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2018-2019***

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Introduction and Summary of Conclusions

1.1 Introduction

Following the massive destruction resulting from hurricanes Irma and María in 2017, Puerto Rico faced the unprecedented challenge of rebuilding their electric power system. The hurricanes forced the Puerto Rico Electric Power Authority (PREPA) to rethink how its power supply and delivery infrastructure should be modified to ensure that the utility infrastructure was much better prepared for future weather events. In addition, PREPA's current fiscal situation as a debtor under the Title III of the Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA) requires it to identify a roadmap for the electrical system infrastructure that will support its path to comply with sound financial utility practices.

The development of an Integrated Resource Plan (IRP) is essential in developing a plan that would realize these goals. PREPA is required, under Puerto Rico Act 57 of May 27, 2014 (Act 57-2014), as amended, to prepare an IRP which shall consist of a detailed planning process considering all reasonable resources to satisfy the demand for electrical services over a twenty (20) year planning horizon, including resources related to energy supply and demand. In addition, the IRP shall consider resiliency, reliability, and stability of the power system, and be fully compliant with current and future environmental regulations.

This document and associated appendices present PREPA's 2019 IRP, which provides the analysis and recommendations for PREPA's energy supply resources for a 20 year period (2019 to 2038). The parts and appendices of this document are intended to fulfill the requirements of the Puerto Rico Energy Bureau (PREB) Regulation 9021, Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority (IRP Regulation). The IRP was developed by Siemens Power Technology, Inc. (Siemens) using a rigorous analytical process. The IRP analyses considered a large number of options and uncertainties, recognizing formal and informal input from PREPA and a large number of stakeholders.

The IRP recommendations are fully aligned with the five key pillars adopted by the PREPA Governing Board in its Vision for the Future of Power in Puerto Rico that we summarize below (also see Exhibit 2-2):

1. **Customer-Centric:** The IRP includes costumer participation via energy efficiency, customer side energy resources and demand response with a predominant role in the supply and consumption matrix of Puerto Rico, and empowering customers to participate and take ownership on their energy security and affordability.

2. **Financial Viability:** Within the requirements of resiliency and reliability, the plan minimizes the cost of supply and drastically reduces the dependence on imported fuels and the associated volatility; thus, supporting affordable rates that promote financial viability at both sides of the meter.
3. **Reliable and Resilient:** The IRP is centered on the concept of MiniGrids, defined as zones of resiliency into which the system can be segregated during and after a major weather event ensuring that the load can be served using local resources. In addition, MiniGrids must support effectively preparing, managing and timely recovery from such event.
4. **Model of Sustainability:** The IRP's implementation will transition the Puerto Rico electric system from one centered on fossil fuels to one in which renewable resources play a central, if not, the predominant role. The IRP's implementation will drastically reduce emissions, increase the penetration of renewable generation, achieve compliance with all current regulations, and position Puerto Rico for future regulations.
5. **Economic Growth Engine:** The distributed nature of the new generation resources that will have to be developed, the high levels of customer participation on the energy production and the overall reduction in the system cost are expected to result in employment opportunities and economic growth for Puerto Rico. The IRP will support a reliable and economic system that will attract economic development in Puerto Rico.

The 2019 IRP is not a classical IRP designed to identify the least cost approach to address the expected gap between future load growth and resources while maintaining a desired Planning Reserve Margin (PRM). Rather, this plan must satisfy the five pillars stated above for a system with declining load. The load served by the PREPA is expected to significantly decline over the course of this IRP's planning horizon due to a combination of expected base load reduction (driven by population and economic changes), energy efficiency gains, and demand side resources. Instead of new resources to meet load growth, this IRP is designed instead, to address the following needs:

- a) Address the impacts of an aging generation fleet that burns costly liquid fuels (mostly heavy fuel oil), that does not meet environmental regulations (e.g. MATS), has poor reliability, and is inflexible, which limits the incorporation of renewable resources.
- b) Achieve a reduction of cost of supply by incorporating renewable resources which will provide a permanent reduction in expensive and volatile fuel costs, trading this off by effective capital investments.
- c) Achieve compliance with the Renewable Portfolio Standard (RPS) mandate. However, Siemens observed that the renewable cost benefits alone justified greater levels of penetration and, consequently, making it possible to go beyond the current RPS mandates.
- d) Shift from centralized generation located in the south of the island to more decentralized generation resources distributed across the island.

In developing this IRP, Siemens worked with PREPA and the PREB to identify five Scenarios deemed worthy of analysis:

- Scenario 1** - No new natural gas (gas) delivery infrastructure added combined with expected (base case) cost and availability of renewable generation.
- Scenario 2** - Gas delivery is made available only in the north combined with expected (base case) cost and availability of renewable generation (this Scenario was dropped after the first screening).
- Scenario 3** - Gas is made available at multiple, new LNG terminals (north, east and west locations) combined with further reduction in the cost of renewable and higher renewable availability.
- Scenario 4** - Gas is made available at multiple, new LNG terminals (north, east and west locations) combined with expected (base case) cost of renewable and availability.
- Scenario 5** - Similar to Scenario 4, but with the Aguirre Offshore Gas Port as an option, larger combined cycle units and centralized Strategy 1, as described below.

In addition to the five Scenarios above, a sixth Scenario, the Energy System Modernization (ESM) plan was considered. The purpose of the ESM is to expedite the implementation of a preferred plan utilizing procurement options presented by the Public Private Partnership Authority, identify the pricing structure necessary to retain existing natural-gas fired generation in the south, consider locational alternatives for new large scale CCGTs, and ensure reliable capacity in the San Juan area. The ESM was analyzed and compared on an equal footing with the other five Scenarios described above.

The Scenarios were combined with one or more of the three different resource strategies:

- Strategy 1** - Reflects a traditional, centralized energy program with generation resources predominately located at a few centralized locations emphasizing reliability and economic metrics.
- Strategy 2** - Reflects a system of more distributed, flexible generation, emphasizing resiliency and closer proximity of generation sources to the customer. The strategy incorporates micro or MiniGrids and hardening of existing PREPA infrastructure. In this strategy, most of the load is supplied from local supply resources that can be isolated from the remainder of the grid during a major event, but still supply all or a portion of the nearby load.
- Strategy 3** - Reflects a hybrid of the first two strategies that embodies a combination of the benefits of Strategy 1 and Strategy 2. In this strategy, economies of scale are considered, which results in some of the load potentially served, under normal conditions, from remote resources. During a major event, the potential for greater levels of rotating load shed in this strategy is greater than with Strategy 2 but should also result in lower operating costs.

Siemens combined Scenarios and strategies to define the structure under which candidate portfolios of resources were assessed. To these combinations of Scenarios and strategies, Siemens added assessment of high, base and low load forecasts and several sensitivities were considered (e.g. high gas prices, high/low cost of renewable, etc.). Part 5 - Resource Needs Assessment, of this document, provides further details on the complete range of analysis.

In the development of the IRP, over 78 Long-Term Capacity Expansion (LTCE) plans were investigated to assess plausible options and numerous uncertainties, taking into account stakeholder input. These points were critical for the final product and included multiple aspects, for example: a) the timing of investments in traditional thermal generation units, b) practical limits to the ability of PREPA to effectively interconnect additional battery energy storage and renewables generation, c) uncertainty associated with fuel price forecasts and infrastructure options, d) uncertainty associated with the customer demand forecast, and d) assessment of resource candidates provided by PREPA's management and the Puerto Rico Public-Private Partnership Authority (P3). As detailed in Part 7 – Assumptions and Forecasts, this effort resulted in the identification of a final set of 34 LTCE plans that were assessed to identify the recommended resource plan with a primary focus on the next 5 years, while also considering the long-term planning horizon of 20 years. Part 8 – Resource Plan Development of this IRP provides the details of assessment and inputs of the 34 LTCE plans. A summary of the main resource additions of the 34 LTCE plans are provided in Exhibit 1-1.

The next section provides a summary of Siemens conclusions and recommendations based on the consideration of the broad array of Scenarios and all strategies represented in the 34 LTCE plans and identification of common elements among them to define the minimum regret or no regret decisions (i.e., the decision that would provide the best possible solution over the broadest range of potential future conditions). Siemens has also prepared the transmission expansion plans associated with the generation resource options, which is summarized in Appendix 1 – Transmission and Distribution Planning.

This IRP is a recommended plan for PREPA and Puerto Rico. The IRP does not address the details of procurement, interconnection, ownership, rate structures, nor the issues associated with PREPA's debt or privatization plans. All of these other important issues will need to be addressed in other processes and venues, and later combined with this IRP to develop a complete roadmap for Puerto Rico's power system.

1.2 Summary of Conclusions and Recommendations

The conclusions and minimum regret or no regret recommendations of this IRP include integrating the maximum amount of renewable generation that is practical to interconnect in the first four years of the planning period, adding distributed resources and hardening the transmission and distribution grid so that it can be segregated into eight largely self-sufficient electric islands (MiniGrids). This is essential in order to mitigate, manage and enable timely recovery from a major storm, while shifting the traditional generation from largely heavy fuel oil and distillate fuels to renewables and cleaner natural gas.

The review of the options revealed two resource plans that were deemed both low cost and most practicable, the ESM and the Scenario 4 Strategy 2 (S4S2) plan. These two plans were virtually identical in cost, with less than a \$9M or 0.06% difference in cost, as measured by net present value of cash flows (NPV).

While the S4S2 and ESM plans had a number of identical elements, they also contained differences. In order to create an action plan with no regrets or minimum regrets, Siemens recommends that PREPA implement the ESM and add preliminary activities drawn from selective elements of the S4S2. By adding elements from the S4S2, the resulting ESM plan has greater flexibility and incorporates a hedge against potential issues that may arise with the development of new resources, the continued reliance on PREPA's aging generation fleet and the changes in the future system load.

The following list provides a summary of conclusions and recommendations.

1.2.1 Supply Side Decisions and Conclusions

1. **Maximize the rate of installation of solar photovoltaic (PV) generation for the first four years (2019 to 2022) of the plan:** Siemens recommends that PREPA issue request for proposals (RFPs) for solar PV in blocks of approximately 250 MW, and depending on pricing and PREPA's capability to interconnect, continue adding blocks with a goal of interconnecting at least 720 MW and possibly 1,200 MW over the first four years of the plan. The quantity of solar PV solicited should consider PREPA's expected capability to interconnect the new renewable facilities, which will be a function of the size and number of projects determined after responses are received. In all but one LTCE plan analyzed, the installation of PV reaches the maximum allowed new solar PV capacities as defined to account for an aggressive but practical implementation limit for the first five years on the plan. The one exception is the case where the costs of renewable generation do not drop in Puerto Rico and, in this single case, only 720 MW of renewable generation is added to the system over these years. It should be noted that the development and interconnection of these large amounts of solar PV, in such a short time, is a very aggressive plan for an isolated, island-based power system.
2. **Install between 440 MW to 900 MW of Battery Energy Storage in the first four years of the plan:** The amounts of battery energy storage are heavily correlated with the total amounts of PV to be installed and the local energy supply required for the MiniGrids into which the system is expected to segregate during major events. For instance, the minimum amounts of Battery Energy Storage (BESS) observed are 440 MW for the ESM plan and 800 to 1,100 MW for the Scenario 4 and Strategy 2 (designation as S4S2) depending on the load growth. Scenario 1 with no new gas and Scenario 3 have similar levels to those observed for high load of Scenario 4 (1,240 MW max).

It is recommended that storage be added to the RFPs for renewables presented above, in blocks of 150 to 200 MW. Siemens also recommends that the RFPs for storage be combined with the RFPs for PV with the option of bidders providing either or both of these technologies. The combined RFPs give the developers the opportunity to co-locate the storage with PV and gain advantages of sharing equipment, including the inverters.

3. **Convert San Juan 5&6 Combined Cycle (CC) to burn natural gas:** This option is currently an ongoing initiative using a ship-based liquefied natural gas (LNG) terminal and was adopted as a given in the formulation of all plans where there is new gas development (all Scenarios but Scenario 1). However, initial runs of the LTCE early in the project had already identified this option as a least cost alternative (i.e. it was selected by the optimization process).
4. **Develop a land-based LNG terminal in San Juan to supply a new combined cycle gas turbine (CCGT) at Palo Seco and the existing San Juan 5&6 CCGT:** This decision is selected every time in the LTCEs, with the exception of the case where it was assumed the LNG terminal could not be developed for external reasons (Scenario 1). The CCGT was limited to a smaller unit (F-Class representative unit) or about 302 MW, to limit the size of the largest unit in the system. Larger units H-Class

of about 449 MW were selected by the LTCE runs if allowed. However, the CCGT size was limited to reduce the amount of spinning reserve generation that must be on line to respond to the potential trips of large generating units. This new CCGT should be in place as soon as practical (2025 was assumed in this study).

5. ***Install a CCGT at Costa Sur Steam Plant or extend a renegotiated contract with EcoEléctrica:*** Under all cases, unless the contract with EcoEléctrica is renegotiated to significantly reduce the fixed payments and the plant is allowed to cycle frequently, EcoEléctrica is replaced by a 302 MW CCGT after the contract expires in 2022. The analysis assumes the new CCGT can be built in 2025. Due to the inability of installing gas generation elsewhere in the system, Scenario 1 installs two or even three F-Class CCGT here over time, depending on the load.
6. ***Install new Gas Turbines (GTs) capable of burning containerized natural gas:*** The need to serve critical and priority loads within the MiniGrids resulted in the necessity to add 17 to 18 small gas turbines (each of 23 MW) at selected locations across the island. In addition, the new units will allow PREPA to retire the 18 of PREPA's existing old and unreliable Frame 5 GTs (21 MW each). The new GTs include 2 units at located at Ponce East (Jobos), 4 units at Mayagüez North (Aguadilla), 5 units at Carolina (Daguao) - 5 units at Caguas (Yabucoa) and 2 units at Cayey. Siemens found the costs of these small GTs was significantly less than the costs to the Puerto Rico economy should another large hurricane strike Puerto Rico and the MiniGrids were forced to operate in isolated mode for a month and not have enough resources to supply the critical and priority load. In the assessment, Siemens included all the resources available to the MiniGrids during grid isolated operations including the PV and storage in addition to the GTs, however we verified that there was enough thermal generation to supply the critical loads. These small GTs should be placed in service as soon as practical (2021 is assumed as the earliest commercial operation date).
7. ***Develop a Ship-Based LNG terminal at Mayagüez:*** Developing a new LNG import terminal at Mayagüez and install a large 302 MW CCGT is the least cost solution under most cases, with the exception of cases when one of the following apply: a) very low cost of renewables, b) no new gas can be developed, c) low load growth, or d) the Yabucoa LNG terminal is developed and a 302 MW CCGT as is the case of the ESM plan or if the LNG in the North is limited to the ship-based delivery. Under the balance of the Scenarios, including the Scenario 4 Strategy 2 (S4S2), the 302 MW CCGT is recommended for installation at Mayagüez by 2028 under the base and high load forecast. Under the ESM plan, the Ship-Base LNG is also developed but it is used to supply the aeroderivative gas turbines (Aeros) installed at Mayagüez that are converted to natural gas. The recommendation is to advance the development of the ship-based LNG with the view of at least converting the existing units to burn LNG initially and then develop a larger CCGT plant as the load, status of other resource developments and prices of renewables require.
8. ***Develop a Ship-Based LNG terminal at Yabucoa:*** A new LNG terminal at Yabucoa is part of the least cost solution for a number of cases such as high demand, inability to develop a land-based LNG at San Juan, and the ESM plan. Under a number of the LTCE cases, a large CCGT (302 MW) is called for at Yabucoa in conjunction with the LNG terminal, and in others a medium CCGT (150 MW) is developed. This terminal is recommended as a hedge against the potential that either of the other two LNG

terminals (San Juan and Mayagüez) is not developed. In addition, as was observed in the ESM plan, if the LNG terminal and the 302 MW CCGT are developed at Yabucoa, the cost differential with the S4S2 that develops a CCGT at Mayagüez is minimal. This Yabucoa CCGT, when part of the plan, is selected in general by 2025 (i.e. as soon as possible).

As a consequence of the investment decisions above and the expected reduction in the load, accelerated by the assumed energy efficiency gains and the increased penetration of demand side resources, most of the existing generating fleet is recommended to be retired by 2025, with the exception of the CCGTs at San Juan and Aguirre and the GTs at Cambalache and Mayagüez. It must be stressed that these retirements can only be carried out when all the conditions leading to the recommendation are in place; in particular, the new supply resources are fully operational.

1.2.2 Transmission and Distribution Decisions, Conclusions and Recommendations

Central to the IRP is developing the capability to segregate the system into eight MiniGrids for resiliency of the electrical service. The MiniGrids require the recommended generation and battery energy storage projects described above and the recommended transmission and distribution hardening projects described in Appendix 1. The recommended MiniGrids are designed to operate in grid-isolated mode following a major storm, ensuring continued supply to critical loads (those necessary to manage the recovery), and provide timely resupply to the priority loads (those required to regain normalcy and restart the economy) and balance the loads within the MiniGrid. Complementary to the MiniGrids, smaller microgrids have been identified for those areas that, due to geography and system topology, are likely to remain isolated for longer periods of time after a major event.

Under interconnected operation, no additional transmission investments were found necessary, beyond those already identified for grid hardening. This result was expected due to the shift towards distributing new generation additions across Puerto Rico and the de-emphasis of the concentration of generation in the South.

The system was also found to be stable and have appropriate frequency response even with high levels of renewable generation online, thanks to the support from the additions of battery energy storage. However, studies also identified the need to convert some of the generators slated for retirement to synchronous condensers. Preliminary analyses indicate that Palo Seco Units 3&4 and San Juan Units 7, 8, 9 and 10 are the minimum number of units that need to be converted. However, Siemens recommends that a detailed study be conducted to determine the schedule, capacity, and costs of the synchronous condenser's conversions as well defined its technical performance in support of transient voltage recovery and stability. The stability study also identified the need to conduct a study to optimize the frequency response of existing and new resources (including the storage) and the under frequency load shedding strategies.

1.2.3 Demand Side Decisions

The demand side decisions are twofold:

1. Establish an Energy Efficiency (EE) program with the objective of reducing the demand in values approximating the 2% per year, as defined in Part 3 – Load Forecast.

2. Reinforce the distribution system and enable two-way flow of energy and providing voltage regulation and flicker control to facilitate the high penetration of distributed energy, as forecasted in this IRP (see Appendix 4 – Demand-Side Resources).

Exhibit 1-1: Summary of Investment Decisions by Scenario, Strategy and Load Growth¹

Count	Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	F-Class Mayaguez 2028	F-Class Yabucoa 2025	Small CCGT (LPG/NG) North	F - Class San Juan 2029	Medium CCGT Yabucoa 2024	Peakers (small CC) 2019-2022	New Solar 2019 - 2022	BESS 2019 - 2022	New Solar 2023 - 2028	BESS 2023 - 2028	New Solar Total	BESS Total
1	S1S2B	X	✓ (2025, 2028)	X	X	X	X	X	396	1200	1200	2520	380	3720	2140
2	S1S2H	X	✓ (2025 x 2, 2033)	X	X	X	X	Palo Seco 2024	472	1200	1240	3060	120	4320	1880
3	S1S2L	X	✓ (2025, 2028)	X	X	X	X	X	303	1200	1160	2100	180	3300	1800
4	S1S3B	✓	✓ (2025, 2028)	X	X	X	X	X	343	1200	1120	2520	160	3720	1640
5	S1S3H	✓ (141 MW)	✓ (2025, 2028)	X	X	X	X	Palo Seco 2024	476	1200	940	3060	120	4260	2500
6	S1S3L	X	✓ (2025, 2028)	X	X	X	X	X	303	1200	1120	2040	20	3240	1900
7	S1S2S1B	✓ (141 MW)	✓ (2025, 2028)	X	X	X	X	X	345	1200	1120	2640	500	3840	2700
8	S1S2S2B	X	✓ (2025 x 2, 2028)	X	X	X	X	X	444	1200	1140	2820	80	4020	1800
9	S1S2S3B	✓ (S. Juan LFO)	✓ (2025)	X	X	X	X	✓ (LFO)	350	1200	1140	1140	0	2640	1560
10	S1S1B	X	✓ (2025, 2028)	X	X	X	X	X	297	1200	1160	2520	0	3720	2220
11	S3S2B	✓	✓	X	X	X	X	X	303	1500	980	2520	200	4020	2380
12	S3S2H	✓	✓	X	X	X	X	X	303	1500	1180	4560	200	4560	3260
13	S3S2L	✓ 2027	✓	X	X	X	X	X	303	1500	940	1980	240	3480	1980
14	S3S3B	✓	✓	X	X	X	X	X	303	1500	1020	2460	260	3960	3960
15	S3S3H	✓ 2027	✓	X	X	✓ (76MW)	X	✓	303	1500	1100	2880	100	4560	2220
16	S3S3L	✓ 2027	✓	X	X	X	X	X	303	1500	960	1860	260	3420	2440
17	S4S2B	✓	✓	✓	X	X	X	X	372	1200	900	1020	40	2220	1080
18	S4S2B-M	✓	✓	✓	X	X	X	X	387	1200	900	1020	40	2220	1080
19	S4S2H	✓	✓	✓	X	X	✓	✓	479	1200	800	1380	0	2580	960
20	S4S2L	✓	✓	X	X	X	X	X	280	1200	1100	900	60	2100	1160
21	S4S3B	✓	✓	✓	X	X	X	X	388	1200	900	1140	160	2340	1540
22	S4S3H	✓	✓	✓	✓	X	X	X	440	1200	1000	1380	0	2580	1420
23	S4S3L	✓	✓	X	✓ (2028)	X	X	X	280	1200	1080	720	0	1920	1080
24	S4S2S3B	✓	✓	X	X	X	X	X	303	1200	920	960	20	2160	1020
25	S4S2S4B	✓	✓ 2027	X	✓	X	X	X	327	1200	1160	1140	0	2340	1220
26	S4S2S5B	✓	✓	X	X	X	X	✓	591	1200	580	1140	80	2340	960
27	S4S2S6B	✓	✓	✓ (2025)	X	X	✓ (2028)	✓	204	720	620	0	0	780	620
28	S4S1B	✓	✓	✓	X	X	X	X	324	1200	900	1140	0	2340	1460
29	S5S1B	✓	302 + 369	X	X	X	X	X	71	1200	1020	960	0	2160	1020
30	S5S1S5B	✓	✓	X	X	X	X	X	60	1200	1060	1140	643	2340	1400
31	ESM Plan	✓	Eco Instead	X	✓	✓	X	X	418	720	440	180	140	900	800
32	ESM high	✓	Eco Instead	X	✓	✓	X	X	477	720	440	960	160	1680	780
33	ESM low	✓	Eco Instead	X	✓	✓	X	X	418	720	440	0	140	720	640
34	ESM 50% RPS	✓	Eco Instead	X	✓	✓	X	X	618	720	440	420	260	1980	820
		Strong no regret with no variation among cases that support decision being made													
		Decision common to multiple cases / little variation between scenarios that allow the decision to be taken													
		Decision common to few scenarios that allow the decision to be taken													
		Decision common to one scenario, PV / BESS: outlier or close follow up required.													

¹ See Part 5 – Resource Needs Assessment for a detailed description of the various Scenarios.

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Planning Environment

In this part Siemens documents the set of external factors that affect the environment under which PREPA is operating at the time of the IRP development. In addition to market conditions and stakeholders' input, it is important to consider the other key external factors that are in place, including applicable laws and regulations and conditions that have changed since the last IRP.

The description of this planning environment is a requirement of the IRP Regulation, which specifically requires the following:

- PREPA shall describe, at a minimum, the following factors: federal, state, or municipal standards and rules that impact the requirement for, or availability of, energy efficiency, renewable energy, fuel alternatives, or other resource requirements; and environmental standards and regulations that impact existing utility resources or resource choices at the present time and throughout the planning period.
- The Planning Environment part shall also include a discussion of substantial regulatory or legislative standards and rules that have changed since the approval of the most recent IRP.

Although there are numerous factors that have the potential to directly or indirectly impact the IRP, summarized herein are what have been identified to be the key factors warranting acknowledgement and documentation.

2.1 Environmental and Energy Standards and Regulations Applicable to PREPA

Puerto Rico is subject to most federal environmental standards applicable to energy generating facilities as well as state standards and regulations. A description of policies deemed as substantial to resource planning and how they are considered in the IRP analysis is included in Exhibit 2-1. These largely include the Environmental Protection Agency (EPA) federal air emission and water standards and Puerto Rico regulations governing energy efficiency, resource requirements, and environmental standards.

Exhibit 2-1. Environmental and Energy Standards Applicable to PREPA

Category	Law / Regulation	Summary
Federal Environmental Standards - EPA ²	Mercury and Air Toxics Standard (MATS)	The MATS rule was finalized in December 2011 and requires facility specific emission reductions of mercury, acid gases, and particulate matter. This is a command-and-control type of regulation with no allowance trading. Several PREPA facilities remain out of compliance and are required to run for reliability purposes. The IRP will inform pathways to MATS compliance for these units.
	National Ambient Air Quality Standards (NAAQS)	EPA updated attainment designations for SO ₂ based on detailed air quality monitoring in December 2017. The standard for SO ₂ is 75 parts per billion. Puerto Rico must finalize a state implementation plan (SIP) by May 2019 addressing compliance for two areas designated as nonattainment. Emissions from all generating units will be modeled and reported in the IRP analysis. The IRP will inform the SIP as PREPA units currently represent the most significant emission sources in the areas in Puerto Rico designated as nonattainment.
	Greenhouse Gas Emission Standards	The New Source Performance Standards (NSPS) for Electric Utility Generating Units was finalized in August of 2015 and sets a rate limit of 1,000lbs of CO ₂ /MWh for combined cycle natural gas plants and a limit of 1,400lbs of CO ₂ /MWh for coal plants. Units emitting above these levels are not included as new generation options due to this rule and market conditions not supporting, for example, new build coal.
	Clean Power Plan (CPP)	The final CPP under Section 111(d) of the Clean Air Act was finalized in August 2015 and required state-level emission targets by 2030. Puerto Rico was not covered under the final rule. Due to legal challenges and additional review of this rule, it is anticipated that this rule will be withdrawn in its entirety. The IRP therefore is not modeling compliance with the CPP. CO ₂ emissions are reported and are expected to show a significant decline.
Puerto Rico Energy Standards	Renewable Portfolio Standard (RPS)	Act 82 of July 19, 2010, as amended, defines specific requirements to promote energy diversification by creating an RPS (Renewable Portfolio Standard). This rule requires load serving entities to supply increasing shares of retail sales with qualified renewable and alternative sources starting at 12 percent in 2015 increasing to 15 percent in 2027 and 20 percent in 2035. PREPA has not met RPS targets to date. The IRP will target compliance beginning in 2020, depending on feasibility, and maintain compliance for the balance of the study horizon. Sensitivities considering higher RPS targets are also modeled.
	Energy RELIEF Plan – Energy Efficiency	Act 57-2014 orders PREPA to adopt Puerto Rico's RELIEF Plan, which requires that within 3 years from July 1, 2014, at least 60 percent of the electricity generated in Puerto Rico from fossil fuels is generated in a highly efficient manner, as defined by the regulations approved by the PREB. Government energy savings mandates also established under this Act include a 40 percent reduction in energy consumption by state agencies, public corporations, and judicial branch buildings by promoting energy savings performance contracts (ESPCs) unless proven not cost effective. The Legislature must reduce its electrical energy consumption 12% by 2022, from a baseline of fiscal year 2012-2013. Municipalities must reduce electricity consumption by 5% annually for three years, or 15% in the first three years. Compliance was initially expected to begin in 2016 or

² These regulations and requirements are further detailed in the environmental section of the IRP found at the end of Part 4 – Existing Resources.

Category	Law / Regulation	Summary
		<p>2017.</p> <p>The State Office of Energy Policy will oversee the development and implementation of plans and programs to fulfill this law and publish semi-annual results from program evaluations. Act 57-2014 also mandates the benchmarking of energy use and monitoring of energy efficiency measures in all public buildings, including municipalities.</p>
	Regulation on Microgrid Development	<p>The final Microgrid Regulation of May 2018 sets the legal and regulatory framework required to promote and encourage the development of microgrid systems in Puerto Rico, enable customer choice and control over their electric service, increase system resiliency, foster energy efficiency and environmentally sustainable initiatives, and spur economic growth by creating a new and emerging market for microgrid services. It intends to promote the development of Microgrid systems by enabling their implementation through different business and operational models. The Final Microgrid Regulation recognizes three main types of microgrid systems: (i) Personal Microgrids; (ii) Cooperative Microgrids and (iii) Third-Party Microgrids.</p> <p>While supporting microgrids where operationally and economically beneficial, PREPA expressed concerns with the final Microgrid regulation adopted by PREB and may seek changes.</p> <p>In the context of long term resource planning, the IRP will identify microgrids that could be owned by the utility or private entities. Moreover, if during the development of the IRP plans for a privately owned microgrid become available, this could be incorporated as an option when assessing the coverage of the MiniGrids.</p>

Source: various statutes referenced, Siemens

Additional detail on how these laws and regulations are accounted for in the IRP is included throughout the IRP report.

2.2 Laws and Regulations Changed Since Last IRP

Regulation on Integrated Resource Planning for the Puerto Rico Electric Power Authority (Regulation 9021)

The PREB adopted the Regulation 9021 on April 24, 2018. This regulation, referred to as the Regulation on Integrated Resource Plan for Puerto Rico Electric Power Authority, was enacted as required under the Act No. 83 of May 2, 1941, as amended, known as the Puerto Rico Electric Power Authority Act (Act 83 of 1941), and Act 57-2014, as amended, the Puerto Rico Energy Transformation and RELIEF Act. Regulation 9021 serves to make sure that the IRP is a useful tool to improve the system's reliability, resiliency, efficiency, and transparency, and offer electric power services at reasonable prices. Specifically, this regulation defines the required contents and organization of the IRP, the process with PREB, and performance metrics for PREPA following PREB's review and evaluation of the IRP.

Key parameters of the IRP are reflected including the defined 20-year planning period, the contents and organization of the IRP report and technical appendices, and sourcing requirements and documentation. As noted above, the requirement for documentation on the IRP planning environment is one of the required parts of the IRP. This IRP analysis also reflects the specific requirements outlined in Regulation 9021 regarding load forecasting, existing resources, resource needs determination including planning reserve margin, new

resource options including supply- and demand-side resources as well as distributed and storage resources.

To account for a range of future market conditions, Regulation 9021 specifies that the IRP shall consider multiple Scenarios that cover a reasonable range of possible outcomes for uncertain forecasts and that the IRP shall consider sufficient Scenarios to capture a wide range of possible risks and justify Scenarios included and those excluded. It is also required that a single reference case representing PREPA's best understanding of expected future conditions is included in the IRP. This Scenario is called the Base in this report.

The approach to analyze the resource options and tools used are also discussed in the requirements. Specifically, a capacity expansion model is required for the basis of the analysis. Further, sensitivity analysis of each resource plan is required. In this analysis, Siemens is using AURORAxmp® (by EPIS, now Energy Exemplar) as the long-term capacity expansion tool. Risk analysis is performed using Scenarios (high/low/base) and a number of sensitivities as discussed later in this report.

Finally, Regulation 9021 lays out the requirements for analysis of the transmission and distribution system. This will be addressed in the IRP analysis using AURORA nodal modeling, PSS®E transmission system studies and targeted distribution hardening distribution studies³.

