,361	5,127	5,005	4,550	4,566	4,484	6,413	4,085	3,738	3,312	3,957	3,839	3496.28
LNG-SJ	4,114	4,332	3,775	6,214	6,362	8,374	8,127	7,620	9,315	9,372	9,091	9,018	9,055	7,254	8,369	7,705	7,130	5,437	4,702	4232.29
Hydro	22	67	149	149	149	177	178	178	177	177	177	178	177	177	177	178	177	177	177	177.93
UPV	397	740	854	946	945	944	944	942	898	900	899	844	725	726	725	727	724	725	726	724.5
Land Based Wind	269	268	269	269	269	268	268	268	268	268	268	270	269	269	268	269	269	268	269	268.87
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11			0
LNG - Trucked	663	372	944	196	1,139	39	52	29	156	120	765	702	739	57	114	73	72	100	50	22.38
Biodiesel											27	41	32	406	1,373	2,224	3,062	3,779	4,421	4988.8
Solar - Tranche 1	38	940	1,263	1,266	1,264	1,263	1,264	1,267	1,264	1,264	1,263	1,266	1,262	1,263	1,263	1,266	1,262	1,261	1,262	1261.07
Solar - Tranche 2			45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	106.95
CHP	347	426	511	667	751	729	698	742	803	788	757	727	699	675	661	653	651	654	650	653.14
DPV	544	652	687	731	780	841	915	1,005	1,097	1,189	1,268	1,351	1,440	1,550	1,683	1,842	2,008	2,207	2,424	2667.59
Emergency Generator	250	3,384	3,442	1,840	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0
DR	-	-	-	0	1	2	3	4	0	7	6	7	8	8	12	14	17	21	25	22.84
BESS- 4 HR	7	137	192	214	240	162	164	192	181	181	240	245	241	233	218	233	249	218	244	289.65
BESS- 6 HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	93	90	89	98	120.09
BESS- Tranche 1	-	158	270	261	320	210	211	252	241	237	332	325	325	278	290	285	302	287	312	364.97
BESS- Tranche 2	-	-	18	39	43	25	24	30	29	27	39	42	40	42	36	38	43	37	41	53.55

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
BESS-Tranche 4	-	-	19	43	44	24	25	30	28	28	40	39	39	42	38	39	47	37	40	54.57
ASAP BESS	0	109.13	370.01	326.58	354.02	236.7	244.78	281.39	261.9	269.3	351.91	356	354.28	343.45	324.09	341.71	357.02	336.29	369.72	419.18
DBESS	7.52	9.31	4.8	11.69	19.34	27.7	31.24	34.99	39.55	44.26	48.78	54.59	60.77	68.05	76.52	84.16	88.69	94.59	100.28	106.08

28.11.3 Annual Emissions by Resource

Table 128 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 128: Scenario 11 Annual Emissions by resource (CO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	2134564	155115	78779	3801	61576	6999	5103	4652	8648	5667	8560	9582	9680	15401	11996	5679	5669	8669	9046	7878
Fuel Oil	3662520	1012761	574119	33908	250641	2061	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	5048074	6426710	6290944	5720287	5373923	5829726	5555654	5231566	6602398	6560088	6339183	6274778	6271567	5709888	5374609	4880194	4441389	4163141	3734282	3339145
Biodiesel	0	0	0	0	0	0	0	0	0	0	24746	36761	29181	383535	856048	1351968	1834081	2250686	2615390	2919485

28.11.4 Annual Fuel Consumption by Fuel Type

Table 129 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 129: Scenario 11 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	26,182	1,903	966	47	755	86	63	57	106	70	163	194	173	801	1,304	1,731	1,872	1,765	1,396	814
Fuel Oil	44,242	12,234	6,935	410	3,028	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
LNG	86,309	109,880	107,559	97,802	91,880	99,673	94,987	89,446	112,884	112,160	108,383	107,282	107,227	97,624	91,892	83,438	75,936	71,179	63,846	57,091
Biodiesel	-	-	-	-	-	-	-	-	-	-	246	375	305	4,099	9,360	14,949	20,731	25,992	30,847	35,151

28.11.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 130 shows the cost components of Scenario 11 each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 11.

Table 130 includes the production costs of the system each year, including include 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 130 is equal to the sum of the production costs and the fixed costs.