Regulation on Microgrid Development (Regulation 9028)

The PREB adopted the Regulation 9028 on May 18, 2018. This regulation, referred to as the Regulation on Microgrid Development, sets the legal and regulatory framework required to promote and encourage the development of microgrid systems in Puerto Rico, enable customer choice and control over their electric service, increase system resiliency, foster energy efficiency and environmentally sustainable initiatives, and spur economic growth by creating a new and emerging market for microgrid services. It intends to promote the development of Microgrid systems by enabling their implementation through different business and operational models. The Final Microgrid Regulation recognizes three main types of microgrid systems: (i) Personal Microgrids; (ii) Cooperative Microgrids and (iii) Third-Party Microgrids.

While supporting microgrids where operationally and economically beneficial, PREPA expressed concerns with Regulation 9028 adopted by PREB and may seek changes.

PREPA Revitalization Act, Act 4 of 2016

On February 17, 2016, the Governor signed into law the Puerto Rico Electric Power Revitalization Act, Act 4 of 2016. The law aimed to begin restructuring for PREPA's \$9 billion debt as a means to start addressing the Commonwealth's \$70 billion debt. Under the law, the PREPA Revitalization Corporation was created. This entity would issue new bonds in exchange for PREPA bonds under a new securitization that did not close. On July 30, 2018, the Governor of Puerto Rico and the federal Financial Oversight and Management Board announced a new agreement relating to restructuring certain of PREPA's debt, which may or

³ These studies include those carried out by NYSSGC and ProsumerGrid for the Puerto Rico Grid Re-Design™ Study.

may not implicate Act 4 in one or more respects. A restructuring, if consummated, could affect PREPA's cost of capital in the IRP.

Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA)

On June 30, 2016, President Obama signed into law, the federal Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA), which would create a structure for exercising federal oversight over the fiscal affairs of territories. PROMESA would establish an Oversight Board with broad powers of budgetary and financial control over Puerto Rico. PROMESA also would create procedures for adjusting debts accumulated by the Puerto Rico government and its instrumentalities and potentially for debts of other territories. Finally, PROMESA would expedite approvals of key energy projects and other "critical projects" in Puerto Rico. On July 2017, PREPA became a Debtor under the Title III process of PROMESA. The Fiscal Plan to be approved by the Financial Oversight and Management Board (FOMB) could affect PREPA's cost of capital in the IRP. On the other hand, the results of the IRP, especially the infrastructure investments, could affect PREPA's Fiscal Plan and its debt restructuring.

Ley para Transformar el Sistema Eléctrico de Puerto Rico (Law to Transform the Electric System of Puerto Rico), Act 120-2018

On June 20, 2018, the Law to Transform the Electric System of Puerto Rico was approved for the purpose of authorizing the legal framework required for the sale, disposition or transfer of assets, operations, functions, and services of PREPA. In general, this act provides the legal framework for the privatization process of PREPA, by means of public private partnerships (PPPs) transactions, among others. Act 120-2018 also establishes the necessary safeguards to ensure a fair and transparent process and amends the Act 29-2009, as amended, known as the Public Private Partnerships Law. Transactions like generation assets sales and other assets PPPs could affect PREPA's cost of capital in the IRP.

Puerto Rico Senate Bill 1121 for creating the Puerto Rico Energy Public Policy Act

On November 6, 2018, the Senate of Puerto Rico approved its Bill 1121 for creating the Puerto Rico Energy Public Policy Act. The main purpose of the act, if approved, is to complement Act 120-2018 for the privatization process of PREPA, creating the energy public policy of Puerto Rico. This bill is currently under the consideration of the House of Representatives. If approved, the act will amend Act 83 of 1941, Act 57-2014 and Act 82-2010, among others. The amendments to these laws could affect the assumptions and Scenarios in the IRP, including the cost of capital simulated.

2.3 Solar and Energy Storage Cost Decline

Due to technology improvements, growing economies of scale, and technology maturation, costs for solar energy and battery storage have declined rapidly in recent years. This is a trend that many anticipate will continue in the coming years, particularly for larger, utility-scale solar installations that are generally seen as less mature relative to solar installations at or on residential and commercial facilities. The NREL⁴ Annual Technology Baseline (ATB) 2018 anticipates utility solar capital costs will fall at a compound annual rate of 1.5%-3% from 2018-2050. Regarding battery energy storage, an even less mature technology, many expect rapid declines due to economies of scale as adoption increases for both storage and electric

⁴ National Renewable Energy Laboratory of the federal Department of Energy

vehicle applications. In China, 332 GWh of battery manufacturing capacity have been announced by 2021.⁵ Despite this general consensus at this time for future declines in cost, the magnitude and timing of these declines are less certain. Also, as these technologies become more affordable and, consequently, their demand increases, it is uncertain how the offer and their cost will behave in the future.

Solar and solar paired with energy storage, such as lithium-ion (Li-ion) batteries, represent clean and renewable energy options for Puerto Rico that do not require the need for fuel infrastructure or volatility associated with fuel costs. Further, with additional storm hardening tactics like deeper anchoring of ground mounted solar installations, these technologies can withstand significant hurricane conditions. Battery storage technologies can produce or absorb power, providing value to utilities in managing supply to meet load throughout the day. Due to the remote location and hardening requirements, cost premiums (higher costs) for these technologies are assumed in this analysis relative to that, for example, of new solar builds in advantageous areas in the continental U.S. However, the changes in cost outlook even relative to a few years ago are reflected in this IRP analysis as well as a range of outcomes as to the timing and magnitude of these technology cost declines. Overall, however, this trend and the need for a reliable and resilient electric grid present a unique opportunity for Puerto Rico to transition to cleaner, renewable energy sources that by their distributed nature support resiliency.

It is expected that the utilities will deploy huge amounts of solar energy and battery storage, due to the decline in their costs. However, there is no precedent in the electric industry of such deployments and, consequently, there is no experience in developing projects for the simultaneous integration of very large amounts of solar energy and battery storage, in addition to no operational experience managing them. Hence, even though the development of these technologies promises to achieve these benefits, it is important to deploy them in an orderly and planned manner, so the utility is able to acquire the needed operational experience of managing a new technology which has not yet been proved at the large scale that was analyzed in this IRP.

New wind generation is also considered as a part of the IRP analysis. Although the wind technology costs are not declining as noteworthy as solar and battery storage costs, the performance of wind turbines is improving particularly at low wind speeds. This increased performance offers a lower levelized cost of energy from new wind projects. Part 7 – Assumptions and Forecasts provides further details on Siemens forecast.

2.4 Hurricane Impacts on the IRP

Even before the 2017 hurricanes, Puerto Rico's economy was in structural decline, with GNP⁶ and population falling by at least a percentage point a year. The devastation of Hurricanes María and Irma in 2017 exacerbated these trends with this event alone resulting in a 4 percent population decline due to migration and the death toll from the storm.⁷ These conditions and the uncertainty as to the future population and economy of Puerto Rico are key considerations in this IRP.

⁵ <https://www.wsj.com/articles/batteries-are-taking-over-the-world-1511880319>

⁶ Gross national product

⁷ Per a study from the Harvard T.H. Chan School of Public Health, published in New England Journal of Medicine, May 2018

Outlooks for economic growth vary between highly credible sources including the Financial Oversight and Management Board (FOMB), the World Bank, and the International Monetary Fund. Some suggest a relatively fast recovery from the impacts of the hurricanes due to disaster relief spending, structural reforms and improved fiscal transparency in the Government of Puerto Rico (Government). On the other hand, the Fiscal Plan has the potential to negate some of these economic growth drivers. Central to population and economic growth is a reliable and cost effective electric supply to Puerto Rico.

A more detailed discussion of these impacts, specific to the baseline load projections and range of load uncertainty considered in the IRP analysis, is included in Part 3 – Load Forecast of this report. A real additional risk of future natural disasters in the coming years cannot be ignored. Although these quantum events are difficult to directly include in such an analysis, the range of future market conditions, particularly load growth, aim to incorporate a realistic range of recovery outlooks for Puerto Rico and the resulting impacts to resource decisions over the 20-year planning period are covered in this IRP.

Puerto Rico's exposure to hurricanes and the disruption that they bring to overhead transmission and distribution facilities necessitates that the IRP identifies an optimal balance between local generation resources and limited centralized new generation. To achieve this, the IRP defines portfolios based on the three strategies detailed in Section 5.2. Central to these strategies is the concept of segregating the system into a number of electrical islands (called MiniGrids), defined considering the vulnerabilities of the overhead transmission system, whose lines could take a month or more to rebuild after a major hurricane, and contain the identification of facilities that need to be hardened (e.g., undergrounding) to ensure integrity of supply to critical loads and timely recovery of the balance of the local loads. Appendix 1 provides more details.

The IRP analysis will consider a range of load outcomes as Scenarios (High, Base and Low). Additional variables including the cost of fuel and capital costs for new supply options are also analyzed through sensitivities. Scenario and sensitivity analysis will consider alternate regulatory outcomes (i.e. strengthened future renewable mandate) and future fuel supply options (i.e. natural gas availability to fossil generating facilities located at the north of the island).

2.5 PROMESA Federal Act

The Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA), signed into law by President Obama on June 30, 2016, is a unique federal legislative enactment that includes a number of different provisions that apply to Puerto Rico in respect to its own financial situation. This Law became effective one day before Puerto Rico defaulted on significant payment obligations. Key provisions of PROMESA include:

Financial Oversight and Management Board – PROMESA required a Financial Oversight and Management Board (FOMB) to independently oversee fiscal planning, budgeting, and operations. This Oversight Board consists of seven members appointed by the President of the United States and an ex officio member without voting rights, the Governor or appointee. Among other public entities, PREPA is a listed entity covered by PROMESA and the Oversight Board. As such, activities of PREPA fall under the FOMB, specifically as it relates to its financial planning.

Fiscal Plan – PROMESA requires the development and maintenance of a fiscal plan for Puerto Rico. This plan, at a minimum is required to document the reduction of deficits, payment of debts, and fiscal accountability. Key also to this plan is a description of how critical services, including electric service, will be maintained. Additional contents of PREPA's own fiscal plan are detailed in Part 3 – Load Forecast.

Stay – Title IV of PROMESA implemented a temporary stay on actions and litigation to collect from Puerto Rico entities or enforce liabilities and claims. This stay, similar to protections under the U.S. Bankruptcy code, is enacted to allow Puerto Rico to assess finances and negotiate with creditors.

Debt Reorganization – Title III of PROMESA allows for Puerto Rico or designated representative selected by the FOMB on behalf of the Government to file for reorganizing its debt. This provision maintains elements of Chapter 9 under the U.S. Bankruptcy Code as well as unique provisions specific to Puerto Rico. This includes safe harbors for municipal debts. Title III filing must be approved by the Oversight Board.

2.5.1 Title III

During the Stay period that, with extensions, was in place through May 1, 2017, voluntary negotiations with creditors were ongoing. Following this time, the Oversight Board determined it necessary to file a petition under Title III of PROMESA. The preference is to continue to pursue voluntary negotiations, however the Title III filing was deemed necessary to protect the Government and its people.

As of May 3, 2017, Puerto Rico filed for bankruptcy under Title III of PROMESA. PREPA filed for bankruptcy on July 2017 and became a debtor under Title III of PROMESA. The Government and agencies are working to address the \$70 billion debt. PREPA is working with the Government and its statutory fiscal agent, the Fiscal Agency and Financial Advisory Authority (AAFAF), to reach restructuring and the electric sector transformation.

2.5.2 Title V

Title V defines a Critical Project Process which promotes expedited permitting to advance major projects as those that could be identified in the IRP to develop local generation and/or hardened transmission or distribution facilities to provide resiliency.

Title V establishes the position of the “Revitalization Coordinator,” who operates under the FOMB and who is charged with evaluating infrastructure projects that will provide direct and substantive benefits to Puerto Rico. After receiving a project proposal, the Revitalization Coordinator identifies all Puerto Rico agencies that have a role in permitting, approving, or authorizing the proposed project, and those agencies are required to submit to the Revitalization Coordinator an expedited permitting process, with the goal of ensuring that critical projects are given priority to the maximum extent possible. In the case of energy projects, the process requires the approval of the PREB. The effectiveness of this procedure is still to be confirmed, but it defines a path that would benefit the implementation of the recommendations of this IRP.

2.6 Fiscal Plan

As noted above, PROMESA required the development of a fiscal plan and budget for Puerto Rico that will supersede previous fiscal plans. PREPA submitted its draft fiscal plan on

February 21, 2017 and the latest plan was published, following updates after the post-hurricane restoration in August 2018. PREPA's fiscal plan aligns with the Government's fiscal plan and addresses areas specific to PREPA. The plan focuses on the need for privatization of assets, efficiency in expenditures, and the need for being an economic growth engine for Puerto Rico.

PREPA's current situation including aging and poorly maintained infrastructure, limited fuel options, and operational challenges drive the current high cost of energy service. The ongoing recession has resulted in lower energy sales, and required subsidized service to certain customers. Growing debt limited PREPA's ability to invest in the grid and the PREPA pension fund. As a result, PREPA's service reliability and infrastructure lags industry standards. The fiscal plan details a path to modernization through transformation. Key to this transformation is the development of PREPA's 2018 IRP. Details and timeline for the IRP are included in the plan.

The fiscal plan presents a path forward covering the term through FY2023⁸ based on what is known at this time. Key provisions detailed in the fiscal plan include:

- Behind the meter, distributed generation
- System efficiency, reducing system losses
- Reduce PREPA operating costs (i.e. labor costs and maintenance expenses which were provided by PREPA and reflected in the analysis)
- Updated load outlook to account for post hurricane conditions
- Rates anticipated and rate structure including the ongoing cost of debt service obligation
- Privatization of generating assets

In the fiscal plan, PREPA reports improvements in its liquidity and expectation that it will return to cash flow neutrality in FY2019. Scenarios for post-transformation capital spending and costs are presented. These will be refined and further updated with results of the IRP.

The IRP will be performed within the context of the relevant aspects of the FOMB certified Fiscal Plan for PREPA and the PREPA Governing Board's vision which is presented below.

2.7 PREPA Board Vision Statement

Noting the need for an efficient and resilient system, on February 1, 2018, the PREPA Governing Board released its vision statement to guide the future of the utility. This vision addressed the reliability and resilience of the system, the transition to a sustainable system – both financially and environmentally sustainable – and its importance in acting as an economic growth engine for Puerto Rico. These elements are noted and factored into the structuring of the IRP analysis, Scenarios and sensitivities, and inputs. The vision statement as approved is presented in Exhibit 2-2 below.

⁸ FY means Fiscal Year and, hence, FY2023 is the fiscal year starting July 1, 2022 and ending June 30, 2023

**Exhibit 2-2. PREPA Vision for the Future of Power in
Puerto Rico**

Pillar	Summary
System is Customer-Centric	The system serves the customer with affordable, reliable power, with transparent metrics for quality of service and with equitable consideration across all customers. Quality/Reliability can be differentiated for customers in a manner that serves their total cost and risk objectives. Customers are engaged by innovative products and value-added services that provide choice among rate plan and risk management options and provide access to wholesale contracting options for large customers. Customers are empowered with behind-the-meter alternatives for energy efficiency, demand management, and distributed generation, with the ability to become prosumers if they so choose.
System Promotes Financial Viability	The system is premised on positive economics on both sides of the meter. Rates are reasonable and create value for the customer, while pricing is sufficient to cover costs. Rate and market design create incentives to purchase, consume or produce energy in a manner that benefits the entire system. Subsidies are minimized, and those that remain have a non-distortionary impact. Operational excellence and sound long term planning reduce the cost to serve. Rates are affordable within a model that allows the utility to earn a reasonable rate of return and service its debt. The business model is robust to changes such as outmigration and reduction in energy demand and does not create disincentives for adoption of cheaper energy resources, either at the grid level or at the customer premises.
System is Reliable and Resilient	The grid is thoughtfully planned, well maintained and safely operated to achieve defined reliability and resiliency goals. There is visibility into the system at all levels, and control where appropriate. Standards for recoverability create a measure for resilience. The choice of architecture (distributed vs. regionalized vs. centralized) is intentionally made to balance reliability/resilience and cost objectives while also taking advantage of advancements in technology and innovation.
System is a Model of Sustainability	There is a progressive focus on diversifying energy resources and reducing the carbon intensity of the power sector, in both primary generation and backup generation. Power generation is efficient and minimizes emissions. Customers have incentives to use energy wisely and to generate their own clean energy. The grid and grid systems are designed to take maximum advantage of increasingly cost effective renewable power generation alternatives and to integrate emerging technologies.
System serves as an Economic Growth Engine for Puerto Rico	The quality, reliability, and cost of power attracts new commercial and industrial development to Puerto Rico and encourages existing commercial and industrial customers to expand their operations. Transformation and reinvestment in the power system creates new jobs. Innovation in the generation and delivery of power creates a local ecosystem of businesses that provide for evolving needs for equipment, technology and services in Puerto Rico and beyond.

Source: PREPA, 2018

2.8 Privatization

The Governor of Puerto Rico has publicly stated that the reconstruction and transformation of the electricity sector will include the privatization of PREPA's generating facilities. This would include the generating assets and be complemented by the operation of the transmission and distribution system by a third party. The Law to Transform the Electric System of Puerto Rico was passed on June 12, 2018, becoming Act 120-2018. As a means to transform Puerto Rico's electric system into a modern and sustainable one, system ownership including generating assets will be open to private entities. PREPA and Puerto Rico's Authority for Public-Private Partnerships are to collaborate in the process to privatize assets. Final agreements would need to be ratified by Puerto Rico's Legislature and the Governor.

Request for Proposals are to be issued for PREPA's owned generating units. Bids will be evaluated on metrics that balance commercial interests and social responsibility as well as the bidder's interest and ability to transition to cleaner generating sources when reasonably possible. The act also requires the PREB to sign off on the sales and regulate tariffs and other charges for electricity following the transactions. Under the act, the PREB has fifteen days to review and decide on the approval. Approved contracts would be issued an "energy compliance certificate". Finally, the act expands the PREB's staff to facilitate timely decisions.

Based on the Act 120-2018 authorizing PREPA to sell its generating assets to more than one private buyers, Siemens considered future builds to be financed by third parties, assuming PREPA obtains financial backing to contract as a credit-worthy counterparty if needed.

Load Forecast

This Part covers Siemens load forecast methodology and results. The energy efficiency and demand response complementary to this analysis are presented in Appendix 4.

3.1 Data, Assumptions and Methodology

3.1.1 Historical Energy Sales

PREPA provided monthly historical energy sales for July 1999 – June 2018 (Fiscal Years 2000 – 2008) divided into six customer classes: residential, commercial, industrial, agriculture, public lighting, and other. The commercial sector accounted for 47% of the total sales in FY 2017, followed by residential at 38% and industrial at 13%. Overall, sales to residential, commercial, and industrial customers represented 98% of total sales in FY 2017, the remaining 2% originated from the public lightning sector. These FY 2017 results are generally consistent with the results of recent historical years for sales by customer class.

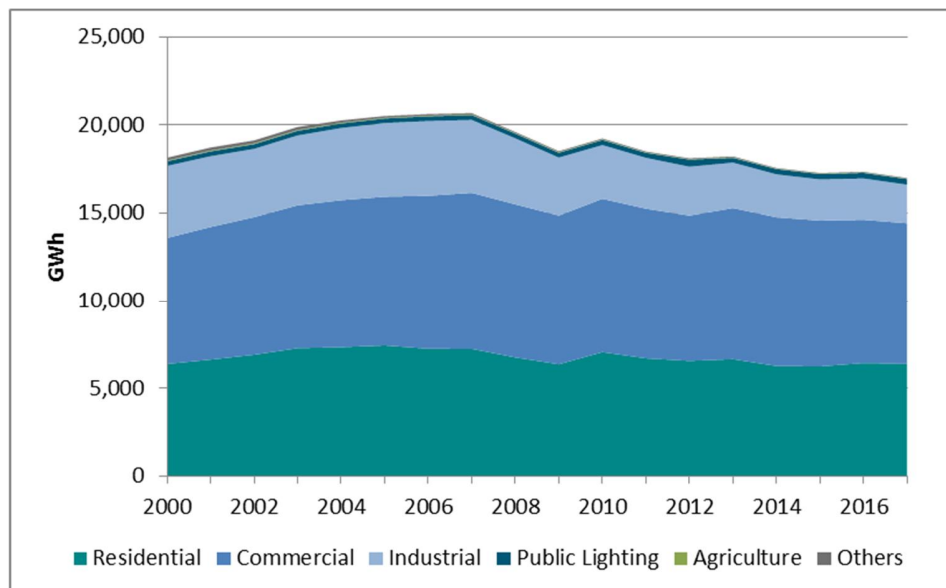
Electricity sales in Puerto Rico declined by 18% since the 2008 recession and net migration. Starting in 2007 until 2017, Puerto Rico's real gross national product (GNP) shrank by approximately 17% and the population declined by over 15%⁹. For FY 2018, total energy sales declined 22%, reflecting the disruption in the transmission and distribution networks due to the hurricanes as well as customer billing delays¹⁰.

Industrial sales declined by 47% in FY 2007 to FY2017, while residential and commercial sales fell 12% and 10% respectively. Industrial share of the total energy sales declined from 20% in FY 2007 to 13% in FY 2017. In contrast, the share of commercial sales increased by 4 percentage points. Exhibit 3-1 shows historical energy sales for FY 2000 to FY2017 by customer class.

⁹ Based on data provided by the Financial Oversight & Management Board (FOMB)

¹⁰ Based on preliminary data provided by PREPA

Exhibit 3-1. Historical PREPA Annual Sales by Customer Class (GWh)



Source: PREPA

PREPA and Financial Oversight & Management Board (FOMB) provided historical data such as population, gross national product (GNP), and weather. These data along with long-term projections of GNP and population were leveraged to create a model and develop gross load forecasts by customer class.

3.1.2 Load Forecast Methodology

The load forecasting methodology employed customer-class specific, statistical and econometric time-series models to develop forecasted monthly energy sales for the three largest customer classes: residential, commercial and industrial. The gross energy consumption forecast was developed using a Classical Linear Regression Model (CLRM) in which the dependent variable, energy sales, is expressed as a linear equation combining the independent variables. For Puerto Rico, 15 variables were used including:

- a weather variable (cooling degree days or CDD)
- two economic variables (population and GNP)
- 12 month specific dummy variables (one for each month of the year) to capture the seasonality of energy demand on a monthly basis

Population was found not to have a statistical significance for industrial. Therefore, manufacturing employment was substituted for population as an independent variable in the regression analysis used to forecast industrial energy consumption.

The econometric model uses an ordinary least-squares regression technique and is developed in MATLAB¹¹. This basic approach is widely used to develop long-term load

¹¹ MATLAB is a numerical computing environment and proprietary programming language developed by MathWorks

forecasts for independent system operators like PJM, the California Energy Commission and individual utilities. Siemens used monthly historical data for FY 2000 through FY 2017 to estimate the regression coefficients applied to the forecast, with 210 observations for each variable.

The unique coefficients that are produced for each independent variable are used to develop the gross energy sale forecast. The 12 monthly dummy binary variables were included in the forecast formulation to capture monthly seasonality in demand. The sum product of the coefficients and variables on a monthly basis result in the gross energy forecast equation is shown below:

$$Demand = C_1 * V_1 + C_2 * V_2 \dots \dots C_{17} * V_{17} + b$$

In the equation above, C_x is the coefficient corresponding to each independent variable V_x , and b represents a constant.

The statistical significance and predicted fit of the model for residential, commercial, and industrial classes was robust, with all three customer classes combined representing approximately 98% of the total load, in line with historical values. Exhibit 3-2 illustrates the variables used to develop the forecast for each of three largest classes.

Exhibit 3-2. Independent variables for Each Customer Classes

Residential	Commercial	Industrial
<ul style="list-style-type: none"> ▪ CDD ▪ GNP ▪ Population ▪ 12 months variable 	<ul style="list-style-type: none"> ▪ CDD ▪ GNP ▪ 12 months variable 	<ul style="list-style-type: none"> ▪ CDD ▪ GNP ▪ Manufacturing employment ▪ 12 months variable

For the smaller customer classes (agriculture, lighting, and other) the overall fit of the CLRM model was weak with the economic and weather fundamental variables providing little explanatory value on the energy consumption for each class. For these customer classes, Siemens developed the forecast of energy consumption for these three classes based on historical seasonality and using a simple extrapolation technique with the expectation that each class will follow similar growth rate as the overall system. This simpler forecast method was deemed acceptable since the three classes collectively represented approximately 2% of the total energy consumption.

3.1.3 Fundamental Drivers for the Load Forecast

In line with the econometric model, Siemens used population, GNP, CDD and the monthly dummy variables as explanatory variables to develop the load forecast by customer class for FY 2019–2038. Other economic data considered included disposable income, income per-capita, and the heat index for weather. However, these additional independent variables were ultimately not incorporated in the final forecast due to their high correlation to other variables already incorporated in the analysis such as CDD (highly correlated to the heat index) or the GNP (highly correlated to disposable income), which diluted their predictive value.

For weather data, Siemens found CDD as the most significant statistically variable to predict the impact of weather on load, which is consistent with Puerto Rico having a tropical climatic zone with year-round warm temperatures averaging 80°F (27°C) in low elevation areas, and 70°F (21°C) in the central mountains of the island. Although temperature variation is relatively modest throughout the year, the overall heat level drives cooling load trends (demand for air conditioning). Weather data was sourced from the National Oceanic and Atmospheric Association (NOAA) for the San Juan station, as a representative for the overall island temperature and rainfall trends. Higher elevation locations were not found to have a significant impact on overall load changes.

Customer rates were considered in the analysis, in particular industrial rates, but they were found not to have a strong historic correlation to demand and explanatory power. From 2000 to 2017, there were periods where industrial demand fell along with declining industrial rates or the opposite. The expectation would be an inverse relationship with lower demand as a consequence of rising industrial rates. The manufacturing sector in Puerto Rico, mostly comprised of pharmaceutical, textiles, petrochemicals, and electronics; appears to be less responsive to changes in customer rates compared to other manufacturing industries such as steel or aluminum, which are highly sensitive (high elasticity). The residential sector is traditionally a sector with low response to changes in retail rates and to some extent the commercial customers. However, sustained high retail rates could change customer behavior and create more incentives for implementation of energy efficiency programs.

Siemens compiled and reviewed macroeconomic data (historical and forecasts) from several sources including Moody's Analytics, the International Monetary Fund, World Bank, the U.S. Census Bureau, Federal Reserve of Economic Data of St. Louis (FRED) and Puerto Rico's Federal Management Oversight Board (FOMB), among others.

Exhibit 3-3 below shows the historical annual values for the independent variables used in the regression analysis.

Exhibit 3-3. Historical Population, Macroeconomic, and Weather Variables

Year	Population (thousands)	GNP (Real Million US dollars)	Cooling Degree Days (Monthly Average)	Manufacturing Employment (thousands)
2000	3,815	6,773	453	143
2001	3,822	6,873	476	132
2002	3,825	6,850	477	121
2003	3,827	6,991	472	118
2004	3,825	7,178	461	118
2005	3,814	7,315	478	115
2006	3,794	7,351	473	110
2007	3,772	7,262	489	106
2008	3,750	7,054	467	101
2009	3,733	6,784	499	92
2010	3,702	6,542	491	87
2011	3,656	6,432	462	84
2012	3,615	6,466	506	82
2013	3,566	6,458	496	76
2014	3,504	6,348	519	75
2015	3,441	6,312	513	74
2016	3,372	6,209	506	74
2017	3,190	6,060	504	72

Source: FOMB (GNP), Moody's Analytics (Population), NOAA (weather), Federal Reserve Bank of St. Louis Economic Data - FRED (Manufacturing Employment)

Before the hurricane, Puerto Rico's economy was in structural decline, with GNP and population falling by at least a percentage point a year since 2006, the last year when the GNP saw an increase. Puerto Rico's GNP shrunk 8% in the decade after the Great Recession with GNP reaching \$6 billion dollars in 2017 (real dollars).

Population declined 15% since 2007 with Maria and Irma accounting for 4 percentage points of this decline in population (182 thousand people in 2017) due to the combined impact of migration and the death toll after the storm, estimated at over 4,100 people¹².

3.1.4 Macroeconomic and Weather Projections

Historical monthly NOAA data was utilized (2000-2016) to develop expected monthly CDD under normal weather conditions. The expected normal weather conditions and its associated monthly CDD was used as a common basis for each year of the energy sales forecast. Exhibit 3-4 shows the normalized CDD used for the forecast.

¹² Per a study from the Harvard T.H. Chan School of Public Health, published in New England Journal of Medicine, May 2018

Exhibit 3-4. Weather Variables

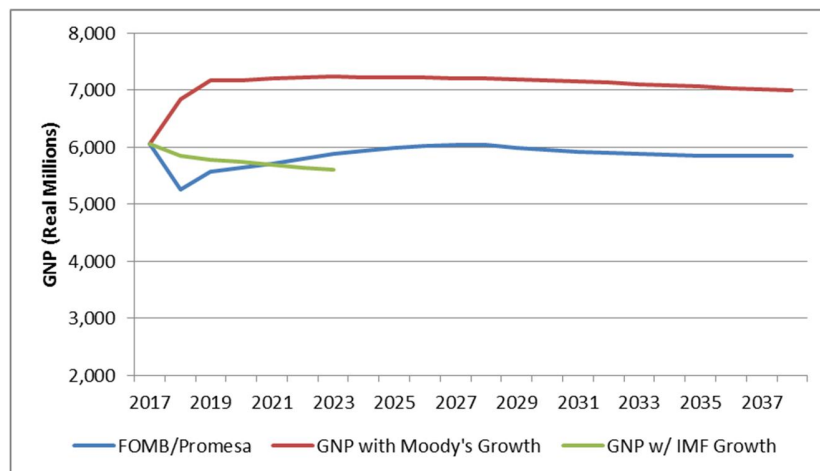
Month	Cooling Degree Days (CDD)
January	391
February	361
March	427
April	454
May	511
June	547
July	567
August	572
September	552
October	552
November	466
December	427

Source: NOAA, Siemens

To be consistent with the FOMB, Siemens used their historical and forecasted data for GNP and population in 2019–2038. According to FOMB, the GNP is estimated to decline 13% for FY 2018, reflecting the impact of hurricanes Maria and Irma on the economy. However, GNP is projected to grow at 6.1% in FY 2019. FOMB forecast shows a relatively fast recovery from Maria’s impact, driven by the effect of the Disaster Relief Fund spending program. In the medium-term GNP is projected to increase at 1.6% per-year in 2019-2027. After 2027, GNP growth is projected to soften to -0.3% per-year. The structural reforms are projected to enhanced economic growth, including a reform of the electrical grid, enhanced fiscal transparency and a labor reform aimed to bring Puerto Rican labor law into closer alignment with U.S. law. An offset to economic growth is expected to come from the proposed fiscal consolidation plan which could bring significant austerity over the next few years to reduce Puerto Rico’s public debt.

Siemens considered other outlooks as well, including Moody’s Analytics (Moody’s) and the International Monetary Fund (IMF), as shown on Exhibit 3-5. Moody’s projects the GNP to recoup much of its hurricane-related losses and to remain relatively stable throughout the forecast horizon. The IMF shows a more pessimistic forecast through 2023 with GNP not recovering from the aftermath of hurricane Maria through 2023.

Exhibit 3-5. Puerto Rico GNP Forecasts

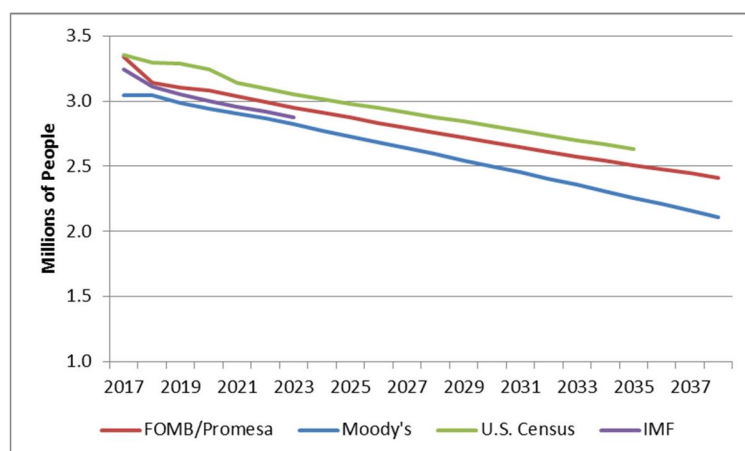


Note: The forecast have been standardized for comparison purposes using the implied growth rates. Moody's GNP forecast is based on real 2009\$ and the IMF based on real 1954\$.

Sources: Moody's June 2018 Forecast, IMF April 2018 WEO, Financial Oversight and Managing Board of Puerto Rico, Fiscal Plan April 2018

The FOMB forecast for population shows a decline of 5.8% in FY2018 due to hurricane fatalities and net migration off the island. Over the study period, FOMB projects population to decline at 1.3% per year in 2019–2038. Population in Puerto Rico is projected to fall by over 900 thousand people by 2038. Moody's projects a faster pace of population loss over the next decade, compared to FOMB, as the island gets increasingly dragged into a negative feedback loop whereby out-migration undermines the tax base and the provision of public services (which deteriorated since Hurricane Maria), will engender more out-migration. The U.S. Census (prior to Maria) projects higher population levels but still with a falling trend through the forecast. The IMF provides a forecast between the projections from FOMB and Moody's.

Exhibit 3-6. Puerto Rico Population Forecast



Sources: Moody's June 2018 Forecast, IMF April 2018 WEO, US Census Bureau August 2017

Exhibit 3-7 shows the long-term economic forecast used in the load forecast.

Exhibit 3-7. Macroeconomic Long Term Forecast

Fiscal Year	Population (thousands of people)	GNP (Real Millions US dollars)	Manufacturing Employment (thousands of people)
2018	3,143	5,251	70
2019	3,104	5,573	69
2020	3,084	5,632	70
2021	3,039	5,707	70
2022	2,995	5,792	70
2023	2,951	5,873	70
2024	2,910	5,941	71
2025	2,871	5,991	71
2026	2,833	6,029	71
2027	2,794	6,041	72
2028	2,756	6,038	72
2029	2,718	5,984	73
2030	2,681	5,949	73
2031	2,644	5,922	74
2032	2,609	5,897	74
2033	2,575	5,877	75
2034	2,541	5,862	75
2035	2,508	5,852	76
2036	2,476	5,847	77
2037	2,445	5,846	77
2038	2,414	5,849	78

Source: FOMB (population and GNP), Siemens for Manufacturing employment

3.1.5 Long Term Energy Forecast

Exhibit 3-8 shows Siemens forecasted gross energy sales by customer class. The forecast does not include any future energy efficiency and/or demand response programs and distributed generation (DG) in addition to current programs in place. The impact of those programs is addressed and modeled separately as discussed in later sections of this document. The forecast includes the impact of naturally occurring energy efficiency savings, such as more efficient household appliances, in as much these efficiency savings are embedded in the historical energy consumption data used to create the forecast.

Exhibit 3-8. Gross Sales Demand by Customer Class

Fiscal Year	Residential Sales (GWh)	Commercial Sales (GWh)	Industrial Sales (GWh)	Agricultural Sales (GWh)	Public Lighting Sales (GWh)	Other Sales (GWh)	Total Sales (GWh)
2019	5,472	7,962	1,491	26	315	35.6	15,301
2020	5,480	7,948	1,551	26	316	35.8	15,357
2021	5,473	7,917	1,635	26	317	35.9	15,403
2022	5,473	7,886	1,730	26	318	36.0	15,470
2023	5,470	7,856	1,822	27	320	36.2	15,530
2024	5,464	7,827	1,900	27	320	36.3	15,574
2025	5,451	7,801	1,960	27	321	36.3	15,595
2026	5,431	7,774	2,008	27	321	36.3	15,596
2027	5,396	7,747	2,028	27	320	36.2	15,554
2028	5,353	7,721	2,032	26	319	36.1	15,487
2029	5,284	7,695	1,984	26	316	35.7	15,341
2030	5,223	7,669	1,956	26	313	35.5	15,223
2031	5,168	7,644	1,937	26	311	35.2	15,120
2032	5,115	7,619	1,921	26	309	35.0	15,025
2033	5,065	7,596	1,910	26	307	34.8	14,939
2034	5,020	7,572	1,905	25	306	34.6	14,862
2035	4,978	7,549	1,905	25	304	34.5	14,796
2036	4,940	7,527	1,911	25	303	34.3	14,741
2037	4,905	7,506	1,921	25	302	34.2	14,694
2038	4,873	7,484	1,935	25	302	34.1	14,654
CAGR	-0.61%	-0.32%	1.38%	-0.23%	-0.23%	-0.23%	-0.23%

Note: The sales forecasts reflect gross energy sales inclusive of existing EE programs. It does not include losses, PREPA's own use and auxiliary demand neither any future incremental EE and/or demand response programs.

Gross energy sales are projected to increase by 15% in fiscal year 2019 due to the projected, near-term recovery in the economy. However, over the full 20-year study period, gross energy sales are projected to decline at average of 0.23% per-year driven by the long-term decline in population and softening of the GNP growth after 2027. Among customer classes, the industrial class is the only customer class projected to have a positive average growth over the study period, at an average of 1.4% per-year, primarily driven by the projected economic growth through 2026. In contrast, the residential and commercial classes are projected to decline by an average of 0.6% and 0.3% per-year, mostly driven by the long-term decline in population.

Agriculture, public lighting and "other" are projected to decline in line with the overall system average of -0.23% per year. The public lighting forecast does not include the impact of a wide spread replacement of the current metal-vapor-based public lighting with LED light bulbs. LED replacement and other energy efficiency programs are addressed in a separate document; however, at the end of this report, Siemens provides a summary of the effects of energy efficiency programs on the load forecast.

Exhibit 3-9 illustrates the gross energy demand inclusive of the generation auxiliary loads, technical and non-technical losses, and PREPA's own use. The first column, gross energy sales, reflects the totals from the exhibit above. PREPA's own use is assumed to stay constant through the forecast. The forecast includes no material change in the auxiliary generation load, and for modeling purposes is assumed to be constant until the plants retire.

However, in the portfolio Scenario analysis of the Integrated Resource Plan, future retirements are incorporated into the forecast and their corresponding impact on demand.

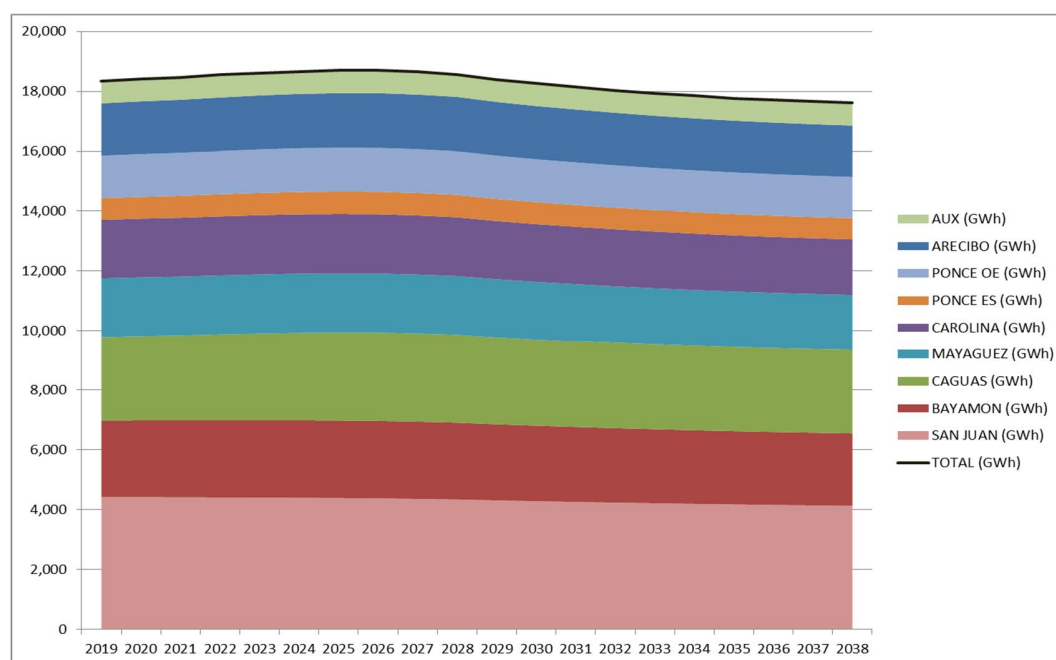
Exhibit 3-9. Gross Energy Demand for Generation

Fiscal Year	Gross Energy Sales (GWh)	Technical Losses (GWh)	Non-Technical Losses (GWh)	Auxiliary (GWh)	PREPA Own Use (GWh)	Total Energy Demand (GWh)
2019	15,301	1,438	827	751	34	18,351
2020	15,357	1,444	830	751	34	18,415
2021	15,403	1,448	832	751	34	18,469
2022	15,470	1,454	836	751	34	18,545
2023	15,530	1,460	839	751	34	18,613
2024	15,574	1,464	841	751	34	18,665
2025	15,595	1,466	842	751	34	18,689
2026	15,596	1,466	843	751	34	18,690
2027	15,554	1,462	840	751	34	18,642
2028	15,487	1,456	837	751	34	18,565
2029	15,341	1,442	829	751	34	18,397
2030	15,223	1,431	822	751	34	18,261
2031	15,120	1,421	817	751	34	18,144
2032	15,025	1,412	812	751	34	18,034
2033	14,939	1,404	807	751	34	17,935
2034	14,862	1,397	803	751	34	17,848
2035	14,796	1,391	799	751	34	17,772
2036	14,741	1,386	796	751	34	17,708
2037	14,694	1,381	794	751	34	17,654
2038	14,654	1,377	792	751	34	17,608
CAGR	-0.23%	-0.23%	-0.23%	0.00%	0.00%	-0.22%

To assess the geographical location of the demand above, as necessary for the modeling of the system, PREPA provided the composition of the load in term of customer classes (residential, commercial, industrial, etc.) by County which was used to map the forecast to each of the areas into which the system is modeled. Exhibit 3-10 and Exhibit 3-11 shows the resulting allocation of the Energy Demand for Generation above in tabular and graphic form.

Exhibit 3-10. Gross Energy Demand for Generation by Area

Fiscal Year	ARECIBO (GWh)	BAYAMON (GWh)	CAGUA S (GWh)	CAROLIN A (GWh)	MAYAGÜEZ (GWh)	PONCE ES (GWh)	PONCE OE (GWh)	SAN JUAN (GWh)	AUX (GWh)	TOTAL (GWh)
2,019	1,748	2,558	2,818	1,956	1,961	719	1,422	4,417	751	18,351
2,020	1,759	2,566	2,840	1,961	1,966	724	1,429	4,418	751	18,415
2,021	1,771	2,571	2,866	1,965	1,969	729	1,436	4,411	751	18,469
2,022	1,787	2,579	2,898	1,970	1,974	736	1,445	4,406	751	18,545
2,023	1,801	2,585	2,927	1,975	1,978	742	1,453	4,401	751	18,613
2,024	1,813	2,590	2,951	1,978	1,981	746	1,460	4,394	751	18,665
2,025	1,820	2,591	2,968	1,979	1,981	750	1,464	4,385	751	18,689
2,026	1,824	2,589	2,978	1,978	1,979	751	1,466	4,374	751	18,690
2,027	1,821	2,581	2,975	1,971	1,972	750	1,462	4,357	751	18,642
2,028	1,815	2,569	2,965	1,962	1,963	747	1,457	4,337	751	18,565
2,029	1,794	2,544	2,930	1,945	1,945	739	1,442	4,307	751	18,397
2,030	1,779	2,524	2,903	1,930	1,931	732	1,430	4,280	751	18,261
2,031	1,766	2,506	2,882	1,917	1,918	727	1,420	4,256	751	18,144
2,032	1,755	2,490	2,862	1,905	1,905	722	1,411	4,233	751	18,034
2,033	1,744	2,475	2,845	1,894	1,894	717	1,403	4,211	751	17,935
2,034	1,736	2,461	2,831	1,885	1,884	714	1,396	4,191	751	17,848
2,035	1,728	2,449	2,820	1,876	1,875	710	1,390	4,172	751	17,772
2,036	1,723	2,439	2,812	1,868	1,867	708	1,385	4,155	751	17,708
2,037	1,719	2,430	2,806	1,862	1,860	706	1,381	4,139	751	17,654
2,038	1,715	2,422	2,802	1,856	1,854	705	1,378	4,124	751	17,608

Exhibit 3-11. Graph of Gross Energy Demand for Generation by Area

Source: Siemens

The IRP Regulation issued by the PREB requires the load forecast evaluation include:

- Comparisons of prior forecasts versus actual data
- An explanation of the cause of any significant deviation between the prior forecasts and the actual annual peak demand and energy that occurred
- An explanation of the impact that historical demand—side resources had on the prior load forecast.

Siemens believes the comparisons with actual data to recent forecasts have been rendered meaningless by structural changes in the island population, economy and energy consumption that have taken place as a result of Hurricane Maria. A more meaningful comparison is the significant changes resulting from Hurricane Maria to the forecasts. Exhibit 3-12 illustrates the differences in the customer class level energy sales forecasts developed for the 2015 IRP and the forecasts developed for this 2018 IRP. Exhibit 3-13 provides a comparison of the forecasted total energy sales from the 2015 IRP versus this 2018 IRP.

Exhibit 3-12: Comparison of 2015 versus 2018 IRP Forecasted Class-Level Energy Sales

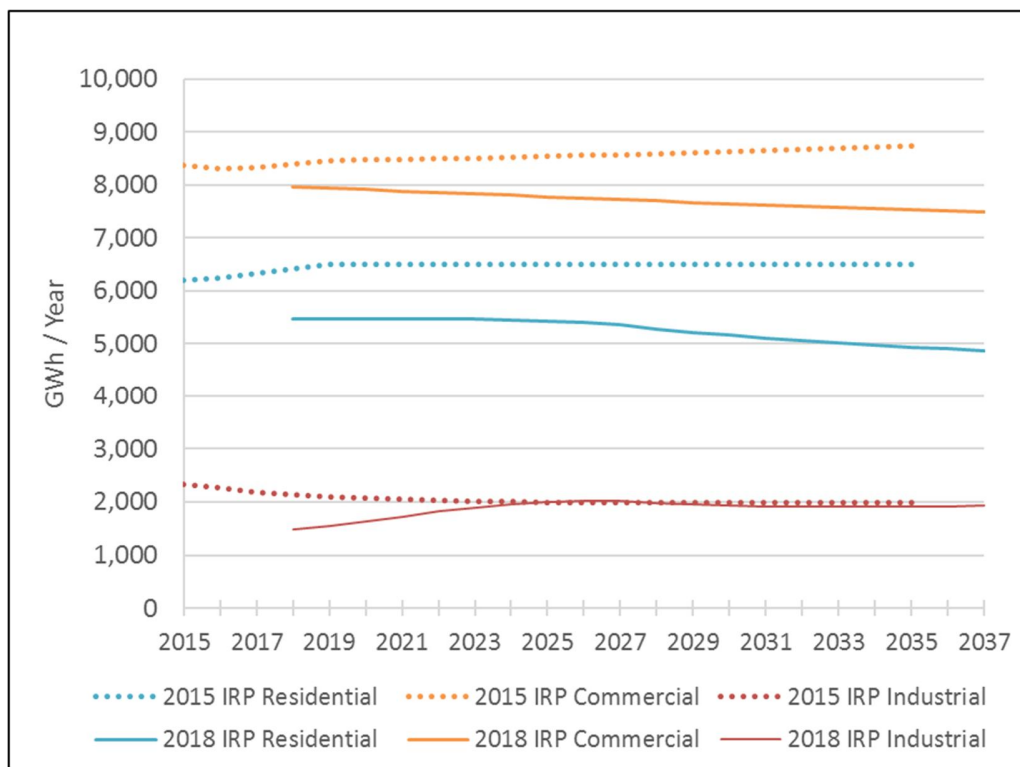
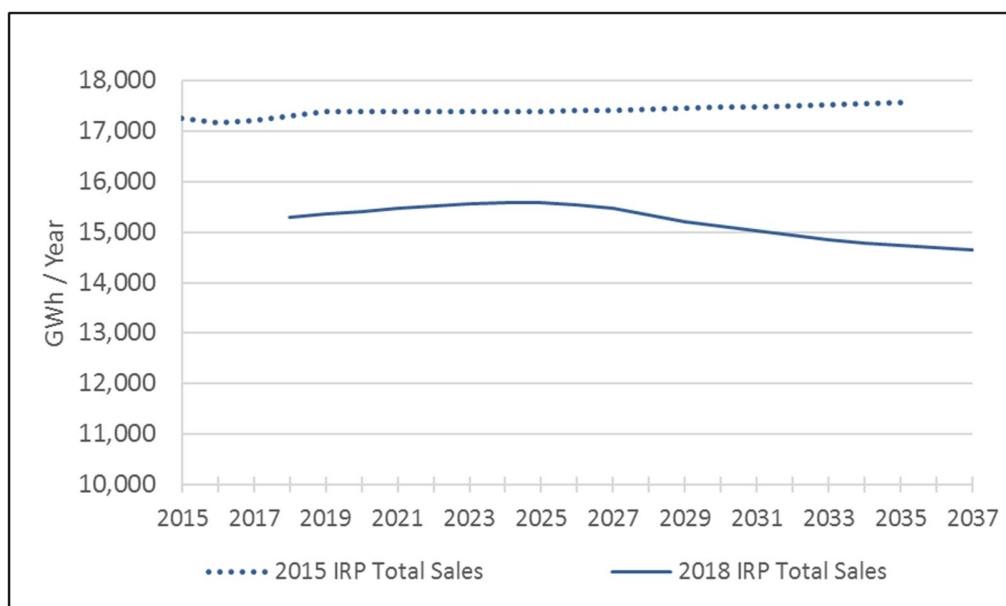


Exhibit 3-13: Comparison of 2015 versus 2018 IRP Forecasted Total Energy Sales

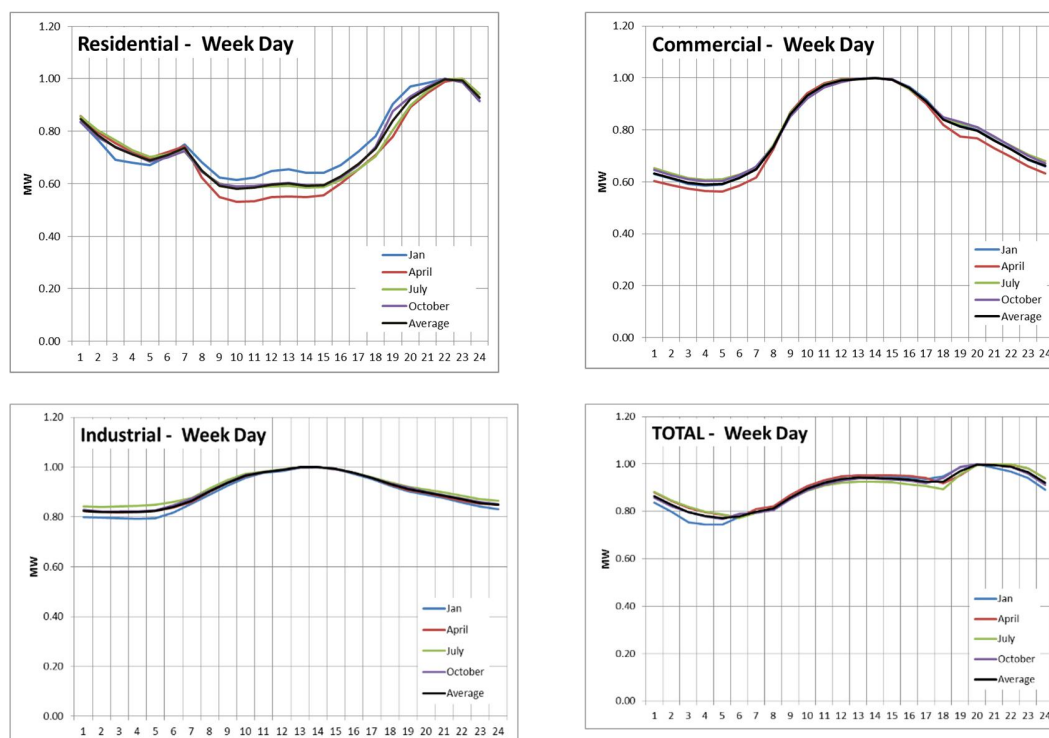


3.1.6 Long Term Peak Demand Forecast

To estimate the peak demand associated with the energy forecast the expected load factors (i.e. the ratio of average demand to the peak demand) for each customer class was assessed along with the percentage of their peak demand that occurs at the time of the system peak (called Customer Class Coincidence Factor – CCCF – or Contribution to the Peak Factor). In principle, these factors would ordinarily be determined monthly, consistent with the monthly detail of the energy forecast and include an analysis of load factors and coincident factors over multiple years. However, for this study, a single annual average load factor value was used for each class due to the fact that: a) there was not a significant change in the hourly load shapes for the relevant customer classes across the year, b) the load factor can be volatile unless averages are used due to its dependence on the measured peak, c) only one-year worth of hourly load data by customer class was available. The inclusion of a stochastic distribution of energy forecasts, discussed in later sections of this report, serves to drive a large range of forecasted peak demand.

Exhibit 3-14 shows the normalized load shapes for the main customer classes (residential, commercial and industrial) that constitute the vast majority of the forecasted energy consumption as well as the system total. As can be observed, unlike the mainland U.S. where there are large changes in the shape from summer to winter, the Puerto Rico load shapes show little seasonal variation (residential shows the greatest variation). An average annual load factor represents a reasonable method to represent each customer class. Exhibit 3-14 also illustrates that there are two peaks a day, the first in the daytime hours driven by commercial and industrial loads and the second an evening peak driven by the residential load. The evening peak is the higher of the two daily peaks. Thus, the residential customers peak coincides with the system peak (CCCF =1) while the industrial and commercial customers have a load below their respective class level peak loads at the time of the system peak load (CCCF < 1).

Exhibit 3-14. Normalized Load Shapes for main Customer Classes and System Total



Based on the hourly information provided by PREPA, Siemens estimated the Customer Class Load Factors and Customer Class Coincidence Factors (% of the Customer Class peak at the time of the System Peak) shown in Exhibit 3-15.

Exhibit 3-15. Selected Load Factors and Customer Class Coincidence Factor

Customer Class	Customer Class Load Factor %	Customer Class Coincidence Factor %
Residential	66.9%	100%
Commercial	70.2%	70%
Industrial	81.2%	85%
Lighting	49.3%	100%
Other	73.6%	80%
Agriculture	46.8%	32%

Using the values above and the forecasted energy consumption by customer class, the demand at the time of system peak can be forecasted. To this forecast peak load the following elements of load were added:

- a) The effect of the technical transmission and distribution technical losses using a correction to convert energy losses into capacity losses based on the load factor¹³.
- b) The non-technical losses using same load factor and CCCF values as the residential load.
- c) PREPA's own consumption using an estimated load factor based on historical values.
- d) The effects of the consumption on the generating plants auxiliary services.

Exhibit 3-16 shows the energy demand and peak demand for generation, inclusive of the factors indicated above (technical and non-technical losses, auxiliary demand and PREPA's own use). Exhibit 3-16 does not include the impact of future energy efficiency (EE), demand response programs or DG. It should be noted that while DG is modeled separately as a source, it does have an impact in reducing the T&D technical losses and this is accounted for in the final forecast together with the impacts of EE, as is discussed later in this report. Demand Response is a resource used to provide reserves and it does not affect the load forecast.

Peak demand (before EE) is projected to decline by 0.24% per year. The lower rate of peak growth relative to the energy demand is a consequence of more modest growth in the residential demand compared to commercial demand and the corresponding contribution of each class to system peak demand. Commercial load peaks during the day, while the residential load peaks in the evening (sometimes very late), the latter driving the system peak. A reduction in residential load results in a reduction in the evening peak and an increase in the overall system load factor.

¹³ Capacity Losses % = (Energy Losses %) / (0.3+0.7*LF)

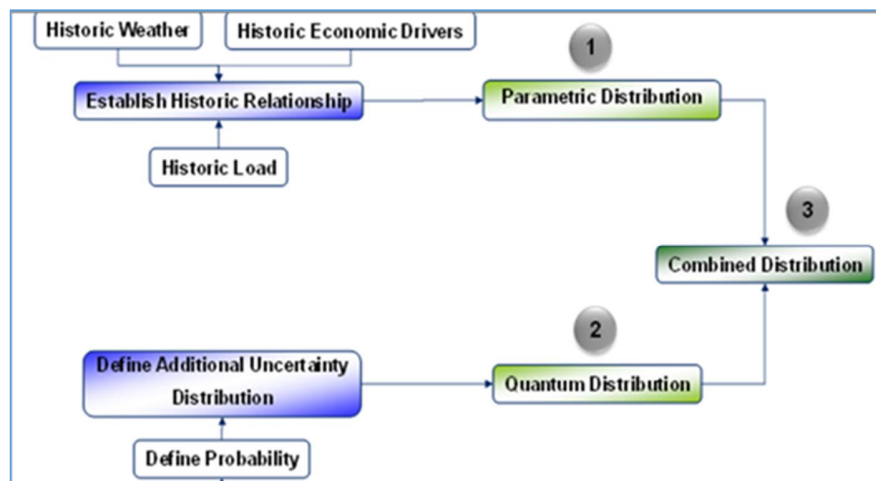
Exhibit 3-16. Gross Generation

Fiscal Year	Energy (GWh)	Peak Demand (MW)	Load Factor (%)
2019	18,353	2,791	75.1%
2020	18,417	2,799	75.1%
2021	18,471	2,805	75.2%
2022	18,547	2,815	75.2%
2023	18,615	2,823	75.3%
2024	18,666	2,829	75.3%
2025	18,691	2,831	75.3%
2026	18,691	2,830	75.4%
2027	18,644	2,822	75.4%
2028	18,567	2,810	75.4%
2029	18,399	2,785	75.4%
2030	18,264	2,765	75.4%
2031	18,146	2,748	75.4%
2032	18,037	2,731	75.4%
2033	17,938	2,716	75.4%
2034	17,851	2,703	75.4%
2035	17,775	2,692	75.4%
2036	17,711	2,682	75.4%
2037	17,657	2,673	75.4%
2038	18,353	2,666	75.4%
CAGR	-0.22%	-0.24%	

Note: Forecast includes technical and non-technical losses, auxiliary demand and PREPA's own use. The forecast does not include the impact of future energy efficiency and/or demand response programs.

3.1.7 Stochastic Distribution

To generate Scenarios for energy growth, Siemens developed statistical distributions based on deterministic energy forecasts. The process involves two steps: the first involves developing parametric distributions around key fundamental variables that could present more volatility in the future (weather and economic performance in Puerto Rico). Siemens utilized historical data to develop 2,000 Scenarios for weather and GNP that were fed into the econometric regression model to determine 2,000 iterations of average and high energy growth. The second step involves developing quantum distributions, which incorporate future uncertainties not captured by the historical data. The overall process is summarized by the flow chart in Exhibit 3-17 below.

Exhibit 3-17. Stochastic Process for Energy Forecasts

3.1.8 Parametric Distributions

The development of stochastics is based on building probability distributions around the deterministic energy forecast. To produce probability distributions of the energy forecast, Siemens propagates three independent random paths: CDD, GNP, and a residual.

- To produce reasonable weather data projections, Siemens sampled 17-years of monthly historical weather data based on CDD for 2000-2017.
- GNP is assumed to follow a Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the GNP could behave at any time in the future. The process is developed using historical quarterly GNP data for 2000-2017.
- Finally, to account for unexplained variation in the observed data, Siemens adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error from a stepwise regression.

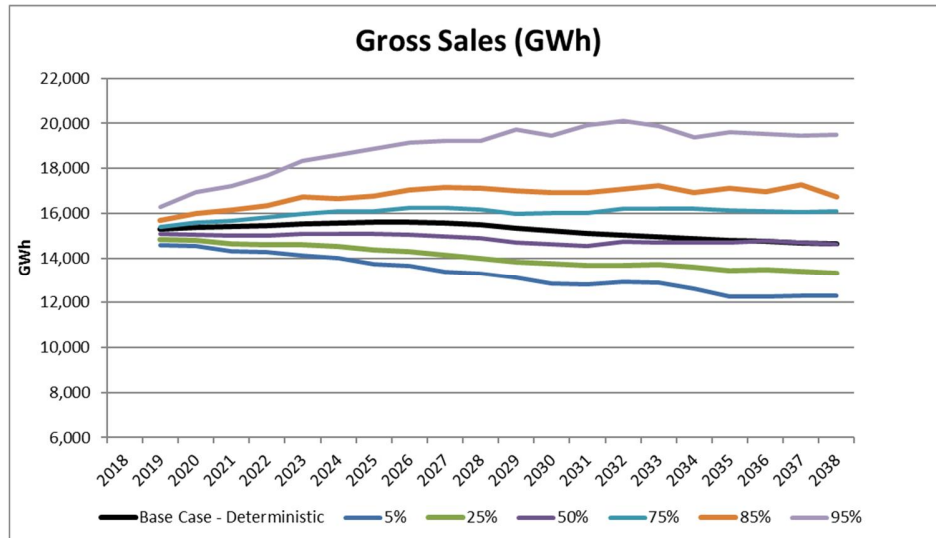
Based on historical volatility, 2,000 distributions of these variables are developed and used in the stepwise regression model to develop an intermediate distribution of average and peak energy forecast distributions.

3.1.9 Quantum Distribution: Additional Variability

It is Siemens' opinion that future energy demand may differ substantially from past energy demand. To account for this possibility, Siemens adds an additional "Quantum Distribution" to its empirically derived distribution. The 5th percentile of this distribution reflects a low growth Scenario (i.e. higher degree of DSM and DG penetration). The upper tail of this distribution (95th Percentile) is weighted to match Siemens' analysis of historical high periods of energy growth and to capture other events such as higher penetration of air conditioning loads and rising demand from electric vehicles. Using these high and low growth Scenarios, Siemens generates a distribution of energy forecasts using statistical techniques. This distribution is superimposed on the parametric distribution obtained in the step discussed above. The resulting distribution is considered the final average and peak energy forecast distribution (2,000 iterations).

Exhibit 3-18 shows an illustrative stochastic distribution of gross sales for planning purposes.

Exhibit 3-18. Stochastic Distribution of Gross Sales



Note: The sales forecasts reflect gross energy sales inclusive of existing EE programs. It does not include losses, PREPA's own use and auxiliary demand neither any future incremental EE and/or demand response programs.

The mean path corresponds to the average of 2,000 iterations of combinations of the stochastic input drivers. The percentile bands are not energy paths but instead represent the likelihood that the sales could be at or below that level in a given year. For example, in 2025 there is a 95% likelihood that energy sales will be at or below 18,885 MWh. Also, in 2025, there is a 5% chance that energy sales will be at or below 14,352 MWh.