Table 130: System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2580	2012	1920	1668	1687	1665	1674	1665	1816	1853	1833	1832	1830	1887	2007	2147	2296	2437	2518	2589
Total Production Cost	3288	3009	3143	3138	3144	3149	3164	3194	3151	3198	3201	3218	3211	3278	3381	3561	3737	3884	3997	4102
Total System Costs	3492	3363	3737	3896	3977	4333	4357	4397	4362	4390	4400	4393	4399	4610	4766	5015	5439	5424	5560	5681
PVRR	2994	5664	8410	11062	13568	16096	18450	20649	22670	24552	26300	27915	29413	30866	32258	33613	34974	36231	37424	38552
Total Production Cost, $/kWh*	0.166	0.153	0.160	0.161	0.161	0.162	0.164	0.166	0.164	0.167	0.168	0.169	0.170	0.174	0.180	0.190	0.200	0.209	0.216	0.222
Total System Cost, $/kWh*	0.176	0.171	0.191	0.199	0.204	0.223	0.225	0.229	0.228	0.229	0.230	0.231	0.233	0.245	0.254	0.268	0.291	0.292	0.300	0.307

*Total system costs are not equivalent to tariffs.

28.12 Scenario 12- Biodiesel is unavailable / too costly on Island

28.12.1 Annual Capacity Contribution by Resource

Table 131 and Table 132 present information about the MW of generator and battery resource additions and retirements that occur under Scenario 12. Combined, the information on the tables shows significant activity with numerous additions and retirements over the planning period. This activity is primarily driven by the ramping up of renewable energy resources to meet the RPS targets and the targeted reduction of Expected Unserved Energy levels.

Table 131: Capacity Addition Summary (MW) for Scenario 12

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
CHP	47	22	13	13	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100
DPV	146	44	16	20	23	29	33	40	44	42	37	37	42	50	60	70	80	89	99	108	1,109
DBESS- Controlled	5	1	-	5	5	6	2	3	3	3	3	4	4	5	5	5	3	4	4	4	74
DR	-	-	-	1	14	22	37	31	21	17	13	19	26	41	56	58	75	91	91	48	661
Hydro	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
Emergency Generator	198	594	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
New Genera Units (Thermal)	-	-	244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244
New Genera Units (BESS)	131	141	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430
Tranche 1, & 2 and 4 BESS	-	435	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645
Tranche 1 & 2 Solar	160	579	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	805
Solar	90	50	60	-	-	-	-	-	-	-	-	-	-	-	75	300	225	-	75	-	875

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Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
ASAP BESS, Phase 1 and 2	-	524	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	524
New Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Biodiesel Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0
BESS, 4 HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0
New Gas Gen.*	-	-	-	478	-	-	175	-	70	-	226	-	373	373	505	-	-	-	-	-	2200
New Wind	-	-	-	-	-	-	-	-	-	225	-	-	-	-	-	-	-	150	150	300	825
New Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75	75	75	300
Total	777	2428	767	517	47	57	247	74	138	287	279	60	445	469	701	433	458	409	494	535	9622

Table 132: Scenario 12 Resource Capacity Retirements (MW)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Coal	-	-	-	-	-	-	-	-	454	-	-	-	-	-	-	-	-	-	-	-	454
Diesel	-	63	84	-	-	-	-	-	-	-	100	165	-	-	-	-	-	-	-	-	412
Fuel Oil	-	-	-	-	-	300	100	180	-	-	-	-	-	-	-	-	-	-	-	-	580
Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
Emergency Generator	-	-	-	-	792	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	792
LNG Retirements*	-	-	-	-	-	-	-	-	-	-	-	-	-	360	380	-	-	-	-	-	740
UPV	-	-	-	-	-	-	-	2	20	-	-	30	55	-	-	-	-	-	-	-	107

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
DBESS-Controlled	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Total	-	63	87	-	792	300	100	182	474	-	100	195	55	360	380	-	2	2	-	-	3092

*Includes LNG SJ, EcoEléctrica and Trucked. These retirements include conversions to biodiesel. Units converted to biodiesel are listed in the Addition Summary table under the Biodiesel Conversions category.

28.12.2 Energy Production by Fuel or Resource

Table 133 provides details on the source of energy production by fuel type and resource for Scenario 12.