Based on its assessment of the results of the stochastic distributions, Siemens chose to use the 25th percentile as the low case and the 85th percentile as the high case for all Scenarios. In general, the 75th and the 25th percentile represent approximately one standard deviation above and below the mean on a normal distribution. However, load tends to follow a log normal distribution, which tends to have an upward bias. As result, Siemens considered that using the 85th percentile would be more reasonable for the high case.

The 85th and 25th percentiles do not represent extreme cases either but a reasonable high and low forecast for planning purposes. The extreme high and low would typically be defined by the 95th percentile and 5th percentile, respectively.

To describe the factors that could give rise to the extreme high and low forecasts mathematically obtained above, Siemens developed a very optimistic Scenario and a very pessimistic Scenario for the macroeconomic parameters driving the forecast: GNP and population.

The very optimistic case assumes that the structural reforms in Puerto Rico are highly successful and the GNP after hitting a low in 2018 bounces back at a rate 50% faster than Moody's forecast for two years as federal funds are invested in the island. From 2020 onwards, the Puerto Rico economy recovers to its pre-2006 potential and the GNP grows at 75% of the US GNP forecast growth rate – see Exhibit 3-19. Consistent with this economic

outlook, there is initially a population drop following the U.S. Census forecast until 2019 and from 2020 onwards, as the Puerto Rico economy starts to grow, the population outflow reduces to only 25% of the yearly attrition in the U.S. Census forecast – see Exhibit 3-20.

The very pessimistic case, assumes that the structural reforms do not take place and there is limited federal funds invested in the island, resulting in a continuation of the GNP decline at 1% per year in line with the historical post 2006 decline. Consistent with this outlook the population decline accelerates and after an initial drop in line with FOMB forecasts, from 2019 onwards it declines at 1.5 times yearly attrition in this forecast.

Exhibit 3-19. GNP Scenarios

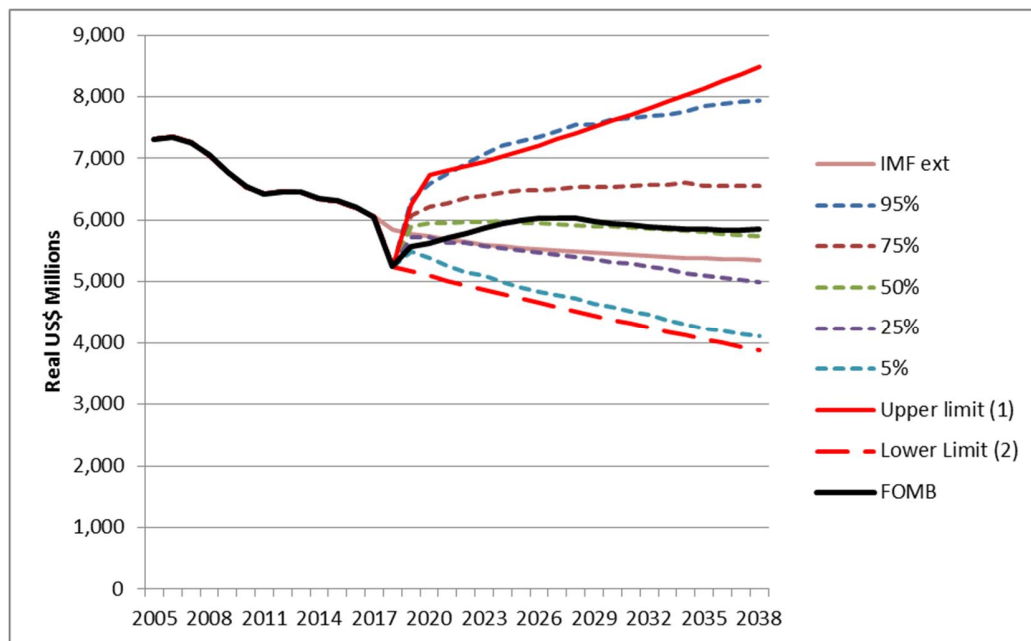
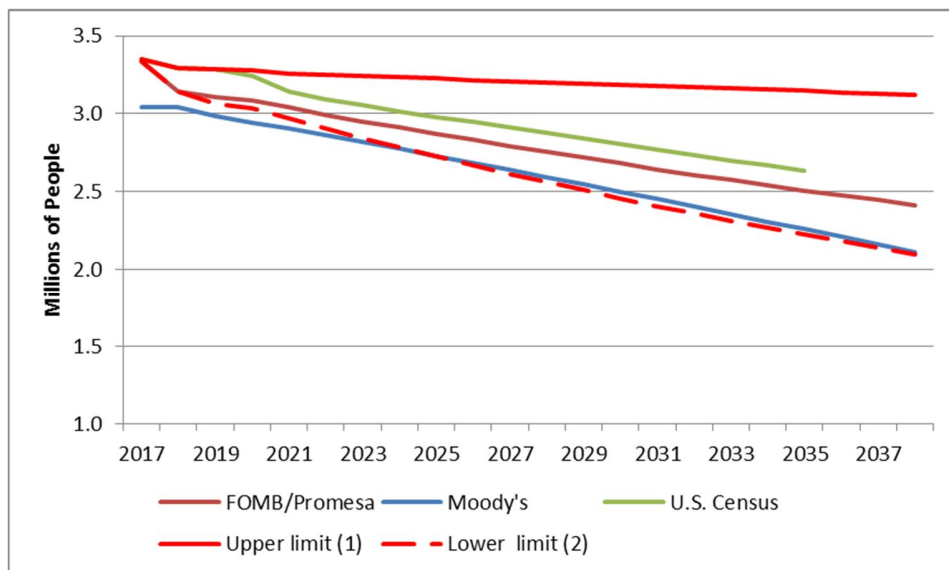


Exhibit 3-20. Population Scenarios

The resulting gross sales forecasts for the Upper and Lower limits are shown in Exhibit 3-21. In the high case Scenario, gross energy sales increase at 1.34% per-year, with sales reaching 20,672 GWh by 2038 – 41% higher than the reference case. In the low case Scenario, gross energy sales decline at 1.50% per-year reaching 11,033 GWh by 2038, 75% below the reference case level. The industrial customer class has the most upside or downside potential driven by changes in the GNP and/or population from all three classes, with sales growing at 5.6% per-year in the high case or declining at 5.2% per-year in the low case. The forecasts below do not include the impact of new energy efficiency programs.

Exhibit 3-21. Gross Sales Forecast Scenarios – High and Low Cases

Fiscal Year	Gross Energy Sales Reference (GWh)	Gross Energy Sales Very Optimistic (GWh)	Gross Energy Sales Very Pessimistic (GWh)	Gross Energy Sales High Case (GWh)	Gross Energy Sales Low Case (GWh)
2019	15,301	16,043	14,703	15,670	14,844
2020	15,357	17,400	14,470	16,001	14,811
2021	15,403	17,869	14,257	16,166	14,636
2022	15,470	17,976	14,015	16,358	14,596
2023	15,530	18,102	13,776	16,730	14,588
2024	15,574	18,239	13,545	16,642	14,514
2025	15,595	18,385	13,325	16,755	14,352
2026	15,596	18,540	13,112	17,024	14,292
2027	15,554	18,699	12,901	17,136	14,148
2028	15,487	18,863	12,695	17,114	13,989
2029	15,341	19,030	12,498	16,998	13,831
2030	15,223	19,200	12,304	16,939	13,740
2031	15,120	19,372	12,118	16,932	13,664
2032	15,025	19,547	11,939	17,078	13,690
2033	14,939	19,725	11,765	17,235	13,702
2034	14,862	19,906	11,597	16,923	13,582
2035	14,796	20,091	11,439	17,113	13,435
2036	14,741	20,280	11,295	16,976	13,476
2037	14,694	20,474	11,160	17,270	13,390
2038	14,654	20,672	11,033	16,719	13,323
CAGR	-0.23%	1.34%	-1.50%	0.34%	-0.57%

Part

4

Existing Resources

4.1 Existing Generation Resources and Distributed Generation

Siemens reviewed cost and technical characteristics and operating status on PREPA's existing generation resources and Power Purchase and Operating Agreements (PPOAs) as inputs to the IRP. The thermal supply-side resources section of this report (Appendix 5 – New and Existing Supply-Side Resources Supplemental Data) includes a review of the operating characteristics of the generation units along with their operating costs.

On the other hand, Part 6 – New Resources Options of this report presents the new resources considered in the IRP and Appendix 4 – Demand Side Resources presents a discussion of the demand side resources including distributed generation, energy efficiency, demand response, and CHP (Combined Heat and Power).

4.1.1 PREPA's Existing Generation Facilities

Siemens reviewed and discussed PREPA's existing generation resources, including the units' condition and operating status, with PREPA's staff. As a result of this review, 39 existing generation units, with a total capacity of 5,010 MW, were determined to be in acceptable operating condition for consideration as available resources in this IRP.

Exhibit 4-1 presents the operational parameters including technology (i.e., steam turbine [ST], simple cycle combustion turbines, referenced as gas turbines per PREPA conventions [GT], and combined cycle gas turbine [CC]), rated capacity¹⁴, fuel type, heat rate, fixed operating and maintenance costs (FOM), and variable operating and maintenance costs (VOM) of the existing generation resources in 2018 dollars.

¹⁴ The maximum capacities considered in the study are based on information provided by PREPA. These capacities are smaller than the nominal capacities in the case of San Juan 5 and 6 CC (nominal capacity of 220 MW each), Aguirre CC 1 and 2 (nominal capacity of 296 MW each), Mayagüez GT (nominal capacity of 55 MW each), and the hydro generation (nominal capacity of 105 MW). The total nominal capacity of existing PREPA generation resources is 5,213 MW.

Exhibit 4-1. PREPA Existing Units Included in the IRP

	Generation Units	Maximum Modeled Capacity (MW)	Fuel	Heat Rate at Max. Capacity (BTU/kWh)	FOM (2018 \$/kW-year)	VOM (2018 \$/MWh)
MATS Affected Units	Aguirre 1 ST	450	No. 6 fuel oil	9,600	32.04	2.25
	Aguirre 2 ST	450	No. 6 fuel oil	9,700	32.04	2.25
	Costa Sur 5 ST	410	Natural gas	9,747	35.96	2.72
	Costa Sur 6 ST	410	Natural gas	9,747	35.96	2.72
	Palo Seco 3 ST	216	No. 6 fuel oil	9,725	46.47	4.95
	Palo Seco 4 ST	216	No. 6 fuel oil	9,725	46.47	4.95
	San Juan 7 ST	100	No. 6 fuel oil	10,497	49.02	2.93
	San Juan 8 ST	100	No. 6 fuel oil	10,445	49.02	2.93
Combined Cycle	Aguirre 1 CC	260	Diesel	11,140	22.64	6.79
	Aguirre 2 CC	260	Diesel	11,140	22.64	6.79
	San Juan 5 CC	200	Diesel	7,625	27.40	2.22
	San Juan 6 CC	200	Diesel	7,853	27.40	2.22
Gas Turbine	Cambalache 2 GT	83	Diesel	11,549	24.44	5.52
	Cambalache 3 GT	83	Diesel	11,549	24.44	5.52
	Mayagüez 1 GT	50	Diesel	9,320	10.64	6.40
	Mayagüez 2 GT	50	Diesel	9,320	10.64	6.40
	Mayagüez 3 GT	50	Diesel	9,320	10.64	6.40
	Mayagüez 4 GT	50	Diesel	9,320	10.64	6.40
	Daguao 2 GTs	42	Diesel	14,400	26.54	20.19
	Palo Seco GT11 & GT12	42	Diesel	14,400	26.54	20.19
	Palo Seco GT21 & GT22	42	Diesel	14,400	26.54	20.19
	Palo Seco GT31 & GT32	42	Diesel	14,400	26.54	20.19
	Aguirre GT21 & GT22	42	Diesel	14,400	26.54	20.19
	Costa Sur GT11 & GT12	42	Diesel	14,400	26.54	20.19
	Jobos GT11 & GT12	42	Diesel	14,400	26.54	20.19
	Yabucoa GT11 & GT12	42	Diesel	14,400	26.54	20.19
	Vega Baja GT11 & GT12	42	Diesel	14,400	26.54	20.19
Hydro	Hydro	34	Water	N/A	N/A	N/A
IPP Units	AES Coal 2 Units	454	Coal	9,791	79.46	7.23
	EcoEléctrica Plant	507	Natural gas	7,497	189.34	0.00
Total		5,010				

Source: PREPA, Siemens.

Note: while San Juan 7 & 8 are included in the model, and 9 & 10 were not, from a modeling perspective they are fully interchangeable. If PREPA determines that San Juan 9 is more reliable than one of the other units, it may be substituted without impacting model results.

It was jointly decided that 11 existing generation units, with a total capacity of 707 MW, were not in sufficient operational condition for inclusion as a generation resource in this IRP. A summary of the excluded units is shown below:

Exhibit 4-2. PREPA Existing Units Excluded from the IRP

	Generation Units	Capacity (MW)
Steam Turbine (MATS Affected)	Costa Sur 3 ST	85
	Costa Sur 4 ST	85
	Palo Seco 1 ST	85
	Palo Seco 2 ST	85
	San Juan 9 ST	100
	San Juan 10 ST	100
Gas Turbine	Cambalache 1 GT	83
Total		623

Source: PREPA, Siemens.

Note: San Juan 9 may be substituted for San Juan 7 or 8 without material impacts to model results.

4.1.1.1 Steam Turbines (ST)

PREPA has a total of 14 ST units with a total capacity of 2,892 MW located at four sites, Palo Seco (4 units, 602 MW) and San Juan (4 units, 400 MW) in the north; Aguirre (2 units, 900 MW) and Costa Sur (4 units, 990 MW) in the south. All the ST units are subject to Mercury and Air Toxics Standards (MATS) compliance requirements. A total of 6 of the 14 ST units, 2 each at Palo Seco, San Juan and Costa Sur, as listed in Exhibit 4-2, were excluded from resources for this IRP due to their age and current non-operational condition.

The remaining eight MATS-affected units, with a total capacity of 2,352 MW, were operational and included in this IRP. These ST units are located at four sites including Palo Seco (2 units, 432 MW), and San Juan (2 units, 200 MW) in the north; and Aguirre (2 units, 900 MW), and Costa Sur (2 units, 820 MW) in the south. The Costa Sur ST units 5&6 are MATS compliant and have dual fuel capability, which can also burn No. 6 fuel oil but currently burn 100 percent natural gas. Exhibit 4-3 shows the unit level parameters of the eight ST units included in the IRP.

Exhibit 4-3. ST Unit Parameters (Aguirre, Costa Sur, Palo Seco, San Juan)

Parameters	Unit	Aguirre ST		Costa Sur ST	
		Unit 1	Unit 2	Unit 5	Unit 6
Fuel	Type	No. 6 fuel oil	No. 6 fuel oil	Natural Gas	Natural Gas
Maximum Capacity	MW	450	450	410	410
Minimum Capacity	MW	200	200	180	180
Fixed O&M Expense	2018 \$/kW-year	32.04	32.04	35.96	35.96
Variable O&M Expense	2018 \$/MWh	2.25	2.25	2.72	2.72
Heat Rate at Maximum Capacity	MMBtu/MWh	9.60	9.70	9.75	9.75
Heat Rate at Minimum Capacity	MMBtu/MWh	9.94	10.16	9.93	10.07
Forced Outage	%	20	20	2	4
Minimum Downtime	Hours	48	48	48	48
Minimum Runtime	Hours	720	720	720	720
Ramp Up Rate	MW/minute	5	5	5	5
Ramp Down Rate	MW/minute	5	5	5	5

Parameters	Unit	Palo Seco ST		San Juan ST	
		Unit 3	Unit 4	Unit 7	Unit 8
Fuel	Type	No. 6 fuel oil	No. 6 fuel oil	No. 6 fuel oil	No. 6 fuel oil
Maximum Capacity	MW	216	216	100	100
Minimum Capacity	MW	130	130	70	70
Fixed O&M Expense	2018 \$/kW-year	46.47	46.47	49.02	49.02
Variable O&M Expense	2018 \$/MWh	4.95	4.95	2.93	2.93
Heat Rate at Maximum Capacity	MMBtu/MWh	9.73	9.73	10.50	10.45
Heat Rate at Minimum Capacity	MMBtu/MWh	10.35	10.35	10.50	10.50
Forced Outage	%	42	42	15	15
Minimum Downtime	Hours	48	48	48	48
Minimum Runtime	Hours	720	720	720	720
Ramp Up Rate	MW/minute	3	3	3	3
Ramp Down Rate	MW/minute	3	3	3	3

Note: Aguirre ST and Costa Sur ST units have an emergency minimum capacity of 150 MW and 100 MW respectively.

Source: PREPA, Siemens.

The minimum capacity levels correspond to the minimum output that would still allow the units to return to a regulating operating mode within the hour, according to PREPA operations. There are lower capacity levels (e.g. Costa Sur ST 5&6 at 100 MW and Aguirre ST 1&2 at 150 MW), but these lower capacities would require multiple hours for the units to return to regulating operating mode.

The minimum run time reported was defined by PREPA's operations team to prevent the units from weekly cycling as was observed in prior studies that included high levels of renewable penetration.

The reported heat rates correspond to the values currently used in PREPA's models, adjusted if necessary for the reduced operating limits. These heat rates are reasonable for the technologies considered and are the best information available at this time.

For the forced outage assumption, Siemens reviewed the reported forced outage statistics for each unit from 2011 to October 2016 (reported Forced Outage Factor), in addition to the forced outage rate (FOR) currently used in PREPA's models and the recent experience with the units.

Siemens increased the outage rate of Aguirre ST 1&2 from 4 percent in PREPA's existing models to 20 percent based on both the increase in forced outages experienced during 2010-2016 and the overall unit's condition. Costa Sur ST 5 was left unchanged at 2 percent and Costa Sur ST 6 was increased slightly from 3 percent to 4 percent. Costa Sur units 5&6 are expected to be thoroughly inspected and repaired.

Palo Seco ST units 3 and 4 have had fairly poor performance and Siemens increased the FOR to 42% to be conservative and in line with the 45% availability observed. Finally, San Juan ST 7&8 outage rates were modeled at 15% to reflect 70% observed availability.

Based on discussions with PREPA staff, Siemens excluded Costa Sur ST 3&4, Palo Seco ST 1&2 and San Juan ST 9&10 with a total of 540 MW from the IRP study, because these units are not in acceptable operating condition, are not in MATS compliance, and would require large investments that do not appear to be economic, to achieve MATS compliance and working condition.

4.1.1.2 Combined Cycles Gas Turbine (CCGT)

PREPA's four Combined Cycle Gas Turbine (CCGT) units run on diesel. These units include Aguirre 1&2 CC (260 MW each) and San Juan 5&6 CC (200 MW each) with a total capacity of 920 MW. The Aguirre CCGT units went into commercial operation in 1975-1976 and are inefficient with very low historical dispatch levels. The nominal capacity of these units is 296 MW each, but this has been limited to 260 MW in this study¹⁵. These units can be economically retired in the IRP, however before the entry of a new CCGT in the south they do provide support in the case of MiniGrid isolated operations, when the load in the system could be too small for larger units like AES Coal or EcoEléctrica (in combine cycle mode) to be dispatched.

San Juan 5&6 CCGT units (also known as the San Juan Repower) began commercial operation in 2008 have a heat rate of 7,625 Btu/kWh and 7,853 Btu/kWh, respectively. These units serve as an important generation resource operating in the north of the island. Their nominal capacity is 220 MW per unit, but this is limited to 200 MW in this study.

Exhibit 4-4 shows the unit level parameters of the four CCGT units included in the IRP. The heat rates correspond to the modeled values and it is important to note that these units should preferably be able to cycle daily if necessary to integrate renewable generation. However, as shown below PREPA has determined that the current minimum run time is 120 hours (5 days) which would allow these units to cycle weekly and be off only during the weekends.

The historical outage factors (2010 to 2016) for the Aguirre CC show values on the order of 2 percent for the Aguirre CC Unit 1 and 10 percent for Aguirre CC Unit 2, possibly due to its relatively low dispatch. However, the outage factor for these units was left at 20 percent considering their recent performance, as Siemens noted that Aguirre CCGT unit 2 had fairly poor performance with 33 percent steam turbine outage in 2015 and 20 percent outage in 2016. For San Juan CC, history has shown relatively poor availability in both units but better than the prior modeled 20 percent for San Juan unit 5 and worse for San Juan unit 6 (10 percent used in prior modeling). Thus, both units are modeled in this IRP at 18 percent forced outage rate, in line with the historical values.

¹⁵ The maximum capacities considered in the study are based on information provided by PREPA.

Exhibit 4-4. CC Units Parameters (Aguirre and San Juan)

Parameters	Unit	Aguirre CC		San Juan CC	
		Unit 1	Unit 2	Unit 5	Unit 6
Fuel	Type	Diesel	Diesel	Diesel	Diesel
Maximum Capacity	MW	260	260	200	200
Minimum Capacity	MW	46	46	155	155
Fixed O&M Expense	2018 \$/kW-year	22.64	22.64	27.40	27.40
Variable O&M Expense	2018 \$/MWh	6.79	6.79	2.22	2.22
Heat Rate at Maximum Capacity	MMBtu/MWh	11.14	11.14	7.63	7.85
Heat Rate at Minimum Capacity	MMBtu/MWh	11.42	11.42	8.46	8.86
Forced Outage	%	20	20	18	18
Minimum Downtime	Hours	0	0	48	48
Minimum Runtime	Hours	2	2	120	120
Ramp Up Rate	MW/minute	5	5	3	3
Ramp Down Rate	MW/minute	5	5	3	3

Source: PREPA, Siemens.

4.1.1.3 Gas Turbines

Out of the 25 GT units, 24 units, with a total capacity of 743 MW, are included in the IRP. The GTs include Cambalache GT 2&3 (82.5 MW each), Mayagüez GT 1 through 4 (50 MW each), and nine pairs of distributed GTs (21 MW each) spread across the island. The Mayagüez units are four aero-derivative gas turbines with relatively good efficiency. The distributed GT's (21 MW each) include pairs of two units located: Dagua (2x21), Palo Seco (6x21), Aguirre (2x21), Costa Sur (2x21), Jobos (2x21), Yabucoa (2x21), and Vega Baja (2x21). These nine pair of distributed units, while in operating condition, are fairly old and have very poor heat rates. Fourteen of these units are retired early in the IRP capacity expansion plan and replaced by new peakers.

Based on discussions with PREPA staff, Cambalache GT 1 will be excluded from the IRP because it is not planned to be returned to operating condition in the foreseeable future. The two 21 MW GTs at Aguirre and two 21 MW GTs at Costa Sur are necessary to provide black-start capability to their respective combined cycle and steam turbine at each location. These gas turbines can only be retired after new units are installed with black-start capability.

Exhibit 4-5 shows the unit level parameters of the 24 GT units considered in the IRP. The heat rates and forced outages are as modeled in the PREPA's models. The distributed GTs and the Mayagüez units can cycle with zero downtime and runtime.

Exhibit 4-5. GT Units Parameters (Cambalache, Mayagüez and Nine Pairs of Distributed GT units)

Parameters	Unit	Cambalache CT		GT Units
		Unit 2	Unit 3	Each Unit
Fuel	Type	Diesel	Diesel	Diesel
Maximum Capacity	MW	83	83	21
Minimum Capacity	MW	50	50	21
Fixed O&M Expense	2018 \$/kW-year	24.44	24.44	26.54
Variable O&M Expense	2018 \$/MWh	5.52	5.52	20.19
Heat Rate at Maximum Capacity	MMBtu/MWh	11.55	11.55	14.40
Heat Rate at Minimum Capacity	MMBtu/MWh	11.55	11.55	14.40
Forced Outage	%	10.0	10.0	15
Minimum Downtime	Hours	7	7	0
Minimum Runtime	Hours	7	7	0
Ramp Up Rate	MW/minute	2	2	2
Ramp Down Rate	MW/minute	2	2	2

Parameters	Unit	Mayagüez CT			
		Unit 1	Unit 2	Unit 3	Unit 4
Fuel	Type	Diesel	Diesel	Diesel	Diesel
Maximum Capacity	MW	50	50	50	50
Minimum Capacity	MW	25	25	25	25
Fixed O&M Expense	2018 \$/kW-year	10.64	10.64	10.64	10.64
Variable O&M Expense	2018 \$/MWh	6.40	6.40	6.40	6.40
Heat Rate at Maximum Capacity	MMBtu/MWh	9.32	9.32	9.32	9.32
Heat Rate at Minimum Capacity	MMBtu/MWh	11.20	11.20	11.20	11.20
Forced Outage	%	9	9	9	9
Minimum Downtime	Hours	0	0	0	0
Minimum Runtime	Hours	0	0	0	0
Ramp Up Rate	MW/minute	6	6	6	6
Ramp Down Rate	MW/minute	6	6	6	6

Source: PREPA, Siemens.

4.1.1.4 Hydro

PREPA has 21 hydroelectric generating units at 11 generating facilities for a total installed nameplate capacity of 105 MW. However, some of these units are not operational, or are underutilized due to staffing and funding shortages resulting in deferred maintenance issues. The operational units total 34 MW with a capacity factor of less than 20 percent as of the first quarter of 2018. In an effort to alternative methods that could economically increase the output and continuing operation from these clean hydroelectric resources, PREPA issued a Request for Proposal (RFP) regarding long-term lease and energy sales agreement for their hydroelectric power plants¹⁶. Exhibit 4-6 shows a Scenario to increase hydroelectric contribution to 70 MW, assuming a high-level estimate of a total of \$100 million investment through 2023. This value of 70 MW should be considered a possible outcome of a refurbishing project, like the one considered, but larger values are possible.

¹⁶ REQUEST FOR PROPOSALS: Long-Term Lease and Energy Sales Agreement(s) for Hydroelectric Power Plants Owned by: Puerto Rico Electric Power Authority

Exhibit 4-6. PREPA Operational Hydro Capacity Assumptions

Year	2019	2020	2021	2022	2023
Capacity (MW)	34	50	70	70	70
Availability Factor	20%	40%	60%	80%	90%
Capacity Factor	15%	25%	28%	28%	28%
Annual Generation GWh	44,676	109,500	171,696	171,696	171,696

Source: PREPA, Siemens.

4.1.1.5 EcoEléctrica and AES PPOAs

To supplement its own capacity, PREPA purchases power from two co-generators under the terms and conditions of PPOAs, including 507 MW natural gas-fired combined cycle plant from EcoEléctrica, L.P. and 454 MW coal-fired steam electric cogeneration station from AES. The 961 MW of capacity provided by the two co-generators brings the total capacity available to PREPA to 5,011 MW¹⁷.

In accordance with a 22-year PPOA that commenced in March 2000, each calendar year EcoEléctrica fixes the fuel cost per million BTU for the first 76 percent of the station's capacity for that year. For capacity in excess of 76 percent, PREPA has been charged a price based upon a spot¹⁸ fuel price set by EcoEléctrica at the time the excess capacity was dispatched. The EcoEléctrica contract has a target availability factor of 93 percent, with associated capacity payments. Based on discussions with PREPA, a renewal of EcoEléctrica PPOA will be assumed in the base Scenarios of the IRP; however, the plant is subject to economic retirement, if so decided by the least cost plan. A reduction on the fixed payments is assumed after 2022.

AES's coal-fired steam electric cogeneration station began commercial operation in November 2002. The owners of the facility have entered into a PPOA with the PREPA to provide 454 MW of power for a period of 25 years. Based on discussions with PREPA, the base Scenarios of the IRP will not assume a renewal of the AES PPOA, because this is a highly probable Scenario due to the Puerto Rico Legislature consideration of stating a very strong public policy against the disposal of coal ash in local landfills.

The operational and cost parameters of the two PPOA plants are shown in Exhibit 4-7.

¹⁷ This value corresponds to the sum of the maximum capacities considered in this study and includes the GTs and 34 MW of hydro units.

¹⁸ This "spot price" is not directly related to the spot price of fuels in the market.

Exhibit 4-7. EcoEléctrica and AES Operational Parameters

Parameters	Unit	EcoEléctrica CC	AES Coal Plant	
		Unit 1	Unit 1	Unit 2
Fuel	Type	Natural Gas	Coal	Coal
Maximum Capacity	MW	507	227	227
Minimum Capacity	MW	275	166	166
Fixed O&M Expense	2018 \$/kW-year	162.05	77.96	77.96
Variable O&M Expense	2018 \$/MWh	0.00	7.09	7.09
Capital Costs	2018 \$(000)	124,226	121,499	121,499
Heat Rate at Maximum Capacity	MMBtu/MWh	7.50	9.79	9.79
Heat Rate at Minimum Capacity	MMBtu/MWh	8.31	9.93	9.93
Forced Outage	%	2	3	3
Minimum Downtime	Hours	8	48	48
Minimum Runtime	Hours	168	720	720
Ramp Up Rate	MW/minute	10	0	0
Ramp Down Rate	MW/minute	10	0	0

Year	AES Coal Plant			EcoEléctrica CC		
	Fixed O&M Costs (Nominal \$/kW)	Variable O&M Costs (Nominal \$/MWh)	Capital Costs (Nominal \$000)	Fixed O&M Costs (Nominal \$/kW)	Variable O&M Costs (Nominal \$/MWh)	Capital Costs (Nominal \$000)
2018	77.96	7.09	121,499	162.05	0.00	124,226
2019	79.83	7.26	122,916	166.40	0.00	109,621
2020	81.75	7.43	122,991	170.84	0.00	120,962
2021	83.71	7.61	108,311	194.28	0.00	140,989
2022	85.72	7.79	94,026	198.95	0.00	143,808
2023	87.78	7.98	83,779	203.72	0.00	146,685
2024	89.88	8.17	74,127	208.61	0.00	149,618
2025	92.04	8.37	74,865	213.62	0.00	152,611
2026	94.25	8.57	75,627	218.75	0.00	155,663
2027	96.51	8.78	76,390	224.00	0.00	158,776
2028	98.83	8.99	77,159	229.37	0.00	161,952
2029	101.20	9.20	77,934	234.88	0.00	165,191
2030	103.63	9.42	78,714	240.51	0.00	168,495
2031	106.11	9.65	79,502	246.29	0.00	171,864
2032	108.66	9.88	80,298	252.20	0.00	175,302
2033	111.27	10.12	81,103	258.25	0.00	178,808
2034	113.94	10.36	81,915	264.45	0.00	182,384
2035	116.67	10.61	82,735	270.79	0.00	186,032
2036	119.47	10.86	83,564	277.29	0.00	189,752
2037	122.34	11.12	84,400	283.95	0.00	193,547
2038	122.34	11.12	84,400	283.95	0.00	193,547

Source: PREPA, Siemens.

4.1.2 Utility Scale Renewable PPOAs

This section includes a summary of the projects that were considered for modeling of the renewable generators. Between 2008 and 2012, PREPA signed 68 renewable PPOAs. As of December 2018, 58 PPOAs remained in effect with a total capacity of 1,480.6 MW, out of which 11 contracts are in operation.

4.1.2.1 PPOAs in Commercial Operation or in Pre-Operation

As of December 2018, 11 PPOAs are in either commercial operation or in pre-operation (energized, under testing, and selling energy and renewable energy credits to PREPA). These projects represent 272.9 MW of capacity, including 147.1 MW of solar photovoltaic (PV), 121 MW of wind, and 4.8 MW of landfill gas.

Exhibit 4-8 shows the eight PPOAs in commercial operation as of December 2018, with a total capacity of 200.5 MW. Even though the installed capacity of Pattern Santa Isabel is 95 MW, the maximum capacity has been limited to 75 MW due to contractual limitation of compliance with the Minimum Technical Requirements (MTR).). The plant capacity could increase to 95 MW during certain months (February to September), but it has not been allowed to reach these levels as the plant currently does not meet the MTR at those levels. The plant was modeled in this IRP at 75 MW, which will continue until Pattern can show that it meets the Minimum Technical Requirements with the increased output.

Exhibit 4-8. Eight PPOAs under Commercial Operation

Ref. Number	Name	Status	Contract Number	Technology	Capacity MW
1	AES Illumina	Operation	2010-P00050	Solar	20
18	Horizon Energy	Operation	2011-P00034	Solar	10
46	San Fermin Solar (Coqui Power)	Operation	2011-P00050	Solar	20
60	Windmar (Cantera Martino)	Operation	2010-P00052	Solar	2.1
30	Yarotek (Oriana)	Operation	2011-P00048	Solar	45
32	Go Green (Punta Lima)	Operation	2010-AI0001	Wind	26
31	Pattern (Pattern Santa Isabel)	Operation	2010-P00047	Wind	75
24	Fajardo Landfill Tech (Landfill Gas Technologies of Fajardo)	Operation	2013-P00046	Landfill G	2.4
Total Capacity					200.5

Source: PREPA, Siemens.

The capacity factors for these PPOAs were derived from an assessment of the historical performance of them as shown in Exhibit 4-9. The Model Target is the forecasted capacity factor. Plant specific capacity factor estimates were derived considering the history and the fact that some years were partial operation or pre-operation.

Exhibit 4-9. Historical Capacity Factors for Eight PPOAs in Commercial Operation

Ref Number	Name		2016 Hourly	2015 5-minute	2016 5-minute	2017 5-minute	Model Target
1	AES Illumina		22%	23%	22%	24%	23%
18	Horizon		27%	19%	27%	29%	24%
24	Fajardo Landfill Tech (Landfill Gas Technologies of Fajardo)		52%				80%
30	Yarotek (Oriana)				9%	25%	25%
46	San Fermin (Coqui Power)		22%				22%
60	Windmar (Cantera Martino)		23%	25%	23%	26%	24%
		2013 Hourly	2014 Hourly	2015 Hourly	2016 Hourly	2017 Hourly	
31	Pattern (Pattern Santa Isabel)	18%	25%	27%	22%	25%	23%
32	Go Green (Punta Lima)	25%	24%	26%	22%	24%	24%

Exhibit 4-10 shows the PPOAs in pre-operation as of December 2018, with a total capacity of 52.4 MW. Humacao Solar Project, LLC is being developed in two phases: Phase 1 (20 MW) is in testing and Phase 2 (20 MW) is under construction as of December 2018. A landfill gas project, Landfill Gas Technologies of Fajardo, LLC (Toa Baja Landfill), completed testing in July of 2017 and was in the process of achieving commercial operation when hurricanes Irma and Maria struck in September 2017. It is expected that the facility will be declared in commercial operation in 2019, so the plant is considered under commercial operation in the IRP. Exhibit 4-10 lists the PPOAs under pre-operation as of December 2018.

For the existing solar PPOAs and all future solar projects, the IRP has assumed a capacity factor of 22%. This value is viewed as conservative since the historical values are slightly higher, in the 23% range. For landfill gas, a capacity factor of 80% is assumed in this IRP.

Exhibit 4-10. Three PPOAs under Pre-Operation

Ref. Number	Name	Status	Contract Number	Technology	Capacity MW
7	Fonroche Energy (Humacao Solar Project)	Pre-Operation	2012-P00031	Solar	40.0
62	Windmar (Vista Alegre/Coto Laurel)	Pre-Operation	2012-P00052	Solar	10.0
25	Toa Baja Landfill Tech (Landfill Gas Technologies of Fajardo)	Pre-Operation	2013-P00073	Landfill G	2.4
Total Capacity					52.4

Source: PREPA, Siemens.

4.1.2.2 PPOAs in Renegotiation

Of the 18 PPOAs successfully renegotiated and amended in 2013-2014, 15 have not begun construction. Between 2015 and 2016, most of these companies requested extensions to start construction and commercial operation dates established in their PPOAs. Most of the requests were related to the difficulties alleged by the companies in securing financing for their projects due to the financial situation of the Government of Puerto Rico and PREPA. Exhibit 4-11 shows the list of the PPOAs under renegotiation. The PPOAs under re-negotiation are modeled as potential new supply options (volumes and sites), assuming benchmarked new solar prices instead of the PPOAs actual prices.

Exhibit 4-11. Fifteen PPOAs under Renegotiation

Ref. Number	Name	Status	Contract Number	Technology	Capacity MW
5	Atenas Solar Farm (Desarrollos del Norte)	Re-negotiation	2013-P00070	Solar	20
3	Blue Beetle III	Re-negotiation	2012-P00037	Solar	20
4	Ciro Group (Ciro One Salinas)	Re-negotiation	2011-P00043	Solar	57
15	Grupotec USA Inc (Xzerta-Tec)	Re-negotiation	2013-P00042	Solar	20
16	Guayama Solar Farm (Guayama Solar Energy)	Re-negotiation	2011-P00042	Solar	17.8
21	Irradia Energy USA (Morovis Solar Farm)	Re-negotiation	2012-P00053	Solar	33.5
42	Moca Solar Farm	Re-negotiation	2013-P00003	Solar	20
43	North Coast Solar	Re-negotiation	2013-P00041	Solar	20
36	Renewable Energy Authority (Vega Serena)	Re-negotiation	2012-P00045	Solar	20
39	Resun (Barceloneta)	Re-negotiation	2012-P00061	Solar	20
47	Solaner	Re-negotiation	2012-P00146	Solar	25
48	Solar Blue (Solar Blue Bemoga)	Re-negotiation	2013-P00052	Solar	20
57	WindMar (Santa Rosa)	Re-negotiation	2012-P00080	Solar	20
63	YFN Yabucoa Solar (Justin Orozco)	Re-negotiation	2013-P00049	Solar	20
6	Energy Answers Arecibo	Re-negotiation	2010-AI0018	WTE	79
Total Capacity					412.3

Source: PREPA, Siemens.

With respect of the Energy Answers Arecibo PPOA project, there are a number of permitting and local opposition challenges. Among others, the Governor of Puerto Rico retired the administration endorsement to the project. Hence, this project will not be considered as part of the IRP, which is conservative, as its location on the north of the transmission system and high contribution to the RPS

would result in a favorable outcome from these two points of view. Other waste to energy technologies could be considered instead.

4.1.2.3 PPOAs not Re-negotiated

There are 32 projects with PPOAs subject to renegotiation. For the IRP, these projects provide an indication of available sites that may be utilized by alternative renewable generation projects. Exhibit 4-12 lists the 32 PPOAs which were not renegotiated. These projects were considered in the IRP as potential new supply options (capacity and sites), assuming benchmarked new prices instead of the PPOAs actual prices.

Exhibit 4-12.Thirty two PPOAs not Re-negotiated

Ref. Number	Name	Status	Contract Number	Technology	Capacity MW
41	Cabo Solar	Not Renegotiated	2013-P00069	Solar	20
44	Caracol Solar (Roma Solar) LLC	Not Renegotiated	2013-P00004	Solar	20
52	Carolina Solar (Trina)	Not Renegotiated	2013-P00067	Solar	20
10	Fonroche Energy (Humacao Solar Project)	Not Renegotiated	2013-P00048	Solar	15
9	Fonroche Energy (Solar Project Ponce)	Not Renegotiated	2013-P00045	Solar	30
12	Fonroche Energy (Vega Baja Solar Project)	Not Renegotiated	2013-P00050	Solar	15
8	Fonroche Energy (Lajas Solar Project)	Not Renegotiated	2013-P00046	Solar	10
11	Fonroche Energy (South Solar 2)	Not Renegotiated	2013-P00047	Solar	30
13	GG Alternative Energy Corp.	Not Renegotiated	2013-P00077	Solar	20
17	Hatillo Solar (Pattern)	Not Renegotiated	2013-P00074	Solar	30
19	HSEA PR Isla Solar I	Not Renegotiated	2013-P00057	Solar	40
22	Jonas Solar Farm (Jonas Solar Energy)	Not Renegotiated	2012-P000140	Solar	40
23	Juncos Solar Energy	Not Renegotiated	2012-P00138	Solar	20
26	M Solar (M Solar Generating)	Not Renegotiated	2012-P00142	Solar	50
34	REA Ceiba (REA Energy Ceiba Solar Plant)	Not Renegotiated	2013-P00076	Solar	20
33	REA Energy (Luquillo Solar Plant)	Not Renegotiated	2013-P00051	Solar	20
35	REA Hatillo (REA Energy Hatillo Solar Plant)	Not Renegotiated	2013-P00075	Solar	20
45	Sierra Solar (Roma Solar)	Not Renegotiated	2013-P00072	Solar	20
53	Vega Baja Solar Energy	Not Renegotiated	2012-P00139	Solar	30
54	Western Wind (Yabucoa Solar)	Not Renegotiated	2011-P00090	Solar	30
56	WindMar (Dorado-Toa Baja)	Not Renegotiated	2012-P00079	Solar	20
2	Aspenall Energy	Not Renegotiated	2012-P00089	Wind	10
14	GG Alternative Energy Corp.	Not Renegotiated	2013-P00071	Wind	10
50	Tradewind Energy (Tradewinds Energy Barceloneta)	Not Renegotiated	2012-P00030	Wind	75
51	Tradewind Energy (Tradewinds Energy Vega Baja)	Not Renegotiated	2012-P00028	Wind	50
55	Wind to Energy	Not Renegotiated	2011-P00101	Wind	20
58	WindMar (Dorado-Toa Baja)	Not Renegotiated	2012-P00095	Wind	44
61	Windmar (Punta Ventana)	Not Renegotiated	2008-AI0066C	Wind	18.4
59	Windmar (Punta Verraco)	Not Renegotiated	2012-P00049	Wind	34.5
49	Sunbeam	Not Renegotiated	2010-AI0031	WTE	10
37	Renewable Power Group	Not Renegotiated	2012-P00010	Landfill G	2
38	Renewable Power Group	Not Renegotiated	2012-P0009	Landfill G	1.5
		Total Capacity			795.4

Source: PREPA, Siemens.

4.1.2.4 PPOAs Assumed Contract Pricing

As indicated earlier, any project that is not in operation or pre-operation (i.e. all other projects irrespective of having re-negotiated PPOAs or not), was modeled in the IRP as potential new supply sites with commercial conditions according to Siemens forecast for new solar prices.

For the projects in operation or pre-operation, Siemens assumed the price conditions shown in Exhibit 4-13, where the Contract Price is inclusive of RECs and does not have escalation clauses.

Exhibit 4-13. Projects in Operation or Pre-operation Prices

Project Type	Contract Price \$/MWh
Solar PV	150
Wind	125
Land fill gas	100

Note: above prices include RECs and does not have escalation clauses.

4.2 Environmental Considerations

Environmental regulations have the potential to impact the overall cost and operation of electric generation. As such, compliance requirements for key environmental regulations with the potential to significantly impact portfolio costs and resource decisions need to be factored into this IRP analysis. This initial review considered existing regulations and the outlook for potential new compliance requirements over the study horizon (2019-2038). An overview of these key regulations, applicability to PREPA's existing and future portfolio and the approach to incorporate compliance into the IRP analysis are documented in this section. Although there are numerous environmental policies impacting the energy sector at the federal, state and local levels, the primary policies that are driving power markets and generation decisions are the suite of Environmental Protection Agency (EPA) rules addressing power plant emissions and state driven renewable and alternative energy portfolio standards. The environmental regulations determined by Siemens and PREPA to be potentially significant and factored into the IRP analysis include federal air regulations, water regulations, and local policy dictating targets for renewable and alternative energy, specifically:

- National Ambient Air Quality Standards (NAAQS)
- Mercury and Air Toxics Standards (MATS)
- Carbon Regulation
 - Greenhouse Gas (GHG) Emission Standards for New, Modified, and Existing Electric Generating Units
 - Outlook for potential future regulation of GHG emissions from power generators
- Puerto Rico Renewable Portfolio Standard (RPS)
- Section 316(b) of the Clean Water Act
- Puerto Rico Water Quality Standards Regulation

A summary of PREPA's generating units and applicability to the air quality regulations is presented in Exhibit 4-14.

Exhibit 4-14: Summary of PREPA Units¹⁹ and Emissions Regulatory Coverage

	Generation Units	Capacity (MW)	Fuel	SO2 EPA Final Designation	MATS Affected	Carbon Emissions
MATS Affected Units	Aguirre 1 ST	450	No. 6 fuel oil	Nonattainment	Yes	Yes
	Aguirre 2 ST	450	No. 6 fuel oil	Nonattainment	Yes	Yes
	Costa Sur 3 ST*	85	No. 6 fuel oil	Attainment/Unclassifiable	Yes	Yes
	Costa Sur 4 ST*	85	No. 6 fuel oil	Attainment/Unclassifiable	Yes	Yes
	Costa Sur 5 ST	410	Natural gas, No. 6 fuel oil capable	Attainment/Unclassifiable	Yes	Yes
	Costa Sur 6 ST	410	Natural gas, No. 6 fuel oil capable	Attainment/Unclassifiable	Yes	Yes
	Palo Seco 1 ST*	85	No. 6 fuel oil	Nonattainment	Yes	Yes
	Palo Seco 2 ST*	85	No. 6 fuel oil	Nonattainment	Yes	Yes
	Palo Seco 3 ST	216	No. 6 fuel oil	Nonattainment	Yes	Yes
	Palo Seco 4 ST	216	No. 6 fuel oil	Nonattainment	Yes	Yes
	San Juan 7 ST	100	No. 6 fuel oil	Nonattainment	Yes	Yes
	San Juan 8 ST	100	No. 6 fuel oil	Nonattainment	Yes	Yes
	San Juan 9 ST*	100	No. 6 fuel oil	Nonattainment	Yes	Yes
	San Juan 10 ST*	100	No. 6 fuel oil	Nonattainment	Yes	Yes
Combined Cycle	Aguirre 1 CC	260	Diesel	Nonattainment	No	Yes
	Aguirre 2 CC	260	Diesel	Nonattainment	No	Yes
	San Juan 5 CC	200	Diesel	Nonattainment	No	Yes
	San Juan 6 CC	200	Diesel	Nonattainment	No	Yes
Gas Turbine	Cambalache 2 GT	83	Diesel	Attainment/Unclassifiable	No	Yes
	Cambalache 3 GT	83	Diesel	Attainment/Unclassifiable	No	Yes
	Mayagüez 1 GT	50	Diesel	Attainment/Unclassifiable	No	Yes
	Mayagüez 2 GT	50	Diesel	Attainment/Unclassifiable	No	Yes
	Mayagüez 3 GT	50	Diesel	Attainment/Unclassifiable	No	Yes
	Mayagüez 4 GT	50	Diesel	Attainment/Unclassifiable	No	Yes
	Daguao 2 GTs	42	Diesel	Attainment/Unclassifiable	No	Yes
	Palo Seco GT11, 12	42	Diesel	Nonattainment	No	Yes
	Palo Seco GT21, 22	42	Diesel	Nonattainment	No	Yes
	Palo Seco GT31, 32	42	Diesel	Nonattainment	No	Yes
	Aguirre GT21 & 22	42	Diesel	Nonattainment	No	Yes
	Costa Sur GT11, 12	42	Diesel	Attainment/Unclassifiable	No	Yes
	Jobos GT11, 12	42	Diesel	Attainment/Unclassifiable	No	Yes
	Yabucoa GT11, 12	42	Diesel	Attainment/Unclassifiable	No	Yes
	Vega Baja GT11, 12	42	Diesel	Attainment/Unclassifiable	No	Yes
Hydro	Hydro (various)	34	Water	NA	No	No
IPP units	AES Coal Plant	454	Coal	Attainment/Unclassifiable	Yes**	Yes
	EcoEléctrica Plant	507	Natural Gas	NA	No	Yes

* Costa Sur 3 and 4 ST, Palo Seco 1 and 2 ST, and San Juan 9 and 10 ST listed here will not be included in the IRP analysis as future generating resources.

**MATS affected unit, however, PREPA is not responsible for compliance with MATS

Source: EPA, PREPA, Siemens

4.2.1 National Ambient Air Quality Standards (NAAQS)

The U.S. EPA sets standards for six criteria pollutants²⁰ under the Clean Air Act (CAA) and is required to regularly review and update these standards as necessary. Particulate matter, nitrogen oxides and sulfur dioxide (SO₂) are criteria pollutants emitted from fossil fuel combustion. Ozone levels can indirectly be impacted by fossil fuel emissions. No recent changes have been made to NAAQS for particulate matter and nitrogen oxides. Although the potential for these standards to

¹⁹ Cambalache 1 GT, an 83MW diesel fired gas turbine, is currently out of service and is not assumed to be operational in the future in the IRP.

change exists over the study horizon, no specific assumptions around these potential changes were made in modeling, given the uncertainty and overall expectation that the portfolio will become less fossil fuel based in the coming years.

4.2.2 SO₂ NAAQS

In January of 2018, EPA updated attainment designations for SO₂ for areas in Puerto Rico based on air quality modeling. The 1-hour SO₂ standard of 75 parts per billion was finalized in June 2010; however, the latest round of designations was published in January 2018 and became effective in April 2018. Several areas in Puerto Rico were designated as non-attainment areas, meaning that they were found not to meet the SO₂ standard. Other areas in Puerto Rico were designated as being in attainment or otherwise not able to be classified at this time. The designations are based on emissions from all sources of SO₂ emissions including transportation and industrial fuel use. For the IRP, the environmental review is focused on emissions from electric generating units. The combustion of coal- and petroleum-based fuels releases SO₂ emissions. Area designations for Puerto Rico are shown in the exhibits below.

Exhibit 4-15: Puerto Rico San Juan Area SO₂ Designations



Source: EPA

²⁰ The six criteria pollutants are ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide, and lead.

Exhibit 4-16: Puerto Rico Guayama Salinas Area SO₂ Designations

Source: EPA

In the San Juan area, the San Juan and Palo Seco generating facilities represent significant SO₂ emitting sources in the area. Actual historic emissions reported by PREPA are presented in Exhibit 4 17. Several industrial facilities emitting SO₂ are located in the San Juan area, all of which are reported by the EPA to emit less than 35 tons SO₂ annually. The San Juan Luis Munoz Marin Airport is also located in the San Juan area and is designated as a moderate source with annual emissions reported at 586 tons SO₂ in 2014. Another potentially large source of emissions in the area are the port and mobile sources such as is ship and vehicle traffic. In the Guayama Salinas area, the Aguirre generating facility is the most significant source contributor in the area. No other specific point sources were included in the Guayama Salinas area modeling analysis performed by the EPA in developing these designations. Aguirre historical emissions are also included in Exhibit 4 17.

Exhibit 4-17: Actual Reported SO₂ Emissions for PREPA Units in Nonattainment Areas (tons SO₂)²¹

Facility	Area	2013 Emissions	2014 Emissions	2015 Emissions
San Juan	San Juan	5,307	5,135	6,063
Palo Seco	San Juan	5,700	3,128	2,979
Aguirre	Guayama Salinas	9,640	9,261	9,585

Source: PREPA, EPA Technical Support Document Chapter 36, Final Round 3 Area Designations for the 2010 1-hour SO₂ Primary National Ambient Air Quality Standard for Puerto Rico

Units emitting SO₂ located in areas designated as attainment or unclassifiable will still continue to monitor and report emissions to the EPA, but do not otherwise have to alter operations at this time.

Units emitting SO₂ located in areas designated as nonattainment are required to be included in an SO₂ State Implementation Plan (SIP) that must be submitted to the EPA by Puerto Rico and finalized by October 2019. The Puerto Rico Environmental Quality Board (EQB) will develop the SIP, which will lay out a plan for how the nonattainment areas will achieve compliance with the SO₂ standard by 2023. Options for compliance for generating units include installation of sulfur emission control technology, fuel switching, or ceasing or reducing operations. Nonattainment designated areas are also subject to Nonattainment New Source Review requirements for permitting new and modified SO₂ emitting facilities in these areas.

PREPA units in locations classified as nonattainment for SO₂ are presented in the Exhibit below:

²¹ Note that none of the PREPA units are equipped with continuous emission monitoring (CEMS). Emissions are estimated based on fuel specifications and hours of unit operation as reported by PREPA to the Puerto Rico EQB.

Exhibit 4-18: PREPA Units Included in Nonattainment SO₂ Standards Designation Areas

Area	Generation Units	Capacity (MW)	Fuel	SO ₂ EPA Final Designation
Guayama Salinas	Aguirre 1 ST	450	No. 6 fuel oil	Nonattainment
	Aguirre 2 ST	450	No. 6 fuel oil	Nonattainment
	Aguirre 1 CC	260	Diesel	Nonattainment
	Aguirre 2 CC	260	Diesel	Nonattainment
	Aguirre GT21 & 22	42	Diesel	Nonattainment
San Juan	Palo Seco 1 ST	85	No. 6 fuel oil	Nonattainment
	Palo Seco 2 ST	85	No. 6 fuel oil	Nonattainment
	Palo Seco 3 ST	216	No. 6 fuel oil	Nonattainment
	Palo Seco 4 ST	216	No. 6 fuel oil	Nonattainment
	Palo Seco GT11 & GT12	42	Diesel	Nonattainment
	Palo Seco GT21 & GT 22	42	Diesel	Nonattainment
	Palo Seco GT31 & GT32	42	Diesel	Nonattainment
	San Juan 5 CC	200	Diesel	Nonattainment
	San Juan 6 CC	200	Diesel	Nonattainment
	San Juan 7 ST	100	No. 6 fuel oil	Nonattainment
	San Juan 8 ST	100	No. 6 fuel oil	Nonattainment
	San Juan 9 ST	100	No. 6 fuel oil	Nonattainment
	San Juan 10 ST	100	No. 6 fuel oil	Nonattainment

Source: EPA, PREPA

Details on the Puerto Rico SIP will be updated by the results of the IRP analysis. The IRP will track SO₂ emissions from each portfolio and offer options for fuel switching (i.e. should natural gas become available in the north) and operational changes (i.e. minimum run or retirement and replacement with lower emitting generation options) to existing units. Facility-level operation and emissions resulting from the preferred portfolios will be provided to the Puerto Rico EQB. At this time, the following assumptions in the IRP analysis are expected to support emission reductions from these facilities:

- Palo Seco steam units 1 and 2 will not be assumed as future generating resources in the IRP analysis.
- San Juan steam units 9 and 10 will not be assumed as future generating resources in the IRP analysis.

4.2.3 Mercury and Air Toxics Standards (MATS)

The EPA regulates emissions of hazardous pollutants from electric generating units. EPA's Mercury and Air Toxics Standards (MATS), originally issued in February 2012, imposes emission reductions of mercury, acid gases, and particulate matter, and also requires subject facilities to comply with work practice standards. This is a technology-forcing regulation with no allowance trading. The rule came into effect in April of 2015 and existing plants can apply for a one year extension to reach compliance. PREPA applied for and received a one-year compliance extension for Aguirre. The

MATS rule sets a decision point for generators – control or retires – even if cost drivers may come after 2016.

Several groups filed lawsuits challenging various aspects of the MATS rule, including the EPA's determination that it was appropriate and necessary to regulate emissions from power plants. On June 29, 2015, the Supreme Court of the United States found it unreasonable that the EPA did not consider costs in its initial finding that it was appropriate and necessary to regulate these emissions,²² and the case was remanded to the D.C. Circuit Court of Appeals for further review. The D.C. Circuit remanded the proceeding to EPA to make a finding on the costs issue without vacating the MATS rule, and the MATS rule remains in effect. In April 2016, EPA published a final supplemental finding that it is appropriate and necessary to regulate hazardous air pollution from coal and oil fired steam EGUs, finding that the consideration of costs does not alter its initial finding that these emissions are necessary to regulate.²³ Therefore, steam coal- and oil-fired power plants continue to be legally obligated to meet the MATS standards.

PREPA units subject to MATS are presented in the exhibit below and the approach taken by each unit to comply with MATS.

²² *Michigan et al. v. Environmental Protection Agency et al.*, 135 S.Ct. 2699 (2015).

²³ On December 27, 2018, EPA proposed to revise the April 2016 supplemental cost finding for MATS in order to correct what EPA deems to be flaws in the analysis. EPA proposes to determine that it is not "appropriate and necessary" to regulate hazardous air pollutant emissions from power plants under Section 112 of the CAA. EPA's proposal also states that the emission standards and other requirements of the MATS rule would remain in place, since EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under Section 112 of the Act at this time. However, EPA requests comment on whether the EPA has the authority or obligation to delist the source category and rescind the standards, or to rescind the standards without delisting.

Exhibit 4-19: PREPA Existing Units Subject to MATS

	Generation Units	Fuel	MATS Compliance Status
MATS Affected Units (PREPA Responsible for Compliance)	Aguirre 1 ST	No. 6 fuel oil	No quarterly test performed until Q4 2018 ⁽¹⁾
	Aguirre 2 ST	No. 6 fuel oil	No quarterly test performed until Q4 2018 ⁽¹⁾
	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 Sur 4 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 Sur 5 ST	Natural gas(No. 6 fuel oil capable)	MATS compliant – now operating on natural gas
	Costa Sur 6 ST	Natural gas(No. 6 fuel oil capable)	MATS compliant – now operating on natural gas
	Palo Seco 1 ST	No. 6 fuel oil	Designated as limited-use unit but has exceeded heat-input threshold for limited use. 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	Designated as limited-use unit but has previously exceeded heat-input threshold for limited use. 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	PM emissions above MATS limit ⁽²⁾
	Palo Seco 4 ST	No. 6 fuel oil	This unit is currently not operating ⁽²⁾
	San Juan 7 ST	No. 6 fuel oil	Designated as limited-use unit but has exceeded heat-input threshold for limited use units. Modeled as running for reliability considerations in place of San Juan 9 ⁽²⁾
	San Juan 8 ST	No. 6 fuel oil	Designated as limited-use unit but has exceeded heat-input threshold for limited use units. Modeled as running for reliability considerations in place of San Juan 10 ⁽²⁾
	San Juan 9 ST	No. 6 fuel oil	PM emissions above MATS limit. Will not be considered as a future generating resource in the 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
MATS Affected Units (PREPA not Accountable for Compliance)	AES Coal Plant	Coal	Power Purchase - PREPA is not responsible for MATS compliance, AES represents that the plant is MATS compliant

Aguirre 1 & 2 are the largest single units in the system and are required to meet the load. Aguirre 1 & 2 can be made MATS compliant by their conversion to natural gas or can be retired (or designated limited use), when new generation is installed in the system.

These units in the north of the island are required to manage transmission limitations and can be retired (or designated limited use) when new generation is commissioned in the north.

Source: EPA, PREPA

The IRP analysis includes the following for MATS affected units:

- Aguirre units 1 and 2 are currently operating and are not MATS compliant. At this time, these units are required for reliability. Future resource portfolios will assume that these units only operate as needed for reliability purposes and then cease their operations as a means to comply with MATS. Conversion to natural gas was included as an option in Scenario 5. These units continue to operate under a 1999 consent decree with EPA. Additional action may be required pending the EPA's review of the results of the IRP. The IRP assumes that the units could run until 2025, when new large combined cycle plants could be in service.
- Costa Sur units 5 and 6 are complying with MATS by fuel switching, operating on natural gas. As of May 2018, these units began operating on natural gas. However, the permit still allows the units to operate on no. 6 fuel oil.

- Costa Sur steam units 3 and 4 and Palo Seco steam units 1 and 2 are not currently in operation and will not be considered as future generating resources in the IRP.
- Palo Seco Unit 4 and San Juan Unit 10 are currently not in operation. Palo Seco unit 3 and San Juan unit 9 have had PM emissions above the MATS limit and are run for reliability needs. San Juan Units 7-8 are designated as limited use units, which do not have to meet the MATS emission limits but must comply with certain work practice standards. San Juan Units 7-8 have previously exceeded the heat input limit for limited-use units, which require them to operate at less than eight percent capacity factor, averaged over 24-month block periods. San Juan units 9 and 10 will not be considered as a future resource in the IRP. The IRP assumes that the units could run until 2025, when new large combined cycle plants could be in service.
- New generating units included in the portfolio analysis are assumed to be MATS compliant.

Limited use and retirement options are also included in assessing portfolio options. PREPA will not consider investing in costly emission controls as a compliance option and therefore this was not considered in this analysis.

Other operational adjustments to comply with MATS have been considered but have been deemed through detailed conceptual analysis not to be viable compliance strategies for PREPA's units. Fuel blending was one compliance strategy assessed, as well as operational adjustments including infrequent soot blowing, higher burn point temperatures, and excess oxygen adjustments. Combinations of these operational adjustments have, albeit with significant challenges, enabled Hawaiian Electric Company (HECO) to comply with MATS. Characteristics of PREPA's units relative to HECO's units render them unsuitable to comply through these operational adjustments, including their larger size, lower burn temperatures, presence of continuous emission monitoring systems, mandated frequent soot blowing and higher average load levels. HECO also found fuel blending not to be a viable compliance strategy for its units. MATS compliance through fuel blending with ultralow sulfur diesel was considered by PREPA but was determined not to be a viable compliance option for MATS affected units in Puerto Rico based on PREPA's independent evaluations. In addition, based on information provided by PREPA, MATS compliance through operational modifications is not an option for the steam units.²⁴

4.2.4 Carbon Regulation

No economy-wide national regulation of carbon emissions exists in the U.S. at this time. In December 2009, EPA finalized its endangerment finding for GHG emissions from mobile sources, officially giving it the authority to regulate these emissions under the Clean Air Act (CAA). Beginning January 1, 2010, major stationary sources were required to track and report their annual GHG emissions to EPA. The EPA has issued regulations regulating the GHG emissions of new, modified, and existing electric generating units. An overview of these regulations, current status and applicability to this IRP are presented below.

²⁴ Memorandum, "Staff Opinion – Assessment of Fuel Blending for MATS Compliance", Puerto Rico Electric Authority, July 25, 2018

4.2.5 New Source Performance Standards for GHGs for Electric Generating Units

In October 2015, EPA finalized New Source Performance Standards (NSPS) for Electric Utility Generating Units under §111(b) of the CAA, a proposed regulation that would establish carbon dioxide (CO₂) emission limits for certain new, modified, and reconstructed power plants in the U.S. The NSPS applies to new, reconstructed, or modified steam EGUs and to new or reconstructed natural gas combustion turbines. The NSPS sets a rate limit of 1,000lbs of CO₂/MWh for combined cycle natural gas plants and a limit of 1,400lbs of CO₂/MWh for coal plants. The NSPS effectively prevents the permitting of new coal-fired power plants that are not equipped with CO₂ pollution control equipment such as carbon capture and sequestration (CCS), a technology that has yet to be deployed on a commercial scale.

In December 2018, EPA issued a proposed rule to amend the Section 111(b) standards for GHGs. The main feature of this proposal is that it would change the best system of emission reduction (“BSER”) and emissions standards for steam EGUs. EPA did not propose changes to the NSPS for newly constructed or reconstructed natural gas stationary combustion turbines, as a part of the proposal.

Even if the rule is not amended, it is not anticipated to have a significant impact in PREPA’s future generation portfolio. No new coal is expected. Even in the absence of this rule, Pace Global does not expect any build out of additional coal capacity in the near future. Other natural gas and fossil fuel fired units would be expected to need to meet these new source standards.