Table 133: Scenario 12 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
Coal	3120	3385	3144	3111	3140	3080	3049	3117	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	1736	77	12	0	12	13	11	10	29	6	5	5	8	4	2	4	5	3	6	13
Fuel Oil	2316	510	152	2	60	35	7	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG – EcoElec and CS	5201	3957	3952	4068	4165	4177	4260	4236	4677	4531	4226	4258	3945	3566	3291	2883	2483	1804	1234	714
LNG-SJ	3860	3859	3412	5770	5776	5735	5607	5273	6730	6484	7167	6948	7330	7446	7332	6944	6492	6197	5840	5416
Hydro	23	67	149	149	149	177	177	178	177	177	177	178	177	176	175	176	177	177	176	174
UPV	398	740	854	946	945	944	944	943	898	900	899	844	725	725	854	1380	1768	1768	1893	1864
Land Based Wind	269	268	269	269	269	268	268	268	268	804	805	808	805	801	801	806	805	1158	1487	2073
Landfill	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	11	0	0	0
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	252	503	751	992
LNG - Trucked	605	232	709	69	569	464	365	299	1213	890	311	242	33	21	8	3	5	6	5	6
Biodiesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar - Tranche 1	38	940	1263	1266	1264	1263	1264	1267	1264	1264	1263	1266	1262	1263	1262	1267	1263	1262	1264	1267
Solar - Tranche 2	0	0	45	107	107	107	107	107	107	107	106	107	107	107	107	107	107	107	107	107
CHP	346	426	511	667	751	729	698	742	803	788	757	727	699	675	659	652	654	654	650	653
DPV	546	652	687	731	780	841	915	1005	1097	1189	1268	1351	1440	1551	1683	1841	2009	2201	2333	2391
Emergency Generator	225	3097	3044	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	1	2	3	4	5	6	6	7	8	9	5	14	14	21	25	27

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
BESS- 4 HR	7	118	153	165	182	179	164	169	174	188	175	178	193	174	187	226	252	270	321	368
BESS- Tranche 1	0	154	272	249	275	280	257	260	273	294	275	284	306	272	288	366	405	432	515	623
BESS- Tranche 2	0	0	17	33	36	32	31	32	33	34	32	34	33	32	34	43	48	55	65	83
BESS- Tranche 4	0	0	17	36	37	33	32	32	32	36	33	34	35	34	35	41	51	56	72	98
ASAP BESS	0	101	362	297	323	305	296	296	301	322	308	315	333	302	318	393	422	451	532	593
DBESS	8	9	5	12	19	28	31	35	39	44	49	55	60	68	76	85	89	94	100	105

28.12.3 Annual Emissions by Resource

Table 134 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 134: Scenario 12 Annual Emissions by resource (CO2eq)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	1675843	73478	11258	190	10824	12428	10333	9321	27479	5291	4690	4198	6951	3502	2008	3718	4457	2553	6082	14464
Fuel Oil	3474719	602901	149123	5274	88277	34034	6709	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	4777753	5849419	5705195	4879203	4670204	4617107	4552371	4345981	5821840	5423131	5425305	5272075	4836488	4668948	4476781	4135710	3749090	3301908	2878952	2462678
Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

28.12.4 Annual Fuel Consumption by Fuel Type

Table 135 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 135: Scenario 12 Annual Fuel consumption by Fuel Type (BBtu)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Diesel	20,556	901	138	2	133	152	127	114	337	65	58	51	85	43	25	46	55	31	75	177

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Fuel Oil	41,974	7,283	1,801	64	1,066	411	81	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	81,687	100,010	97,544	83,421	79,848	78,940	77,834	74,305	99,538	92,721	92,758	90,139	82,691	79,827	76,541	70,710	64,100	56,454	49,222	42,105
Biodiesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

28.12.5 Cash-Flow Table (PVRR)

In addition to achieving adopted targets for RPS and system reliability, minimizing costs is an important consideration for the recommended expansion planning scenario. Table 136 shows the cost components of Scenario 12 each year during the planning period, and it indicates the total PVRR needed to recover the costs of Scenario 12.

Table 136 includes the production costs of the system each year, including include 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 136 is equal to the sum of the production costs and the fixed costs.

Table 136: Scenario 12 System Costs and PVRR

Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Variable Production Costs	2372	1795	1697	1489	1496	1494	1505	1498	1635	1574	1615	1582	1457	1442	1398	1352	1278	1171	1068	970
Total Production Cost	3080	2792	2917	2957	2950	2954	3001	3009	2955	2935	3003	2972	2864	2860	2838	2828	2795	2738	2695	2672
Total System Costs	3284	3146	3486	3690	3759	3774	3884	3903	3879	3936	4071	4016	4021	4136	4292	4357	4695	4676	4875	5201
PVRR	2816	5313	7875	10387	12756	14958	17056	19009	20805	22494	24110	25587	26956	28260	29513	30690	31865	32949	33995	35028

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Cost ($M)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Total Production Cost, $/kWh*	0.166	0.153	0.161	0.164	0.165	0.166	0.170	0.173	0.172	0.172	0.177	0.178	0.174	0.176	0.176	0.177	0.176	0.174	0.173	0.172
Total System Cost, $/kWh*	0.177	0.173	0.192	0.205	0.210	0.212	0.221	0.225	0.225	0.231	0.241	0.241	0.244	0.254	0.266	0.273	0.295	0.297	0.312	0.335

*Total system costs are not equivalent to tariffs.

Exhibit 2