4.2.6 Clean Power Plan and Affordable Clean Energy Rule – GHG Emissions Guidelines for Existing Electric Generating Units

In October 2015, EPA finalized the Clean Power Plan (CPP), which established emissions guidelines for certain existing electric generating units under §111(d) of the CAA. The CPP established state by state emission targets for affected existing generation units. Under the CPP, states would determine the approach to meet their emissions goal, including choosing to comply as a rate goal (lb. CO₂/MWh) or a mass goal (short tons of CO₂). Overall, the aggregate state goals (on a mass basis) would reduce emissions from affected sources by an estimated 32% below 2005 levels by 2030. The initial compliance period would have begun in 2022, with the final reduction goal to be achieved by 2030. Trading of emissions between states would be encouraged under the CPP. It should be noted that Puerto Rico was not covered under the final CPP. Draft standards for existing generators located on Indian Country and in the U.S. Territories, including Puerto Rico, were released in 2014, but were never finalized. The final CPP noted that additional data would be needed to define final standards for these areas.

In February of 2016, the Supreme Court granted a request to stay the CPP while the courts rule on the legal challenges to the rule, rendering the rule and all associated planning deadlines not in effect until further notice. Further, the Trump Administration directed the EPA to perform a detailed review of the rule in a March 2017 Executive Order. This review resulted in a proposal to withdrawal the CPP in its entirety. Moreover, on August 31, 2018, EPA published the Notice of Proposed Rulemaking for the rule to replace the CPP—the “Affordable Clean Energy” or “ACE” rule. The Proposed ACE rule to replace the Clean Power Plan also currently proposes that emissions guidelines would not apply to Puerto Rico. However, until the final proposal is issued, the regulatory status remains uncertain.

Given the pending proposals to withdraw and replace the CPP, a great deal of uncertainty exists at this time over the future of regulations covering CO₂ emissions from existing power generators. Because Puerto Rico was not regulated under the final CPP and the prevailing expectation is that the

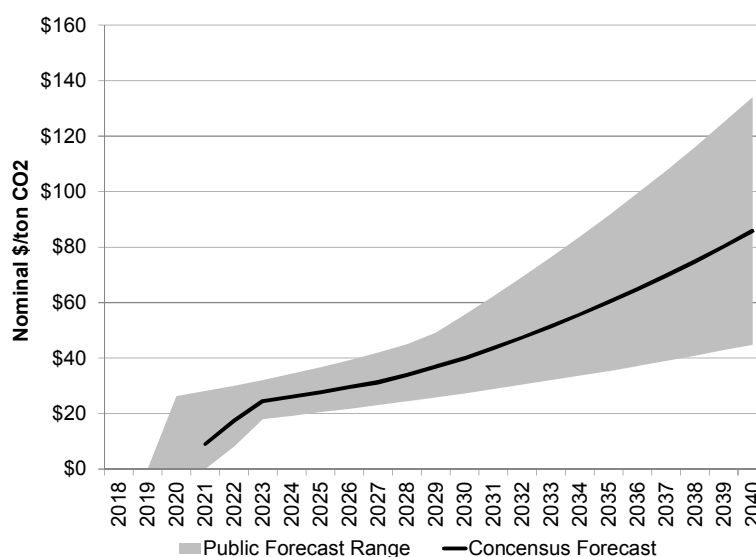
CPP rule will be withdrawn in its entirety, the CPP does not impact this IRP. Sensitivity analysis considered for this IRP would assess the impacts of a policy placing a price on carbon in the IRP.

4.2.7 Consideration of the Effect of Future Regulation of Carbon on Generators in Puerto Rico

Despite the absence of the CPP or any other national regulation of carbon emissions from power generators at this time, the potential for enactment of such regulation over the study horizon remains. To account for this uncertainty in the IRP analysis, sensitivities could be considered in supplemental analysis to include a price on CO₂ emissions from fossil generators.

This price on carbon is not intended to represent a specific view on an expected future national carbon program. The structure, timing, and resulting requirements of a potential future program are not known at this time. Rather this price could represent a future carbon trading or carbon tax policy and is intended to analyze the implications that a price on carbon would have on PREPA's portfolio operation and resource decisions. The carbon price considered for the potential sensitivity analysis is based on variety of publicly available sources and is presented in the exhibit below along with the range of pricing represented in public sources referenced.

Exhibit 4-20: Carbon Price – Carbon Regulation Sensitivities



Source: U.S. Energy Information Administration, Synapse, IHS, Siemens

4.2.8 Puerto Rico RPS

Renewable Portfolio Standards (RPS) are regulated programs placing an obligation on electricity suppliers that a certain percentage of their electricity sold be derived from alternative or renewable energy resources. At this time, 29 states, Puerto Rico, and the District of Columbia have enacted mandatory state-level RPS requirements. These RPS rules dictate expansion options and economics.

Puerto Rico established by Act 82-2010 an RPS in July of 2010 which set minimum targets of renewable and alternative energy. This rule requires that load serving entities to supply increasing shares of retail sales with qualified renewable and alternative source. This can be procured by direct

purchase of the energy including renewable attributes or by the purchase of renewable energy certificates (RECs), which are tradable instruments representing the renewable attributes qualified generation, unbundled from the energy itself. RECs allow for compliance flexibility and can be banked for use up to two years forward. The RPS targets set forth by the legislation are below. PREPA may set interim goals to meet these prescribed levels. Current law establishes compliance as a percent of purchased REC's of qualifying renewable generation vs total sales, subject to certain grounds for permissible non-compliance.

- 12 percent – 2015 through 2019
- 15 percent – 2020 through 2027
- 20 percent – 2035 and beyond

Eligible renewable generation technologies include wind, solar, geothermal, renewable biomass or biofuel, new hydropower. Alternative renewable energy generation technologies that can also be used to meet the requirement include landfill gas, fuel cells, and municipal solid waste. The rules around the use of net metered renewable energy for RPS compliance are unclear. To date, PREPA is not permitted to use RECs from distributed solar installations for RPS compliance. To be conservative in the IRP, it will be assumed that behind the meter renewables will not count towards RPS requirements, unless advised from PREPA otherwise.

The RPS to date has not been met. RECs that PREPA does purchase under renewable purchase agreements generally range from \$2 to \$4/MWh and include wind and solar photovoltaic generating facilities.

The LTCE had as an input compliance with the current RPS and we also assess the ease or difficulty that the various plans would have to reach 50% penetration.

4.2.9 Clean Water Act Section 316(b)

The EPA issued the final standards for cooling water intake structures under Section 316(b) of the Clean Water Act in May 2014. This rule aims to reduce the impingement and entrainment of marine life from the impacts of water intake structures. This rule applies to industrial facilities, including electric generation facilities, that intake water for operation from bodies of water (i.e. lakes, rivers, estuaries, and oceans) exceeding two million gallons per day and of which 25 percent is used exclusively for cooling purposes. Covered facilities are required to obtain a National Pollutant Discharge Elimination System (NPDES) permit. Further requirements are based on water withdrawal levels.

- 2 million gallon per day – action to reduce the adverse impact to marine life including control technologies like velocity screens and implement biological impact monitoring at the intake structures
- 125 million gallon per day – additional assessments of impacts required to assess permit requirements
- New systems – review on facility will be conducted to assess controls needed, this applies to new facilities and expansions at existing facilities that would significantly increase water intake volumes

Noting the unique design of individual facilities, the rule is not prescriptive of controls required, rather assigns the permitting agencies the ultimate discretion in individual facility requirements.

All PREPA generating facilities operate under site-level NPDES permits. Through these permits, information requested to assess facility control needs to comply with 316(b) are being considered. Any new or facility expansions that impact water intake will be designed to comply with requirements under 316(b).

4.2.10 Puerto Rico Water Quality Standards Regulation

Section 304(a) of the CWA requires the EPA to publish water quality criteria based on the latest scientific review. These criteria can then be used by states to adopt or build on to define state specific water quality standards as a requirement of the CWA under Section 303(c).

The Puerto Rico EQB publishes and maintains Water Quality Standards Regulation to protect preserve, maintain and enhance the quality of water in Puerto Rico compatible with the social and economic needs of the Commonwealth. The latest standards were updated in April 2016. Specifically, this regulation designates uses for bodies of water, define water quality standards, identify rules and standards applicable to sources of pollution, and establish other measures deemed necessary to maintain water quality.

All existing generation facilities that have intake cooling water, discharge, or otherwise trigger requirements under the Water Quality Standards Regulation operate under NPDES permits. These permits document facility specific requirements and tolerances based on the applicable regulation and further informed by stakeholder input. Permitting for new facilities is outside of the scope of the IRP. However, new generation options considered as a part of the IRP analysis will assume reasonable levels of controls that would expected to comply with applicable water quality requirements for new sources in Puerto Rico.

Resource Needs Assessment

5.1 Overview of the Needs

Resource planning is a multifaceted and technically complex process for most utilities. However, Puerto Rico and PREPA have a particularly complex resource planning environment due to numerous factors, including the isolated island operation without electrical or fuel delivery connections to other locations, the significant age and poor condition of much of the existing generation fleet, the uncertainty of the future economic conditions which greatly impact the electric generation requirements, and the vulnerability of the territory to catastrophic weather events. While many utilities are looking for ways to make incremental changes to their system to enhance their resiliency, the devastation to PREPA's electrical infrastructure from the 2017 Hurricanes forced PREPA to rethink its entire system design including resource planning. This IRP, following on the heels of one of the worst storm related outages experienced by an electric utility, offers PREPA an opportunity to define a sharp and significant improvement in direction for the future energy supply of Puerto Rico.

Further to the above, 2019 IRP is not a classical IRP designed to identify the least cost approach to address the expected gap between load and resources and maintaining a desired Planning Reserve Margin (PRM), but rather produce a plan that satisfies the objectives of being customer centric, financial viability, reliability and resiliency and economic growth, on a context of significant declines in the load.

Thus, this IRP is designed instead, to address the following resource needs:

- a) Address the impacts of an aging generation infrastructure that burns costly liquid fuels (mostly heavy fuel oil), which has poor reliability, does not meet environmental regulations (e.g. MATS) and is inflexible, which limits the incorporation of renewable resources.
- b) Achieve a reduction of cost of supply by the incorporation of renewable resources and take advantage of the currently observed and forecasted reduction in cost.
- c) Achieve compliance with RPS mandate. However, Siemens observed that economies alone justified greater levels of penetration.
- d) Shift from centralized generation located in the south of the island to a more decentralized generation mix, with resources across the island.

Taking in consideration the above, through input received during a series of Stakeholder Workshops, discussion with PREPA staff and Siemens own knowledge and experience with resource planning, the PREPA and Siemens project team defined a number of aspects that the resource planning resulting from this IRP must address. These needs included but were not limited to:

- Reduce the dependence on an aging, inflexible and not reliable fleet and move away from the reliance on large, concentrated generating plants.
- Improve the overall resiliency of the system to better enable Puerto Rico to withstand and recover from future severe weather and other disruptive events.
- Improve the sustainability of the electrical end use and supply.
- Determine the role of natural gas in PREPA future resource supply.
- Include in the analysis, the uncertainty associated with load, fuel costs and costs of supply technologies.
- Create a resource plan that addresses the needed changes while balancing the cost of service to customers.
- Deliver a transparent planning process that allows stakeholders to review and understand the planning process and recommendations.

In the balance of this section Siemens present the strategies, Scenarios and sensitivities used to formulate the multiple long term capacity expansion plans to address the needs above.

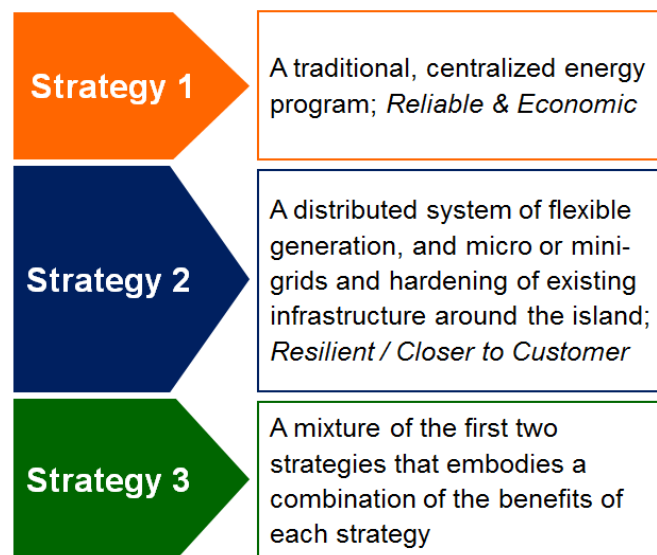
5.2 Three Strategies

As part of the stakeholder process, Siemens shared three potential strategies for consideration as shown below.

Strategy 1 reflects a traditional and centralized energy program that emphasizes reliability and economic metrics.

Strategy 2 reflects a distributed system of flexible generation, and micro or mini-grids and hardening of existing infrastructure around Puerto Rico, which emphasizes resiliency and closeness to the customer. In this strategy, most of the load is supplied from local supply resources that can be isolated from the remainder of island during a major event but still supply all or a portion of the nearby load. It is defined in terms of a minimum level of the load to be supplied by local resources (e.g., 80%).

Strategy 3 reflects a hybrid of the first two strategies that embodies a combination of the benefits of Strategy 1 and Strategy 2. In this strategy, economies of scale are taken advantage of, and some of the load may be served under normal conditions from remote resources. In this strategy, the potential for greater levels of rotating load shed during a major event is greater than Strategy 2 but should result in lower operating costs.

Exhibit 5-1. PREPA IRP Strategies

To achieve the vision of a more renewable, resilient, and reliable Puerto Rico electric system, the IRP incorporates analysis of mini-grids, micro-grids, and grid modernization to systematically improve resiliency with pockets of critical loads served by distributed resources that can operate in both grid-connected and island modes. These mini-grids are proposed to be strategically sited to support clusters of critical transmission and distribution voltage loads, downstream of distribution and transmission vulnerabilities. The IRP seeks to balance low cost reliable operation under normal conditions and the ability to mitigate and achieve timely recovery from major disruptive events.

Stakeholders generally reached consensus that a strategy founded on distributed rather than centralized supply resources is more appropriate to Puerto Rico's situation because it provides a more resilient grid. Generally, participants viewed Strategy 3 ("hybrid strategy" of centralized and distributed generation) as a short- or medium-term step to Strategy 2 (a long-term mix of distributed and flexible generation in Puerto Rico where supply is located closer to load). Most stakeholders did not support pursuit of the centralized Strategy 1, except possibly as a reference point for comparison. On the other hand, some stakeholder groups requested that Strategy 1 be explicitly modeled as this strategy was thought to likely provide the least cost configuration. Larger centralized resources aligned with Strategy 1 were incorporated in the Scenario that has all resources competing to provide the desired cost comparison information.

In addition to the IRP Regulation effective since April 24, 2018, the PREB issued orders on September 5 and September 18, 2018, regarding Scenarios and other points of the IRP, including, but not limited to, a directive to consider Strategy 1. The regulation and orders speak for themselves, so they will not be summarized here, although they are referenced below.

For each strategy, a combination of assets was developed by putting constraints on the generation, transmission, and distribution assets that are available to Puerto Rico for a specific strategy. For example, a fully distributed strategy did not consider traditional high capacity generating assets such as large gas fueled combined cycle plants or diesel fueled assets. A partially distributed system or hybrid system considered only a limited amount of larger traditional generators.

5.3 Uncertainties

In addition, the IRP captures a series of uncertainties, including load growth, Distributed Energy Resources (DER), O&M²⁵ and capital costs of assets, fuel availability and price forecasts, energy policy and permitting, weather, energy efficiency, and PPOA termination or extension. The Scenarios and sensitivities are designed to test each strategy against a combination of these uncertainties. The Scenarios, sensitivities, and stochastics (for uncertainties assessment) are discussed below.

5.4 Scenarios

The PREB IRP Regulation defines Scenarios as a combination of system requirements needed to serve load, commodity prices, capital costs, and risks that influence the choice of resources serving PREPA's future load. Each Scenario constitutes a possible resource plan. Traditional uncertainties (e.g., load forecasts, fuel forecasts, and renewables capital costs) are assessed via cases (High, Base and Low) and sensitivities. They could also be assessed via stochastic analysis. Based on extensive stakeholder engagement and consolidation of the September Scenarios orders by PREB, PREPA considered a total of six Scenarios as part of the 2018 IRP.

With respect of fuel infrastructure and renewables, the following Scenarios are considered as outlined in Exhibit 5-2 and further described below.

- Scenario 1:** No new gas-fired generation is installed. The Scenario uses the base case assumptions of solar and storage costs and availability.
- Scenario 2:** Gas to North: The land-based LNG at San Juan in the North is assumed to acquire the required permitting approval. The Scenario uses the base case assumption of solar and storage costs and availability.
- Scenario 3:** Gas to Yabucoa (east) and to Mayagüez (west) through ship-based LNG and gas to the north is supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approval. The Scenario assumes the deeper drop (NREL Low Case) of solar and storage costs coupled with high availability of renewables (early ramp up).
- Scenario 4:** Gas to Yabucoa (east) and to Mayagüez (west) through ship-based LNG and gas to the north is supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approval. The Scenario uses the base case assumption of solar and storage costs and availability.
- Scenario 5:** Aguirre Offshore Gas Port (AOGP), gas to Yabucoa (east) and to Mayagüez (west) is supplied through ship-based LNG. Gas to the north is supplied through land-based LNG at San Juan which is assumed to achieve required permitting approval. The Scenario uses the base case assumption of solar and storage costs and availability. The Scenario also places no restriction on the size of the combined cycle units (CCGT) and up to H-Class (449 MW) could be added. All previous Scenarios had a maximum size of 302 MW F-Class CCGT.

²⁵ Operation and maintenance

ESM: Energy System Modernization (ESM); this is a plan advanced by PREPA and that includes a set of pre-defined investments decisions that considers ongoing RFP processes. The ESM is benchmarked against the formulated least cost plans. The investments included in the ESM plan reported include adjustments made during the analysis carried out under the IRP.

Exhibit 5-2. PREPA IRP Scenario Definition

Scenario	New Gas				Renewable & Storage	
	AOGP	Land-based LNG at San Juan	Ship-based LNG at Yabucoa	Ship-based LNG at Mayagüez	Costs	Availability
1	No	No	No	No	Reference	Reference
2	No	Yes	No	No	Reference	Reference
3	No	Yes	Yes	Yes	Low	High
4	No	Yes	Yes	Yes	Reference	Reference
5	Yes	Yes	Yes	Yes	Reference	Reference
ESM	No	Yes	Yes	Yes	Reference	Reference

Some of the ESM decisions above are fixed and not subject to the LTCE selection. This includes the land based LNG terminal at San Juan and a new 302 MW Combined Cycle Gas Turbine (CCGT) by 2025 (or as early as possible); this will follow the conversion of San Juan 5&6 to gas, which is supported by the ship-based LNG that will be replaced by the land-based when commissioned. At Yabucoa a Ship-Based LNG terminal is to be developed and 302 MW CCGT is installed by 2025 (or as early as possible). At Mayagüez, a Ship-Based LNG terminal is developed, but the only fix decision is to convert the existing Aero units to be able to burn natural gas. The possibility of installing a CCGT is left as an option for the optimization process. The ESM also includes an additional smaller plant of approximately 100 MW in the north (modelled as 3x38 MW small CCGT) that can burn both natural gas and LPG (liquefied petroleum gas).

The following conditions and assumptions, unless specifically indicated to the contrary, will be modeled across all five Scenarios and the ESM:

1. Load Forecast is treated via a Base, High and Low case. A stochastic analysis could be conducted as a follow-up analysis; however, as will be discussed later in this report, the High and Low cases allow identifying the decisions that would be affected by changes in the load growth and the path to account for this uncertainty.
2. Fuel forecast and costs of renewable and storage are treated via sensitivities and the modification on decisions identified.
3. The AES PPOA is assumed to expire in 2027 without renewal and the EcoEléctrica PPOA is assumed to be renewed in 2022 with modifications on the contract to prevent the immediate retirement of the plan. These modifications basically include a reduction of the fixed payments to 55% (new 2022 payment \$108 million down from 240 million the prior year) and EcoEléctrica being able to cycle in and out of service as required to integrate renewable. On the other hand, after expiration of the existing contract the energy payments are assumed to follow market conditions, instead of the reduced prices now in place. Note that with the payment EcoEléctrica was still found to be retired over the medium term due to the entry of

an F-Class CCGT. Hence for the ESM plan that does not consider this option, the payment was reduced to 60% (new 2022 payment \$88 million down from 240 million the prior year).

4. Energy Efficiency is assumed to meet the requirement of the IRP Regulation of 2% per year incremental savings attributable to new energy efficiency programs.
5. Peaking generation was added to all LTCEs under Strategy 2 and Strategy 3 ensure that the critical loads located in each of the recommended eight electric islands into which the system would be segregated after a major storm (the MiniGrids), could be served on grid isolated mode. This peaking generation along with the renewable generation and the storage in the MiniGrid would serve the priority loads and as much as possible of the balance of the load. Strategy 1 did not have this requirement and was used to identify the tradeoff between benefits and costs (value of loss load) of relying on central generation. The ESM had also these GT's as a fixed decision.

It should be noted that the possibility of achieving permitting approval for any of the LNG terminal above does not mean that the option of gas generation was automatically be selected nor its size.

5.5 Sensitivities

Sensitivity analyses were used to isolate the impacts of certain important variables while holding other assumptions constant. For the 2018 IRP, six sensitivities were included in the core scope of this study²⁶, as shown in Exhibit 5-3. PREPA IRP Sensitivity Definition and further described below

- Sensitivity 1:** Deeper reduction in cost of solar and storage, coupled with high availability of storage and solar. In Sensitivity 1, higher yearly limits of PV/BESS (photovoltaic / battery energy storage system) are assumed. See Exhibit 6-27 for the limits of this Sensitivity 1. As a reference, Exhibit 6-28 has the limits for the core LTCE and Exhibit 6-29 the limits for the ESM.
- Sensitivity 2:** Lower energy efficiency penetration (~1% reduction per year instead of 2%).
- Sensitivity 3:** Economic retirement of AES and EcoEléctrica regardless of contract term. In practice, if AES is not forced to retire, it will not retire, and as indicated earlier EcoEléctrica's contract needs to be modified.
- Sensitivity 4:** Ship-based LNG at San Juan could achieve permitting approval. The ship-based LNG at San Juan can basically supply the conversion of San Juan 5&6 and provide limited gas to other developments. It has reduced capacity in comparison to the land-based LNG option.
- Sensitivity 5:** High gas prices.
- Sensitivity 6:** High cost of solar and storage.

²⁶ Once this study is completed, more sensitivities models and stochastic analysis could be run as well as running the core sensitivities on other strategies, as required by the PREB.

Exhibit 5-3. PREPA IRP Sensitivity Definition

Sensitivity	Solar/BESS	Energy Efficiency	PPOAs	Gas		Solar/BESS
	Low Cost	Low EE	Economic Retirement of AES and EcoEléctrica	Ship-based LNG at San Juan	High Gas Prices	High Cost
1	◆					
2		◆				
3			◆			
4				◆		
5					◆	
6						◆

Additional important sensitivities were proposed by stakeholders, including no RPS (renewable portfolio standard – Act 82-2010) and/or postponed MATS compliance (US EPA Mercury and Air Toxics Standards regulation) to show the cost of compliance. However, all LTCE plans and the ESM exceeded the RPS limits (in some cases widely). Also, most MATS noncompliant units were retired on economics rather than compliance reasons, which forced the units to retire by 2025.

Finally, it is recognized that additional sensitivities could be included as gas to the north and south via pipelines, emissions prices (CO₂), and cost of capital.

5.6 Portfolio Cases

Portfolio cases are unique combinations of Scenarios and strategies. Exhibit 5-4 below illustrates the 32 portfolio cases to be modeled in the core IRP. The portfolio cases are named under the convention of “Scenario ID + Strategy ID + Sensitivity ID + Load Forecast (High, Base or Low)”.

It can be noted below that for Scenarios 1 to 4 and certain sensitivities, the portfolio cases and the resulting LTCE plan is assessed for the High, Base, and Low load growth forecast. Strategy 2 and Strategy 3 are considered for the Scenarios 1 to 4 and as Scenario 5 is designed not to have any restrictions, the Strategy 1 is used. Strategy 3 is used for most of the sensitivities.

Regarding the 32 portfolio cases and associated model treatment, the LTCE is run in all portfolio cases, the detailed nodal runs are done on the Base Case, and the PSS®E assessments are done in those cases that are expected to result in maximum stresses of the system, either in terms of large amounts of renewable online or heavier use of the transmission facilities.

In addition to the 32 portfolios below, as a result of analysis of results, two additional portfolios were developed: a) one for Scenario 2 Strategy 2 where we uniformed the peaking generation additions to avoid different technologies in the same plant providing similar products and b) a sensitivity to the ESM case where we evaluated the impact of requiring 50% renewable penetration by 2040.

Exhibit 5-4. PREPA 2018 IRP Portfolio Cases Summary

Count	Case ID	Scenario	Strategy	Sensitivity	Load	Aurora LTCE	Nodal Run	PSSE
1	S1S2B	1	2		Base	Yes	Yes	
2	S1S2H	1	2		High	Yes		
3	S1S2L	1	2		Low	Yes		
4	S1S3B	1	3		Base	Yes		
5	S1S3H	1	3		High	Yes		
6	S1S3L	1	3		Low	Yes		
7	S1S2S1B	1	2	1	Base	No		
8	S1S2S2B	1	2	2	Base	Yes		
9	S1S2S3B	1	2	3	Base	Yes		
10	S1S1B	1	1		Base	Yes		
11	S3S2B	3	2		Base	Yes		
12	S3S2H	3	2		High	Yes		
13	S3S2L	3	2		Low	Yes		
14	S3S3B	3	3		Base	Yes		
15	S3S3H	3	3		High	Yes		
16	S3S3L	3	3		Low	Yes		
17	S4S2B	4	2		Base	Yes	Yes	Yes
18	S4S2H	4	2		High	Yes		
19	S4S2L	4	2		Low	Yes		
20	S4S3B	4	3		Base	Yes		
21	S4S3H	4	3		High	Yes		
22	S4S3L	4	3		Low	Yes		
23	S4S2S3B	4	2	3	Base	Yes		
24	S4S2S4B	4	2	4	Base	Yes		
25	S4S2S5B	4	2	5	Base	Yes		
26	S4S2S6B	4	2	6	Base	Yes	Yes	
27	S4S1B	4	1		Base	Yes		no
28	S5S1B	5	1		Base	Yes	Yes	
29	S5S1S5B	5	1	5	Base	Yes		
30	ESM Plan	4	2		Base		Yes	Yes
31	ESM high	4	2		High			
32	ESM low	4	2		Low			

Part

6

New Resource Options

6.1 Overview of New Generation Resources

Siemens and PREPA discussed the key criteria in developing new generation resources to allow for system flexibility and reliability, including the capability to accommodate large blocks of renewable capacity, primarily solar. Siemens conducted technology screening to identify technically feasible and commercially viable generation resources that could be used as building blocks in constructing generation asset portfolios. For this reason, the technology screening focuses on resource options that could meet PREPA's new generation resource requirements, including:

1. Size of the new generation resource, which is informed by factors including size of the maximum contingency and local reserve requirements, load profile, retirement of existing resources, and expiration of PPOA, etc.
2. Resource type: base load, intermediate, intermittent, or peaking resources, largely determined by renewable generation integration.
3. Characteristics: ramping rate and daily cycling capability.
4. Fuel type: fossil-fueled (natural gas, diesel or dual fuel with natural gas as primary and diesel as backup).
5. Local considerations: altitude, temperature, natural wind or solar resources, etc.
6. The technology selection on a broader perspective considered a combination of dispatchable fossil-fueled generation resources, storage and renewable technologies.
7. Utility scale solar and storage for new builds of renewable resources.
8. Fossil-fueled resources included CCGT, GT, reciprocating internal combustion engines (RICE), and CHP. Siemens relied upon information exchanged with PREPA, performance and cost information provided by vendors, as well as GT Pro²⁷ software performance and cost calculations in estimating representative generation resources.

²⁷ GT Pro is a software program licensed by ThermoFlow for sizing and designing simple cycle, combined cycle, cogeneration, GT, CCGT, CHP, and other types of power generation units. GT Pro was used to determine, among other measures, plant output, heat rate, duct firing capacity, and capital costs for the specified site conditions and available fuels.

6.2 New Fossil-Fired Generation Resources

6.2.1 Generation Options Development and Sizing

A three-step process was used to determine generating unit characteristics and select technologies for portfolios as discussed below.

First, Siemens performed a technology screening. GTs and their corresponding CCGT plants come in discrete sizes based on equipment offerings from a limited number of worldwide manufacturers. Siemens' approach was to screen a large number of available GT and CCGT configurations from all major manufacturers like GE, Mitsubishi, Hitachi, Siemens, and Solar Turbines, based mainly on published performance of available GT and CCGT generating units at ISO conditions (59° F, 60 percent relative humidity, and sea level) with wet cooling towers on natural gas fuel. All CCGT cases were evaluated in 1 x 1 Power Block configuration, i.e., a single train of GT, Heat Recovery Steam Generator (HRSG) and Steam Turbine Generator (STG).²⁸ A limited number of cases from various manufacturers were selected for analysis in GT Pro software.

Second, from this group, certain configurations were selected for modeling in GT Pro to obtain performance specific to PREPA site conditions (85° F, 70 percent relative humidity, and 25 or 1,000 feet above mean sea level²⁹) on natural gas and distillate oil (also known as Diesel or Light Fuel Oil - LFO), with and without duct firing, and with dry cooling as appropriate for the application. New CCGTs assumed dry cooling with Air Cooled Condensers (ACCs). Siemens criterion was to design and size the plant based on liquid (distillate or diesel) fuel, then to determine corresponding performance of the same design operating on natural gas. It should be noted that this likely resulted in somewhat less attractive performance than for a plant designed solely for natural gas fuel. Future optimization is possible for Scenarios using CCGT with natural gas as primary fuel.

Finally, GT Pro performance estimates were used to select which configurations to consider in developing the generation portfolios for capacity expansion in AURORA and the subsequent nodal analysis in AURORA-Nodal.

When Siemens selected new generation options for inclusion in portfolios, a particular unit design based on an actual product is chosen as representative of a class of similar units. In all cases, there is at least one additional unit available from a different manufacturer with sufficiently similar characteristics that competitive bidding would be possible at the time a project is implemented. The important point is that the generating units used for the IRP purposes do not lock PREPA into any particular manufacturer for project implementation and further optimization can be achieved at the time of implementation.

For the RICE case, Siemens obtained published Wartsila performance information for a large engine capable of dual fuel (natural gas and diesel) operation. Siemens made a manual adjustment for site conditions. This engine requires about 0.5 to 1.0 percent diesel pilot fuel when operating on natural

²⁸ 1 x 1 Power Block projects give siting flexibility in modeling. If multiple trains are needed in same location, later optimizations can be performed to evaluate whether 2 x 1 or 3 x 1 fit the operating profile and are more economic than 1 x 1.

²⁹ Large plants near coast were set at 25 ft AMSL to be above storm surge. Smaller plants that might be used at interior sites were set at 1,000 ft AMSL.

gas. Siemens made a small adjustment to the RICE natural gas heat rate to account for the higher cost of the pilot fuel.

All selected generation resources are analyzed based on dual fuel capability with natural gas and diesel, with gas being the primary fuel when available and an option when not. For dual fuel units, the unit output and heat rate are somewhat different depending on the fuel type. The representative options selected by Siemens are discussed in the next subsection.

6.2.2 Representative Future Generation Resources Characteristics

As indicated above, Siemens developed key operational parameters of the representative future generation resources, primarily relying on published vendor information as well as vendor-supplied performance and cost information available in GT Pro performance software.

Exhibit 6-1 presents the operational parameters for an H Class Combined Cycle (GE S107HA.01) unit. Exhibit 6-2 and Exhibit 6-3 present the operational parameters of a larger F-Class Combined Cycle (CCGT - GE S107F.05) unit and a smaller F-Class Combined Cycle (CCGT - GE S107F.04) unit, respectively. Exhibit 6-4 presents the operational parameters for medium-sized combined cycle (Hitachi H-100). These units have a short minimum run time and hence can cycle in and out of service daily. Also, the minimum capacity is 39 to 48 percent of the duct fired capacity allowing a significant reduction in output before the units must be turned off. In addition, the units can ramp up from their minimum to the maximum capacity in 3.5 to 8 minutes.

**Exhibit 6-1. H Class Combined Cycle (GE S107HA.01)
Operational Assumptions**

Generation Unit Type	Unit	H Class CC (GE S107HA.01)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	374	365
Max. Unit Capacity with Duct Fire	MW	449	438
Min. Unit Capacity	MW	176	172
Min. Unit Capacity (% of Duct F Capacity)	%	39%	39%
Fixed O&M Expense	2018 \$/kW-year	22.09	22.09
Variable O&M Expense	2018 \$/MWh	1.75	1.75
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	6.77	6.60
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	7.09	6.90
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	2.0%	2.0%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	40	40
Ramp Down Rate	MW/minute	40	40
Regulation Minimum Range	MW	176	172
Regulation Maximum Range	MW	449	438
Regulation Ramp Rate	MW/minute	40	40

Exhibit 6-2. F-Class CCGT - Larger (GE S107F.05)
Operational Assumptions

Generation Unit Type	Unit	F Class CC - Larger (GE S107F.05)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	303	295
Max. Unit Capacity with Duct Fire	MW	369	361
Min. Unit Capacity	MW	172	168
Min. Unit Capacity (% of Duct F Capacity)	%	47%	47%
Fixed O&M Expense	2018 \$/kW-year	22.09	22.09
Variable O&M Expense	2018 \$/MWh	1.75	1.75
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	7.25	7.07
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	7.53	7.32
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	40	40
Ramp Down Rate	MW/minute	40	40
Regulation Minimum Range	MW	172	168
Regulation Maximum Range	MW	369	361
Regulation Ramp Rate	MW/minute	40	40

Exhibit 6-3. F-Class CCGT - Smaller (GE S107F.04)
Operational Assumptions

Generation Unit Type	Unit	F Class CC - Smaller (GE S107F.04)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	251	245
Max. Unit Capacity with Duct Fire	MW	302	296
Min. Unit Capacity	MW	144	141
Min. Unit Capacity (% of Duct Fired Capacity)	%	48%	48%
Fixed O&M Expense	2018 \$/kW-year	22.09	22.09
Variable O&M Expense	2018 \$/MWh	1.75	1.75
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	7.27	7.09
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	7.55	7.34
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	144	141
Regulation Maximum Range	MW	251	245
Regulation Ramp Rate	MW/minute	30	30

Exhibit 6-4. Medium CCGT Hitachi (H-100) Operational Assumptions

Generation Unit Type	Unit	Medium CC (Hitachi H-100)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	116	113
Max. Unit Capacity with Duct Fire	MW	144	141
Min. Unit Capacity	MW	61	60
Min. Unit Capacity (% of Duct F Capacity)	%	42%	42%
Fixed O&M Expense	2018 \$/kW-year	33.12	33.12
Variable O&M Expense	2018 \$/MWh	2.61	2.61
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	7.76	7.56
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	8.25	8.02
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	15	15
Ramp Down Rate	MW/minute	15	15
Regulation Minimum Range	MW	61	60
Regulation Maximum Range	MW	144	141
Regulation Ramp Rate	MW/minute	15	15

Exhibit 6-5, Exhibit 6-6 and Exhibit 6-7 present the operational parameters of the small combined cycle units (GE LM6000 DLE, GE LM2500+G4 SAC, and GE LM2500 SAC) considered in the IRP. As with the larger units, these units have a short minimum run time and can cycle in and out of service daily. Their minimum capacity is 42 to 51 percent of the duct fired capacity, allowing a significant reduction in output before the units must be turned off. These units can ramp up from their minimum to the maximum normal capacity in about 30 seconds. The GE LM2500+G4 SAC was modeled with the capability of burning LPG and natural gas when offered as an option for the North and in the ESM, plan as discussed later in this report.

**Exhibit 6-5. Small CCGT (GE LM6000 DLE) (Duct Fired)
Operational Assumptions**

Generation Unit Type	Unit	Small CC (GE LM6000 DLE)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	51	49
Max. Unit Capacity with Duct Fire	MW	66	63
Min. Unit Capacity	MW	27	26
Min. Unit Capacity (% of Duct F Capacity)	%	42%	42%
Fixed O&M Expense	2018 \$/kW-year	36.13	36.13
Variable O&M Expense	2018 \$/MWh	5.29	5.29
Heat Rate at 100% Rated Capacity	MMBtu/MWh	7.83	7.65
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	8.62	8.37
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	50	50
Ramp Down Rate	MW/minute	50	50
Regulation Minimum Range	MW	27	26
Regulation Maximum Range	MW	66	63
Regulation Ramp Rate	MW/minute	50	50

Source: Siemens

**Exhibit 6-6. Small CCGT (GE LM2500 +G4 SAC)
Operational Assumptions**

Generation Unit Type	Unit	Small CC (GE LM2500+ G4 SAC)	
		Natural Gas	Diesel
Max. Unit Capacity	MW	38	38
Min. Unit Capacity	MW	19	20
Min. Unit Capacity (% of max Capacity)	%	51%	51%
Fixed O&M Expense	2018 \$/kW-year	41.33	41.33
Variable O&M Expense	2018 \$/MWh	3.12	3.12
Heat Rate at 100% Rated Capacity	MMBtu/MWh	8.34	8.08
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	19	20
Regulation Maximum Range	MW	38	38
Regulation Ramp Rate	MW/minute	30	30

Exhibit 6-7. Small CCGT (GE LM2500 SAC) Operational Assumptions

Generation Unit Type	Unit	Small CC (GE LM2500 SAC)	
		Natural Gas	Diesel
Max. Unit Capacity	MW	29	28
Min. Unit Capacity	MW	15	14
Min. Unit Capacity (% of max Capacity)	%	51%	51%
Fixed O&M Expense	2018 \$/kW-year	42.49	42.49
Variable O&M Expense	2018 \$/MWh	3.12	3.12
Heat Rate at 100% Rated Capacity	MMBtu/MWh	8.69	8.46
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	15	14
Regulation Maximum Range	MW	29	28
Regulation Ramp Rate	MW/minute	30	30

Exhibit 6-8, Exhibit 6-9 and Exhibit 6-10 present the operational parameters of the GT units (Mobile, GE LM6000 DLE, and GE LM2500 SAC) considered in the IRP, which can cycle in and out of service frequently. The units in Exhibit 6-8 are mobile units and are good candidates for replacement of the existing Frame 5 units (21 MW each).

These GT's typically have a minimum capacity of 50% of the maximum (due to emissions limitations) and can ramp up from minimum to maximum capacity in less than 25 seconds.

Exhibit 6-8. Simple Cycle Mobile Unit

Generation Unit Type	Unit	FT8 MOBILEPAC 25 DLN	
		Natural Gas	Diesel
Max. Unit Capacity	MW	23.2	22.6
Min. Unit Capacity	MW	11.9	11.3
Fixed O&M Expense	2018 \$/kW-year	38.62	38.62
Variable O&M Expense	2018 \$/MWh	3.12	3.12
Heat Rate at 100% Rated Capacity	MMBtu/MWh	11.12	10.96
Unit Capacity Degradation	%	2.50%	2.50%
Unit Heat Rate Degradation	%	1.50%	1.50%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	11.9	11.3
Regulation Maximum Range	MW	23.8	22.6
Regulation Ramp Rate	MW/minute	30	30

**Exhibit 6-9. Simple Cycle Peaker GT (GE LM6000 DLE)
Operational Assumptions**

Generation Unit Type	Unit	SC Peaker (GE LM6000 DLE)	
		Natural Gas	Diesel
Max. Unit Capacity	MW	41	39
Min. Unit Capacity	MW	21	19
Min. Unit Capacity (% of Max Capacity)	%	50%	50%
Fixed O&M Expense	2018 \$/kW-year	32.85	32.85
Variable O&M Expense	2018 \$/MWh	5.29	5.29
Heat Rate at 100% Rated Capacity	MMBtu/MWh	9.83	9.68
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	0.02	0.02
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	50	50
Ramp Down Rate	MW/minute	50	50
Regulation Minimum Range	MW	21	19
Regulation Maximum Range	MW	41	39
Regulation Ramp Rate	MW/minute	50	50

**Exhibit 6-10. Simple Cycle Peaker GT (GE LM2500 SAC)
Operational Assumptions**

Generation Unit Type	Unit	SC Peaker (GE LM2500 SAC)	
		Natural Gas	Diesel
Max. Unit Capacity	MW	22	21
Min. Unit Capacity	MW	11	11
Min. Unit Capacity (% of Max Capacity)	%	50%	50%
Fixed O&M Expense	2018 \$/kW-year	38.63	38.63
Variable O&M Expense	2018 \$/MWh	3.12	3.12
Heat Rate at 100% Rated Capacity	MMBtu/MWh	11.49	11.14
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	0.02	0.02
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	11	11
Regulation Maximum Range	MW	22	21
Regulation Ramp Rate	MW/minute	30	30

Source: Siemens

Exhibit 6-11 presents the operational parameters for the RICE technologies, which are very flexible, able to cycle frequently, and have low minimum loading and very fast loading rates.

Exhibit 6-11. Reciprocating Engine Operational Assumptions

Generation Unit Type	Unit	Reciprocating Engine	
		Natural Gas	Diesel
Max. Unit Capacity	MW	16	16
Min. Unit Capacity	MW	2	2
Min. Unit Capacity (% of Max Capacity)	%	10%	10%
Fixed O&M Expense	2018 \$/kW-year	28.98	28.98
Variable O&M Expense	2018 \$/MWh	10.33	10.33
Heat Rate at 100% Rated Capacity	MMBtu/MWh	8.53	8.89
Unit Capacity Degradation	%	1.0%	1.0%
Unit Heat Rate Degradation	%	0.5%	0.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	0.02	0.02
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	2.5	2.5
Ramp Down Rate	MW/minute	2.5	2.5
Regulation Minimum Range	MW	5	5
Regulation Maximum Range	MW	16	16
Regulation Ramp Rate	MW/minute	2.5	2.5

Source: Siemens

As discussed, these selections are representative of each particular technology class and do not represent final recommendations of particular equipment or manufacturer. Exact sizing, configuration and performance should be optimized when an actual generation project is planned and implemented. But for planning purposes, these units demonstrate how different representative technologies would fit in the overall dispatch analysis. Output and heat rate degradation are applied as a single adjustment to the “New and Clean” performance to represent annual average performance over the generating unit’s operating life.

Combined Heat and Power (CHP) was also considered as an option and this is discussed in Appendix 4: Demand-Side Resources.

6.2.2.1 Existing Fleet Considerations

In this IRP, no repowering of existing units is considered due to the complications associated with trying to “recycle” aged infrastructure. However, the fuel conversion of San Juan 5&6 was considered as a committed decision and there is the possibility of fuel conversions of the Aguirre CCGT. For the fuel conversion candidates, the capital costs assumptions are presented in Exhibit 6-12.

Exhibit 6-12. Fuel Conversion Projects Capital Costs Assumptions

Dual Fuel Conversion Projects	Capital Costs (thousand 2018\$)
Aguirre 1 CCGT Dual Fuel Conversion	25,371
Aguirre 2 CCGT Dual Fuel Conversion	25,371

Source: Siemens

6.2.2.2 Representative Future Generation Resources Capital Costs

Capital costs for the representative future generation resources are key parameters in the IRP models. Siemens developed the capital costs assumptions using the PEACE capital cost estimating module associated with GT Pro software. PEACE uses equipment selection and sizing as determined in GT Pro to estimate equipment and installation costs, including associated costs such as foundations, piping, wiring, buildings, etc. Other components including contractor engineering, commissioning, overhead, escalation, contingency and fees are added to determine the Engineering, Procurement and Construction (EPC) price. Owner's costs for development, permitting and legal/contracting activities, and cost escalation were included in PEACE. Most power projects implemented by private developers on a project non-recourse financing basis, incur total development and financing costs, including Interest during Construction, financing fees, project management, O&M mobilization, startup fuels and consumables, etc. PEACE included 9 percent of EPC for development costs. Also, PEACE includes certain adjustments to labor productivity and labor and materials costs based on project location. However, the program does not include adjustments specific to Puerto Rico costs. Siemens adopted the U.S. Department of Defense Area Cost Factor of 16 percent for Puerto Rico. This adjustment was inserted into PEACE as a user input and it was applied against equipment, material and labor costs to reflect delivery or local purchase and installation of equipment and materials for the project.

PEACE cost estimates are not as accurate as obtaining project specific equipment and construction costs estimates from suppliers and contractors but are suitable for planning purposes and provide a consistent approach across all generation resource options. The PEACE cost estimates also reflect the specific configuration and sizing of options, such as duct firing and Air-Cooled Condensers, which need to be considered when factoring costs based on other projects whose configurations may vary. Exhibit 6-13 shows the estimated all-in capital costs for the selected representative technologies.

Exhibit 6-13. New Generation Resources Capital Costs

Representative New Resource Candidates	Natural Gas Fired		Diesel Fired	
	Capacity (MW)	Capital Costs (2018\$/KW)	Capacity (MW)	Capital Costs (2018\$/KW)
H Class CCGT (GE S107HA.01)	449	\$899	438	\$921
F-Class CCGT (GE S107F.04) (Duct Fired)	302	\$994	296	\$1,017
F-Class CCGT (GE S107F.05) (Duct Fired)	369	\$927	361	\$948
Medium CCGT (Hitachi H-100) (Duct Fired)	144	\$1,250	141	\$1,275
Small CCGT (GE LM6000 DLE) (Duct Fired)	66	\$1,658	63	\$1,729
Small CCGT (GE LM2500+ G4 SAC) (Duct Fired)	38	\$1,798	38	\$1,812
Small CCGT (GE LM2500 SAC) (Duct Fired)	29	\$2,010	28	\$2,052
Aero/Small GT Peaker (GE LM6000 DLE)	41	\$1,375	39	\$1,444
Aero/Small GT Peaker (GE LM2500 SAC)	22	\$1,627	21	\$1,689
Small CHP (Solar Turbines Mars 100)	9	\$2,651	9	\$2,639
RICE (Wartsila 18V50DF)	16	\$1,612	16	\$1,612

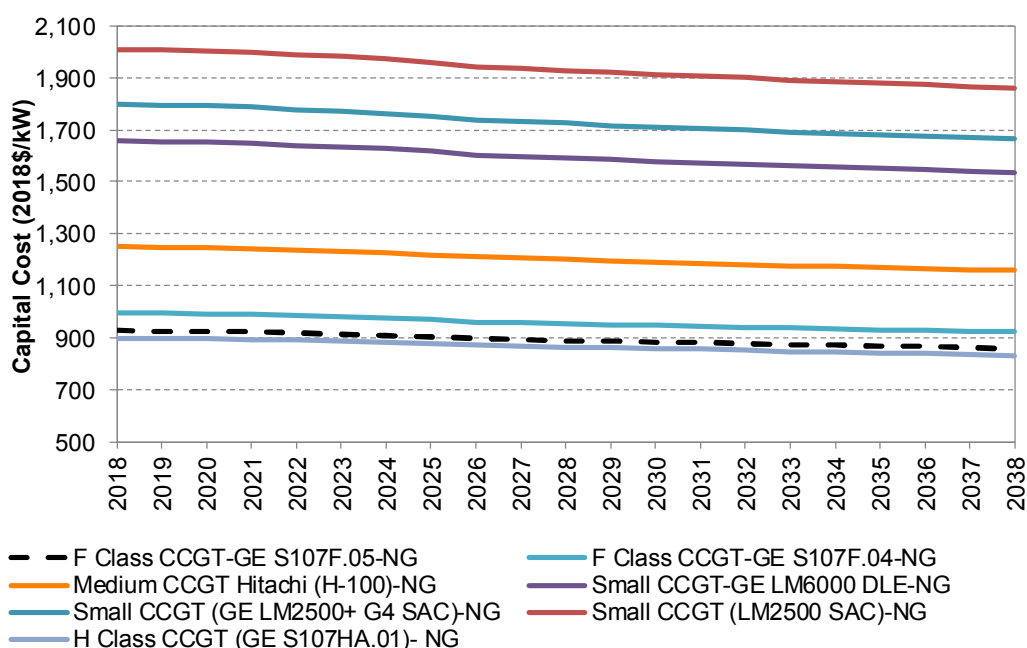
Source: Siemens

For the replacement of the 21 MW Frame 5 units using the mobile units (FT8 MOBILEPAC 25 DLN) presented earlier, there are capital cost differences whether it is replacing an existing unit or adding another unit on site. This is presented below.

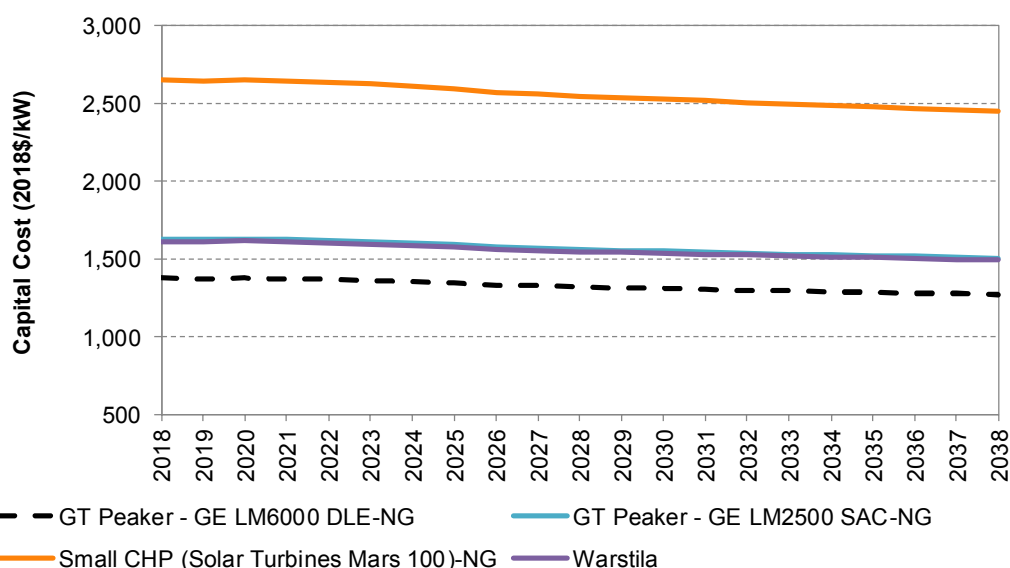
Exhibit 6-14. New Generation Resources Capital Costs

Name	Existing Units	Zone	Capex (\$/kW) Existing	Capex (\$/kW) Additional
Daguao	2	Carolina	900	1000
Yabucoa	2	Caguas	900	1000
Palo Seco	6	Bayamon	900	1000
Costa Sur	2	Ponce Oe	900	1000
Aguirre	2	Ponce ES	900	1000
Vega Baja	2	Bayamon	900	1000
Jobos	2		900	1000

The capital cost curves below are derived based of the 2018 National Renewable Energy Laboratory (NREL) Annual Technology Baseline for the Gas CC/CT based on Annual Energy Outlook 2018. The costs curves can be used to estimate the capital costs for future units considering the deployment dates.

Exhibit 6-15. Capital Cost Curve for Gas CCGT

Source: Siemens, NREL 2018 ATB

Exhibit 6-16. Capital Cost Curve for GT

Source: Siemens, NREL 2018 ATB

6.2.3 Future Generation Resources Development Timeline

For addition of new resources, IRPs need to factor development time from the initial RFP to the Commercial Operation Date. Exhibit 6-17 shows the expected development timeframes for the representative technologies. In this exhibit, development includes the activities from RFP and bid evaluation to permitting and financing. The EPC is the actual engineering, procurement and construction to Commercial Operation.

Exhibit 6-17. Development and Construction Durations

Representative New Resource Candidates	Capacity (MW)	Development Duration (Years)	EPC Duration (Years)
H Class CCGT (GE S107HA.01) (Duct Fired)	449	2.5	3.0
F-Class CCGT (GE S107F.04) (Duct Fired)	302	2.5	3.0
F-Class CCGT (GE S107F.05) (Duct Fired)	369	2.5	3.0
Medium CCGT (Hitachi H-100) (Duct Fired)	144	2.5	2.5
Small CCGT (GE LM6000 DLE) (Duct Fired)	66	2.0	2.0
Small CCGT (GE LM2500+ G4 SAC) (Duct Fired)	47.7	2.0	2.0

Representative New Resource Candidates	Capacity (MW)	Development Duration (Years)	EPC Duration (Years)
Small CCGT (GE LM2500 SAC) (Duct Fired)	35	2.0	2.0
Aero/Small GT Peaker (GE LM6000 DLE)	41	1.5	1.5
Aero/Small GT Peaker (GE LM2500 SAC)	22	1.5	1.5
Small CHP (Solar Turbines Mars 100)	9	1.5	1.5
RICE (Wartsila 18V50DF)	16	1.5	1.5

Note: Capacity based on natural gas firing.

6.2.4 Levelized Cost of Energy (LCOE)

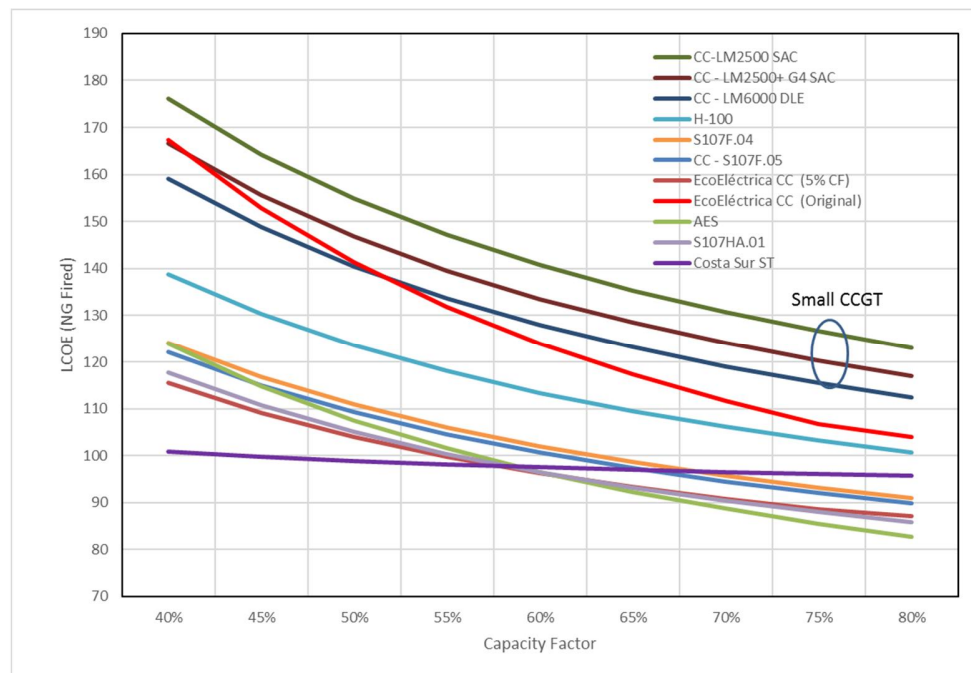
A high level LCOE was calculated on all new technologies to form a preliminary view of their respective costs for the IRP.

The LCOE was estimated using the heat rate at 100% rated unfired capacity and considering delivered diesel and new natural gas prices (including commodity, liquefaction, and shipping, but not regasification costs) at San Juan to calculate fuel costs. The regasification costs were determined considering a land-based LNG regasification terminal at San Juan with a pipeline to Palo Seco with max daily gas volume of 93.6 MMcf/day to support a total generation capacity of 650 MW. Siemens estimated that this regasification infrastructure adds a fixed cost of \$116.5/kW-year to any potential new gas-fired generation resources at San Juan or Palo Seco accounting for fixed operating costs and return on capital at a WACC (weighted average cost of capital) of 8.5 percent and an economic life of 22 years. This same WACC was used to annualize the generation capital considering an asset economic life of 29 years for a large combined cycle plant and 20 years for the remaining technologies.

As a reference, Siemens also calculated the LCOE for Costa Sur 5 & 6 considering the O&M costs plus delivered gas. For AES, Siemens considered the forecasted cost of coal, O&M and capacity payments. For EcoEléctrica, Siemens considered the two fuel components reflected in the PPOA; for energy under 76% dispatch, and for the spot price energy produced above that level it was assumed to be equal to the delivered gas at San Juan. Siemens also factored in the EcoEléctrica O&M costs and capacity payments.

Exhibit 6-18 shows the LCOE of the large and medium CCGT with gas and a comparison with the estimated LCOE of Costa Sur 5&6, EcoEléctrica and AES. Exhibit 6-19 provides the numeric values of this LCOE. As can be observed below, depending on the dispatch (and the fuel price assumptions made), it is possible that EcoEléctrica could be economically retired as well as Costa Sur 5&6, considering that its replacement by a flexible CCGT will reduce the need for energy storage capacity. This result would change for the case where the EcoEléctrica contract is renegotiated, and the capacity payments are reduced.

Exhibit 6-18. Large and Medium CCGT with Gas, Costa Sur 5&6, EcoEléctrica and AES



Source: Siemens

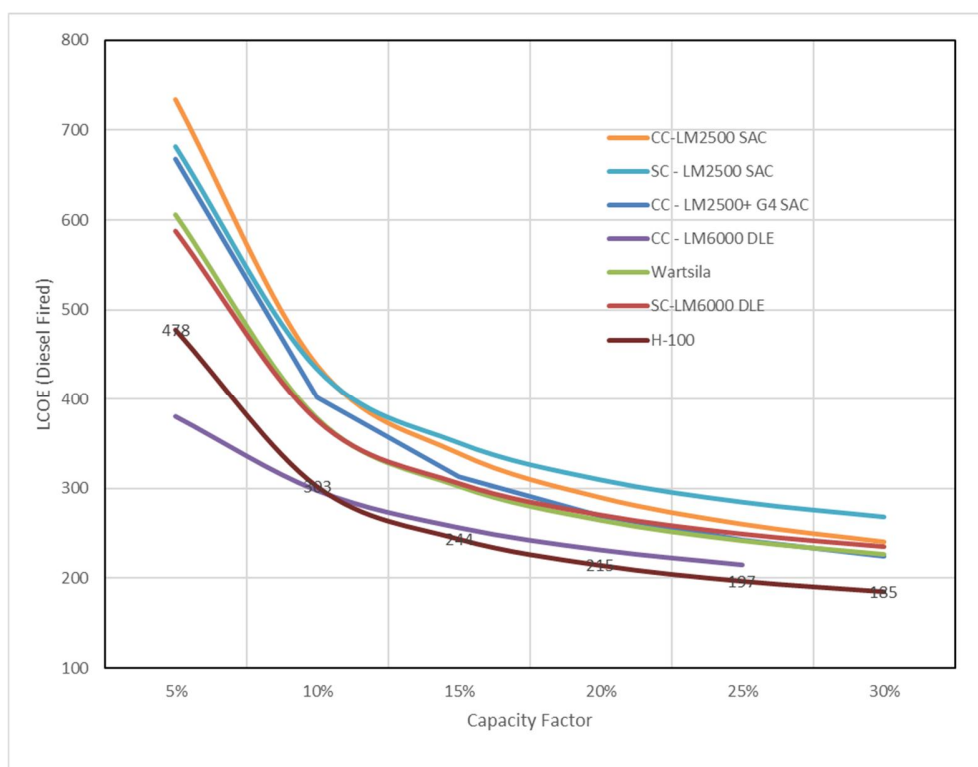
Exhibit 6-19. LCOE for Large and Medium Combined Cycle units

Case Description	H Class CCGT		F Class CCGT		F Class CCGT		Medium CCGT	
Manufacturer	GE		GE		GE		MHPS	
Model	S107HA.01		CC - S107F.05		S107F.04		H-100	
Type	CC 1x1		CC 1x1		CC 1x1		CC 1x1	
Capacity MW	449	438	369	361	302	296	144	141
Fuel	NG	Diesel	NG	Diesel	NG	Diese	NG	Diesel
Capacity Factor	LCOE (2018\$/MWh)							
5%	565	360	574	373	589	388	674	478
10%	309	235	316	246	323	253	368	303
15%	224	193	230	203	235	208	266	244
20%	182	173	187	182	191	186	215	215
25%	156	160	161	169	164	172	185	197
30%	139	152	144	161	146	163	164	185
35%	127	146	131	154	134	157	150	177
40%	118	141	122	150	124	152	139	171
45%	111	138	115	146	117	148	130	166
50%	105	135	109	144	111	145	124	162
55%	100	133	105	141	106	143	118	159
60%	96	131	101	139	102	141	113	156
65%	93	129	97	138	99	139	109	154
70%	90	128	94	136	96	138	106	152
75%	88	127	92	135	93	136	103	150
80%	86	126	90	134	91	135	101	149
85%	84	125	88	133	89	134	98	148
90%	82	124	86	132	87	133	96	146

Source: Siemens

With respect of the small CCGT units, GT and the Wärtsilä RICE, Exhibit 6-20 below shows the LCOE cost converge near the expected capacity factor ranges, with perhaps the LM2500 being the least competitive. The LCOE is presented considering Diesel (LFO) as the likely fuel for these units. Exhibit 6-21 show the numeric values for the LCOE for the small CCGT units and Exhibit 6-22 for the CHP option. Siemens further notes in this exhibit that for applications where large amount of power are required, the H-100 Combined Cycle and the LM6000 Combined Cycle are competitive even at very small capacity factors.

Exhibit 6-20. Small CCGT, Peakers (GT) and RICE with Diesel



Source: Siemens

**Exhibit 6-21. LCOE for Small Combined Cycle units and
GT Aero Peakers**

Case Description	Aero or Small CCGT		Aero or Small CCGT		Aero or Small CCGT		Aero SC/ Peaker		Aero SC/ Peaker	
Manufacturer	GE		GE		GE		GE		GE	
Model	CC - LM6000 DLE		CC - LM2500+ G4 SAC		CC-LM2500 SAC		SC-LM6000 DLE		SC - LM2500 SAC	
Type	CC 1x1		CC 1x1		CC 1x1		SC		SC	
	x'	63	38	38	29	28	41	39	22	21
Fuel	NG	Diesel	NG	Diesel	NG	Diesel	NG	Diesel	NG	Diesel
Capacity Factor	LCOE (2018\$/MWh)									
5%	814	631	861	667	918	734	754	588	838	682
10%	440	381	464	402	494	438	417	376	465	434
15%	315	298	332	313	353	340	305	306	340	351
20%	253	256	266	269	282	290	249	270	278	310
25%	215	231	226	242	240	261	215	249	241	285
30%	190	214	200	225	211	241	193	235	216	269
35%	173	202	181	212	191	227	177	225	198	257
40%	159	194	167	202	176	216	165	217	185	248
45%	149	187	156	195	164	208	156	211	175	241
50%	140	181	147	189	155	201	148	207	166	236
55%	134	177	140	184	147	196	142	203	159	231
60%	128	173	134	180	141	192	137	200	154	228
65%	123	170	128	177	135	188	133	197	149	224
70%	119	167	124	174	131	184	129	195	145	222
75%	115	164	120	171	127	182	126	193	141	219
80%	112	162	117	169	123	179	123	191	138	217
85%	110	160	114	167	120	177	121	189	135	215
90%	107	159	111	166	117	175	118	188	133	214

Source: Siemens

Exhibit 6-22. LCOE for CHP and RICE Units

Case Description	CHP		CHP (56% Heat Rate)		RICE
Manufacturer	Solar Turbines		Solar Turbines		Wartsila
Model	Mars 100		Mars 100		Wartsila 18V50DF
Type	Cogen -- LP steam		Cogen -- LP steam		
Capacity MW	9	9	9	9	16
Fuel	NG	Diesel	NG	Diesel	Diesel
Capacity	LCOE (2018\$/MWh)				
5%	1124	962	1076	867	606
10%	614	587	566	491	378
15%	444	461	396	366	302
20%	359	399	311	304	264
25%	308	361	260	266	242
30%	274	336	226	241	226
35%	250	318	202	223	216
40%	232	305	183	210	207
45%	217	294	169	199	201
50%	206	286	158	191	196
55%	197	279	149	184	192
60%	189	274	141	178	188
65%	183	269	134	174	185
70%	177	265	129	169	183
75%	172	261	124	166	181
80%	168	258	120	163	179
85%	164	255	116	160	177
90%	161	253	113	158	176

Source: Siemens

6.3 Solar Photovoltaic (PV) Projects

The IRP assumes utility scale solar for new builds of renewable resources. The cost estimates for utility scale solar PV projects are developed through the following steps: 1) establish baseline solar PV operating and overnight capital costs estimate; 2) evaluate interconnection and land costs specific to Puerto Rico; 3) assess construction and financing costs reflecting Puerto Rico specific assumptions; and 4) calculate Levelized Cost of Energy (LCOE) for solar PV in Puerto Rico.

6.3.1 Baseline Operating and Overnight Capital Costs

For step 1, the IRP assumes overnight capital costs and operating costs for utility-scale PV systems consistent with the recently published 2018 Annual Technology Baseline (ATB) by National Renewable Energy Laboratory (NREL) as shown in Exhibit 6-23. The PV system is representative of one-axis tracking systems with performance and pricing characteristics; this cost is somewhat higher than the cost of fixed tilt normally used in Puerto Rico, but it was maintained considering that in the territory additional costs may be incurred for hardening. The assumptions below do not account for a

1.3 DC-to-AC ratio, otherwise known as inverter loading ratio that is included when calculating the LCOE.

Exhibit 6-23. U.S. Utility Scale Solar PV Costs Assumptions

NREL 2018 Annual Technology Baseline (ATB) Mid Case			NREL 2018 Annual Technology Baseline (ATB) Low Case		
Year	PV Overnight Capital Costs \$2018/KWdc	Costs \$2018/kW-year (dc)	Year	PV Overnight Capital Costs \$2018/KWdc	Costs \$2018/kW-year (dc)
2018	1,087	9.52	2018	960	8.51
2019	1,046	9.11	2019	912	8.04
2020	984	8.37	2020	870	7.45
2021	933	7.80	2021	833	7.00
2022	923	7.71	2022	810	6.81
2023	912	7.63	2023	786	6.62
2024	902	7.54	2024	763	6.43
2025	891	7.46	2025	739	6.24
2026	880	7.38	2026	715	6.05
2027	870	7.29	2027	692	5.87
2028	859	7.21	2028	668	5.68
2029	849	7.12	2029	645	5.49
2030	838	7.04	2030	621	5.30
2031	831	6.98	2031	611	5.22
2032	824	6.92	2032	600	5.13
2033	817	6.86	2033	590	5.05
2034	809	6.81	2034	582	4.98
2035	802	6.75	2035	565	4.85
2036	795	6.69	2036	552	4.74
2037	788	6.63	2037	538	4.64
2038	780	6.57	2038	525	4.53
2039	773	6.52	2039	512	4.43

Source: NREL 2018 ATB, converted to \$2018. (<https://atb.nrel.gov/electricity/data.html>)

6.3.2 Interconnection Costs

The NREL benchmark includes the transformation to transmission voltage level (e.g. 115 kV) and a cost of \$0.03/Wdc³⁰ for interconnection costs to the point of interconnection (POI) and a cost of \$263,000 for the interconnecting lines (Gen-Ties) to the POI (based on a 30 MW plant). In the case of PREPA, these costs can change significantly, thus Siemens added the PREPA specific cost to its estimate and subtracted the corresponding NREL cost element. Exhibit 6-24 shows the interconnection costs assumed for a solar PV project that includes the expansion of an existing substation with one new bay for the solar PV project, the expansion of the control house, and 1 mile of interconnecting line. All unit costs shown were provided by PREPA.

Exhibit 6-24. Interconnection Costs

Interconnection Costs	Unit	Value	Unit Price \$/unit	Capital (\$ 000)
Interconnecting Line (Gen-Tie)	Miles	1	1,500,000	1,500
Right of Way Costs (115 kV 50 ft wide)	m2	24,521	3	74
New Bay for Interconnection	Each	1	2,400,000	2,400
Control House Extension	Each	1	300,000	300
Total Interconnection Cost				4,274
Cost already included in NREL				(1,433)
Total Adjusted Interconnection Cost				2,840

Note: The NREL interconnection costs are subject to update upon receiving response from the NREL

³⁰ The NREL interconnection costs are subject to update upon receiving response from the NREL

6.3.3 Land Costs

PV facilities require large stretches of land. NREL on its report “Land-Use Requirements for Solar Power Plants in the United States” indicates that for large projects (greater than 20 MW) the land use is approximately 7.5 acres per MWac for fixed tilt systems and approximately 8.3 acres per MWac for one-axis tilt systems. These values are in the mid-range of project values ranging from 9 acres per MWac to 5 acres per MWac, based on Siemens projects experience.

Using NREL values, a 30 MW³¹ project would require an area of 225 acres or 910,543 m². Using the land cost provided by PREPA the table below shows Siemens estimation of costs for a 30 MW project. Note that in this table, Siemens is subtracting the costs already included in NREL benchmark (\$0.03/Wdc).

Exhibit 6-25. Land Costs

Land Costs (30 MW Solar)	Unit	Value	Unit Price \$/unit	Capital (\$ 000)
Area for PV Project	m2	910,543	3	2,732
Cost already included in NREL				1,170
Total land cost				1,562

6.3.4 Weighted Average Cost of Capital (WACC)

In the context of developing a consensus assumption of WACC among key stakeholders, Siemens acknowledges a few important factors impacting both the cost and availability of capital. With \$9 billion debt outstanding, PREPA currently has no access to bond market and bank financing. In addition, recent Act 120-2018 authorized PREPA to sell its generating assets to potential private buyers.

Based on discussions with stakeholders, Siemens considers future builds to be financed by third parties and consider that PREPA obtain financial backing to contract as a credit-worthy counterparty, if and as needed. Exhibit 6-26 shows the component assumptions deriving a nominal weighted average cost of capital of 8.50%.

³¹ 30 MW was selected as a representative size of a utility scale project.

Exhibit 6-26. Weighted Average Cost of Capital Assumptions

Cost of Equity	
Asset Beta	0.70
Income Tax Rate	39.00%
Debt to Equity Ratio	0.90
Equity Beta	1.08
Risk-Free Rate	2.95%
Equity Risk Premium	5.50%
Company Specific Risk Premium	4.00%
Cost of Equity	12.91%
Cost of Debt	
Cost of Debt, Pre-tax	5.00%
Tax Rate	32.0%
Cost of Debt, After-tax	3.40%
Weighted Average Cost of Capital	
After-tax Cost of Debt	3.40%
Percent Debt	47%
Cost of Equity	12.91%
Percent Equity	53%
WACC	8.50%

Note: The corporate income tax rate is assumed based on a base rate of 20%, plus a graduated surcharge ranging from 5% to 19%³².

6.3.5 Investment Tax Credit (ITC)

The solar Investment Tax Credit (ITC) is one of the most important federal policy mechanisms to support the deployment of solar energy in the United States. Consistent with the current policy, the IRP assumes the following: solar facilities that commence construction prior to January 1, 2020 will qualify for the full amount of the ITC (i.e., 30 percent); solar facilities that commence construction during 2020, the amount of the ITC will be reduced from 30 percent to 26 percent; solar facilities that commence construction during 2021, the amount of the ITC will be reduced from 26 percent to 22 percent; and solar facilities that commence construction in 2022 or thereafter, the amount of the ITC will drop to 10 percent.

6.3.6 Project Development and Construction Time

Based on discussions with PREPA, the IRP assumes an accelerated timeline for solar projects, assuming 12 months for the development period (request for proposal, bid evaluation, permitting, and financing) and 12 months for construction.

This time line assumes fast track permitting, proper submittal of project design for evaluation by PREPA (particularly for mathematical model evaluation, and control, protection and telecommunications design), as well as securing the land for the interconnection line and any additional land acquisition required for interconnection at PREPA's facilities that will be secured by

³² Deloitte International Tax Puerto Rico Highlights 2018

project company. Those projects that require new-build PREPA interconnection facilities (sectionalizer or transmission centers) could require longer development and construction times.

Additionally, there are limits on the amount of annual installations that can effectively be carried out in parallel. This changes as a function of the Scenarios discussed earlier and are as presented below.

Exhibit 6-27: Solar PV and BESS Annual Installation Constraints for Core Scenarios 1, 4, 5, and 6

	2019	2020	2021	2022-2038
Solar PV Annual Installation Limit (MW)	0	300	300	600
BESS Annual Installation Limit (MW)	60-180	300	300	600

Exhibit 6-28: Solar PV and BESS Annual Installation Constraints for Sensitivity 1 (low cost of renewable)

	2019	2020	2021	2022-2038
Solar PV Annual Installation Limit (MW)	0	300	1200	1200
BESS Annual Installation Limit (MW)	60-180	300	1200	1200

For modeling the ESM Scenario, the following limits were considered:

Exhibit 6-29: Solar PV and BESS Annual Installation Constraints for ESM Scenario

Year of Completion	2019	2020	2021	2022	2023	2024
Photovoltaic Resources (PV)						
Annual Increment (MW)	-	-	240	480	480	300
Cumulative Total (MW)			240	720	1200	1500
Battery Energy Storage Systems (BESS)						
Annual Increment (MW)	20	100	160	160	160	150
Cumulative Total (MW)	20	120	280	440	600	750

6.3.7 Levelized Cost of Energy (LCOE)

For the IRP modeling, the levelized cost of energy (LCOE) is calculated as the net present value of the unit-cost of energy over the lifetime of the solar PV asset. The LCOE is then used as a proxy for the average price that the solar PV project could break even over its lifetime. Exhibit 6-30 shows the LCOE of solar PV under Mid case and Low case. Exhibit 6-31 shows the other assumptions used in deriving the LCOE. Exhibit 6-32 shows graphically the cost trend, and Exhibit 6-33 and Exhibit 6-34 show the LCOE calculation for the base case and low case separately.

Exhibit 6-30. Levelized Cost of Energy (LCOE) of Solar PV

Levelized Cost of Energy in Puerto Rico		
Commercial On Line (COD) Year	Mid Case Solar PV 2018\$/MWh	Low Case Solar PV 2018\$/MWh
2018	69	62
2019	67	59
2020	63	56
2021	64	58
2022	67	60
2023	78	68
2024	77	67
2025	76	65
2026	76	63
2027	75	61
2028	74	59
2029	73	57
2030	72	55
2031	72	55
2032	71	54
2033	71	53
2034	70	52
2035	70	51
2036	69	50
2037	68	49
2038	68	48

Exhibit 6-31. Levelized Cost of Energy (LCOE) Assumptions

Item	Unit	Assumption
DC / AC Conversion	X	1.3
Size	MW	30
Solar Capacity Factor	%	22%
Wind Capacity Factor	%	25%
Puerto Rico Solar Overnight Cost Adder	%	16%
Solar Construction Finance Factor	%	101.5%
Wind Construction Finance Factor	%	102.5%
Small Scale Adder	%	0%
Solar PV /Wind Capital Recovery Period	year	30
Battery Storage Capital Recovery Period	year	20
\$2016 to \$2018 Conversion	X	1.035

Exhibit 6-32. Photovoltaic Levelized Cost of Energy (LCOE) 2018\$/MWh

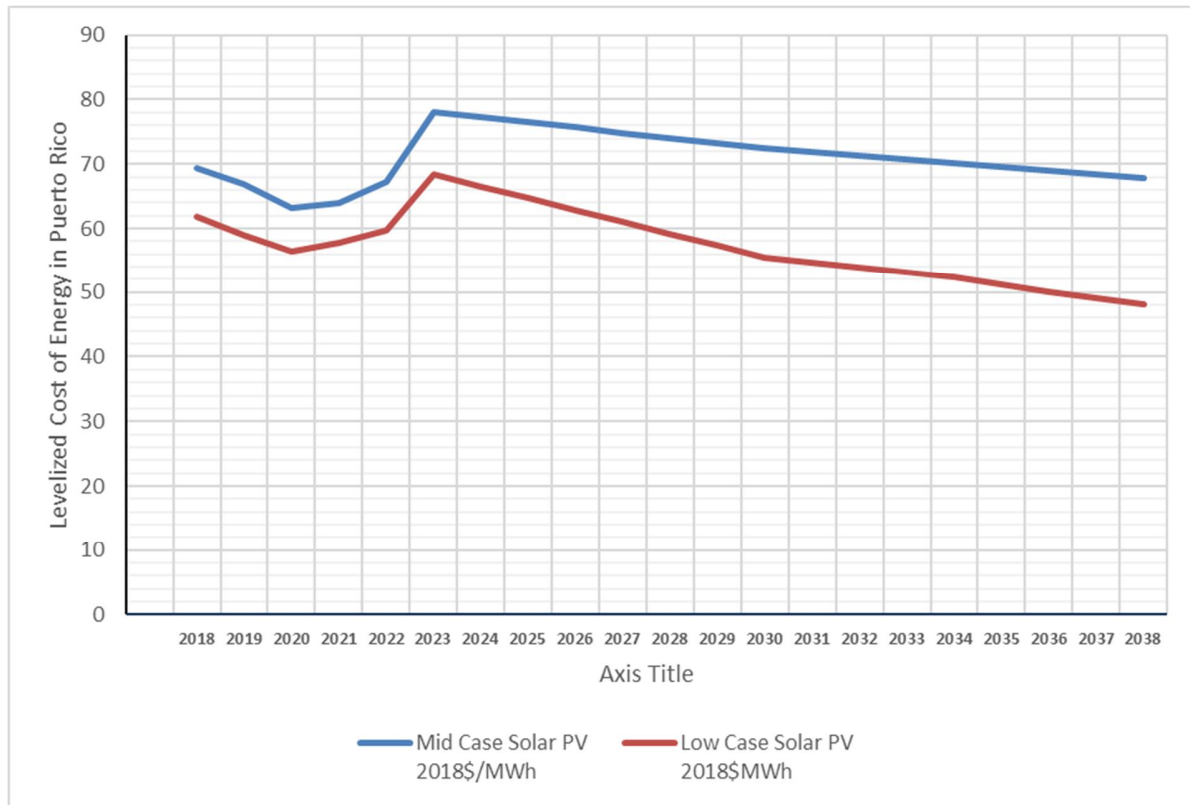


Exhibit 6-33. Levelized Cost of Energy (LCOE) of Solar PV – Base Case

Commercial on line year Construction Start Year		<u>2019</u> 2018	<u>2020</u> 2019	<u>2021</u> 2020	<u>2022</u> 2021	<u>2023</u> 2022	<u>2024</u> 2023	<u>2025</u> 2024	<u>2030</u> 2029	<u>2035</u> 2034	<u>2038</u> 2037
Capital and Operating Costs											
Overnight Cost, US National, 100 MW	\$2018/Wdc	1.05	0.98	0.93	0.92	0.91	0.90	0.89	0.84	0.80	0.78
AC/DC Conversion	X	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	\$2018/Wac	1.58	1.48	1.41	1.39	1.38	1.36	1.34	1.26	1.21	1.18
IDC Cost Adder	%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
All-In Cost, Puerto Rico, 100 MW, \$/Wac	\$2018/Wac	1.60	1.51	1.43	1.41	1.40	1.38	1.36	1.28	1.23	1.19
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	\$2018/Wac	1.60	1.51	1.43	1.41	1.40	1.38	1.36	1.28	1.23	1.19
Fixed O&M	\$2018/kW-yr	11.85	10.88	10.14	10.03	9.92	9.81	9.70	9.15	8.77	8.55
30 MW Solar PV Project Parameters											
Capacity	MW	30	30	30	30	30	30	30	30	30	30
Capacity Factor	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
Energy Produced	MWh	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816
Base Capital PV System	\$2018 thousand	48,033	45,207	42,853	42,369	41,885	41,401	40,917	38,498	36,835	35,837
Interconnection Costs	\$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Land Costs	\$2018 thousand	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562
Total PV System Capital Costs	\$2018 thousand	52,435	49,609	47,255	46,771	46,287	45,803	45,319	42,900	41,237	40,239
ITC	%	30%	30%	26%	22%	10%	10%	10%	10%	10%	10%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	71%	71%	76%	81%	97%	97%	97%	97%	97%	97%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized PV Capital Costs	\$2018 thousand	3,510	3,321	3,392	3,584	4,220	4,176	4,132	3,911	3,759	3,668
Fixed O&M	\$2018 thousand	355	327	304	301	297	294	291	274	263	256
Total Base PV System Cost	\$2018 thousand	3,866	3,648	3,697	3,885	4,517	4,470	4,422	4,186	4,023	3,925
Levelized Cost of Energy (PV Base)	\$2018/MWh	67	63	64	67	78	77	76	72	70	68

Exhibit 6-34. Levelized Cost of Energy (LCOE) of Solar PV – Low Case]

		<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2030</u>	<u>2035</u>	<u>2038</u>
Commercial on line year		2018	2019	2020	2021	2022	2023	2024	2029	2034	2037
Construction Start Year											
Capital and Operating Costs											
Overnight Cost, US National, 100 MW	\$2018/Wdc	0.91	0.87	0.83	0.81	0.79	0.76	0.74	0.62	0.56	0.53
AC/DC Conversion	X	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	\$2018/Wac	1.38	1.31	1.26	1.22	1.19	1.15	1.11	0.94	0.85	0.79
IDC Cost Adder	%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
All-In Cost, Puerto Rico, 100 MW, \$/Wac	\$2018/Wac	1.40	1.33	1.28	1.24	1.20	1.17	1.13	0.95	0.86	0.80
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	\$2018/Wac	1.40	1.33	1.28	1.24	1.20	1.17	1.13	0.95	0.86	0.80
Fixed O&M	\$2018/kW-yr	10.45	9.69	9.10	8.85	8.61	8.36	8.12	6.89	6.30	5.89
30 MW Solar PV Project Parameters											
Capacity	MW	30	30	30	30	30	30	30	30	30	30
Capacity Factor	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
Energy Produced	MWh	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816
Base Capital PV System	\$2018 thousand	41,885	39,933	38,273	37,189	36,105	35,021	33,937	28,517	25,935	24,116
Interconnection Costs	\$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Land Costs	\$2018 thousand	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562
Total PV System Capital Costs	\$2018 thousand	46,287	44,335	42,675	41,591	40,507	39,423	38,339	32,919	30,337	28,518
ITC	%	30%	30%	26%	22%	10%	10%	10%	10%	10%	10%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	71%	71%	76%	81%	97%	97%	97%	97%	97%	97%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized PV Capital Costs	\$2018 thousand	3,099	2,968	3,064	3,187	3,693	3,594	3,495	3,001	2,766	2,600
Fixed O&M	\$2018 thousand	314	291	273	266	258	251	243	207	189	177
Total Base PV System Cost	\$2018 thousand	3,412	3,259	3,337	3,453	3,951	3,845	3,739	3,208	2,955	2,777
Levelized Cost of Energy (PV Base)	\$2018/MWh	59	56	58	60	68	67	65	55	51	48

6.3.8 Minimum Technical Requirements (MTR)

Renewable energy projects in Puerto Rico must comply with minimum technical requirements (MTR) to allow for their integration into the island's grid. In addition to the frequency ride through, voltage ride through and voltage regulation requirements, the MTR require the renewable generation to contribute to frequency response and most importantly limits its ramps to 10% of the project's Contractual Capacity per minute for both increase and decreases in production. This last requirement is subject to the limitations of the Battery Energy Storage System (BESS) with a Nominal Storage Capacity (NSC) equal to 30% of the Contractual Capacity and an Effective Storage Capacity (ESC) of 45% of the Contractual Capacity, deliverable for up to 1 minute. The ramp control poses the highest demands of active power and energy on the BESS and defines its size and cost.

The minimum energy requirements for ramp control could be assessed considering a situation where a project is delivering 100% of its capacity and due to a rapid cloud cover the output drops to practically zero. In this case the requirement becomes the Effective Storage Capacity (ESC) for one minute and then the Nominal Storage Capacity (NSC) for the balance of the time until the output is taken down to zero. However, from a practical perspective, an energy output equal to $10 \text{ min} \times 30\%$ Project Capacity, would cover this requirement and leave some margin.

However, in the IRP Siemens expects that important levels of BESS will be installed in the system with the dual purpose of providing frequency regulation and shifting energy from day peak to night peak. Thus, modelling the frequency regulation and ramp rate control related MTRs in the IRP including the requirement for storage may result in inefficiencies particularly considering that: a) the investments in the balance of system (BOS) that includes the Power Conversion System (PCS) are similar regardless the energy storage is 10 minutes or 4 hours, making the second much more competitive and b) linking the renewable additions with a BESS may result in investments beyond the actual requirements for the system. Therefore, in the context of this IRP, the solar PV projects and the storage projects are considered separately with the consideration that, during the Request for Proposals (RFPs) to be issued during the implementation phase for solar PV projects, the required component of storage for its integration shall be added, with the flexibility for bidders to bid on one or both components.

PREPA should not commission neither allow the interconnection of PV solar or wind projects to the grid until the required corresponding energy storage component be commissioned and interconnected in full compliance with the energy storage technical requirements. It is also very important to emphasize that the solar PV projects shall still comply with the MTRs related with frequency ride through, voltage ride through, reactive power capability and voltage regulation in addition to their full compliance with the frequency regulation and frequency response requirements to be met by either separate or integrated energy storage. This approach is expected to foster competition and innovation while at the same time ensuring that the required regulation and energy shifting will be available for the PV integration before its interconnection.

6.4 Battery Storage

The goal of moving toward a low carbon future is leading to a proliferation of utility-scale solar PV and wind generation, and growing levels of distributed energy resources (DER) behind the meter. These developments are challenging the historical centralized paradigm for how a utility should design, build and manage an electricity system. Without the proper foundation of utility-integrated energy storage and software controls, renewable energy resources could face technical and operational challenges and curtailment of highly valued carbon-free electricity could be required in order for the utility to maintain system stability and reliability.

Energy storage technologies can prove valuable to utilities in managing such change as these technologies have the ability to decouple energy supply and demand, and thus provide a valuable resource to system operators. Energy storage could serve as generation or load and to produce or absorb both real and reactive power. Currently, Li-ion batteries are the most relevant battery technology with wide applications in power electronics, electric vehicles (EVs), and stationary storage (grid-scale).

6.4.1 Installed Costs and Applications

While energy storage costs and performance data are global in nature, the results presented here are most representative of the current U.S. energy storage market. The key individual costs making up the total energy storage system costs are detailed below:

Capital costs: The capital costs are for the entirety of the Battery Energy Storage System (BESS), which comprises the battery cell, the Power Conversion System (PCS) costs, and the related EPC costs. The battery energy storage system costs include the storage module (SM) and the balance of system (BOS) costs.

Augmentation costs: Augmentation costs represent the additional BESS equipment needed to maintain the usable energy capability to cycle the unit according to the usage profile in the particular use case, for the life of the system. Additional equipment is required in the following circumstances: (1) if the particular unit charges or discharges to a level less than its rated energy capacity (kWh) per cycle; (2) if the battery chemistry does not have the cycle-life needed to support the entire operating life of the use case; or (3) if the energy rating (kWh) of the battery chemistry degrades due to usage and can no longer support the intended application. This time-series of varying costs is then converted into a level charge over the life of the system to provide greater clarity for project developers.

Operating costs: These include the O&M costs, charging costs, and costs of extended warranties for the major equipment.

Other costs: These include financing costs (debt service payments), taxes paid, costs of meeting local and regional regulatory requirements, and warranty costs.

The costs of energy storage systems are based on specific selected grid applications and the power rating and usage duration assumptions are given below:

Peaker replacement: Large-scale energy storage system designed to replace peaking gas turbine facilities; brought online quickly to meet rapidly increasing demand for power at peak; can be quickly taken offline as power demand diminishes.

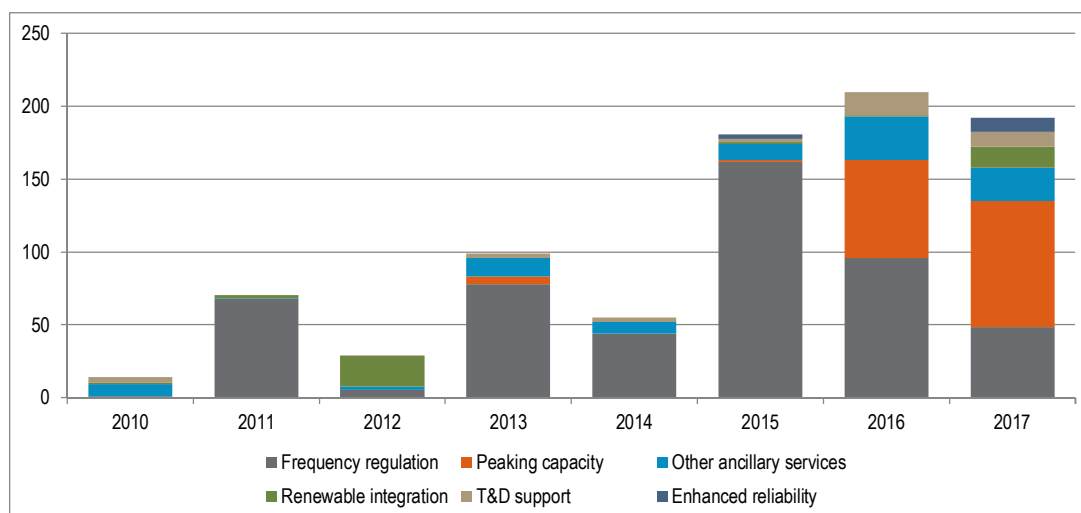
Distribution: Energy storage system designed to defer distribution upgrades, typically placed at substations or distribution feeder controlled by utilities to provide flexible peaking capacity, while also mitigating stability problems.

Microgrid: Energy storage system designed to support small power systems that can “island” or otherwise disconnect from the broader power grid (e.g., military bases, universities, etc.), to provide energy shifting, ramping support to enhance system stability, and increase reliability of service (emphasis is on short-term power output vs. load shifting, etc.).

While the majority of installed capacity provides frequency regulation, recent projects have targeted alternative applications including peaking capacity, renewable integration, and peak shaving. Exhibit

6-35 shows the primary application for installed storage capacity in recent history. The primary application is defined as the service that motivated the project, generally the highest-value or most profitable service. The category “other ancillary services” includes voltage support, black start, and operating reserves; and the category “renewable integration” is primarily energy shifting.

Exhibit 6-35. U.S Installed Capacity (MW) by Primary Application



Source: Siemens, IHS Markit

6.4.2 Future Cost Trends

Battery costs (\$/kWh) can be lowered either by reducing the cost of the battery modules and balance of system (reducing \$) or by improving the battery performances (increasing kWh) or by a combination of the two approaches.

Cost of batteries can be further reduced relative to where they are today by focusing on the battery modules and battery parts. However, it should be noted that extracting further cost reductions for the balance of system is going to prove increasingly difficult as the battery parts and materials become increasingly commoditized. The following options can be pursued to reduce battery cost:

- Using cheaper materials to build battery parts e.g. electrodes, electrolytes, separators, etc.
- Improving the supply chain and making the manufacturing processes for battery modules more cost effective
- Increasing the scale of manufacturing to spread the capital and fixed O&M costs over a very large number of modules produced

Battery performance can be further improved relative to where it is today, and this needs to be accomplished while keeping the costs comparable to today’s technologies. The following avenues are being pursued to improve battery performance:

- Technological improvements, advances or breakthroughs, that lead to better performance, (e.g., cycle life, higher safety, more environmentally friendly, higher energy density, increasing voltage, and higher power density);

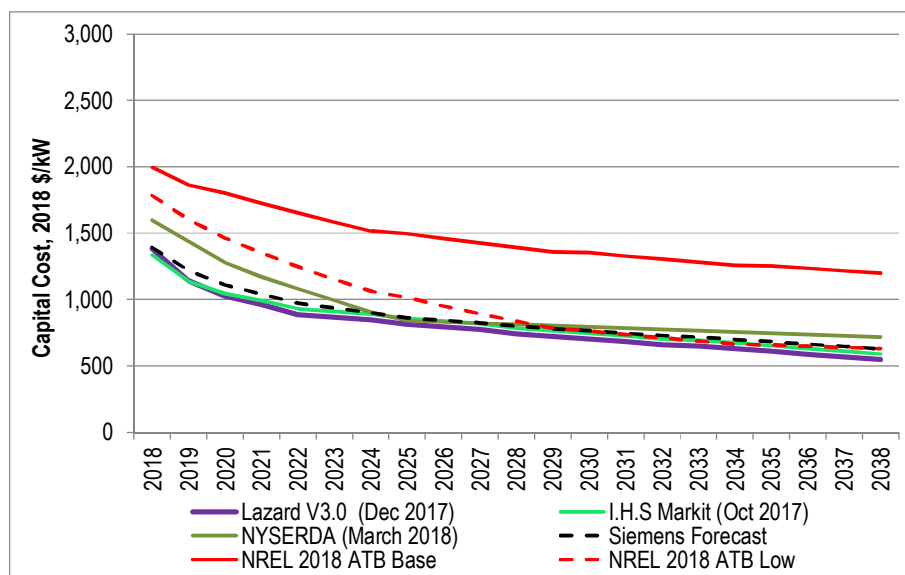
- Using better, more stable materials to build battery parts, (e.g., electrodes, electrolytes, and separators) that are able to deliver the better performance listed above;
- Using more effective chemistries, formulations, or crystal structures that overcome some of the limitations of today's technologies; and
- Using more stable solid electrolytes that enable higher voltages, reduce flammability, and make pure metal (e.g., lithium) anodes safer.

6.4.3 Li-ion Battery System Price Forecast

Li-ion batteries are, and are expected to remain, the mainstream technology for electrochemical energy storage. The support this technology has gathered at both the policy and industrial level is strong enough to keep it going for years to come. Multi-billion-dollar investments are already in place and a quiet arms race is in place to take the place of established Japanese and Korean battery companies, with the biggest threat being from China. Though medium-term shortages of raw materials such as cobalt may increase this portion of the cost somewhat, the larger declines driven by increased scale of production and intense worldwide competition, is likely to drive down the prices overall. As both the stationary energy storage and electric vehicle volumes begin to increase, new low-cost manufacturing facilities will continue to be built, particularly in China, which is expected to help prices continue to fall, albeit at a more temperate rate (~ 10–20% per year) through 2022. Beyond 2022, as economies of scale are maximized and technology improvements slow, battery prices are expected to approach the bottom and stabilize, limiting the decline to less than 5% a year.

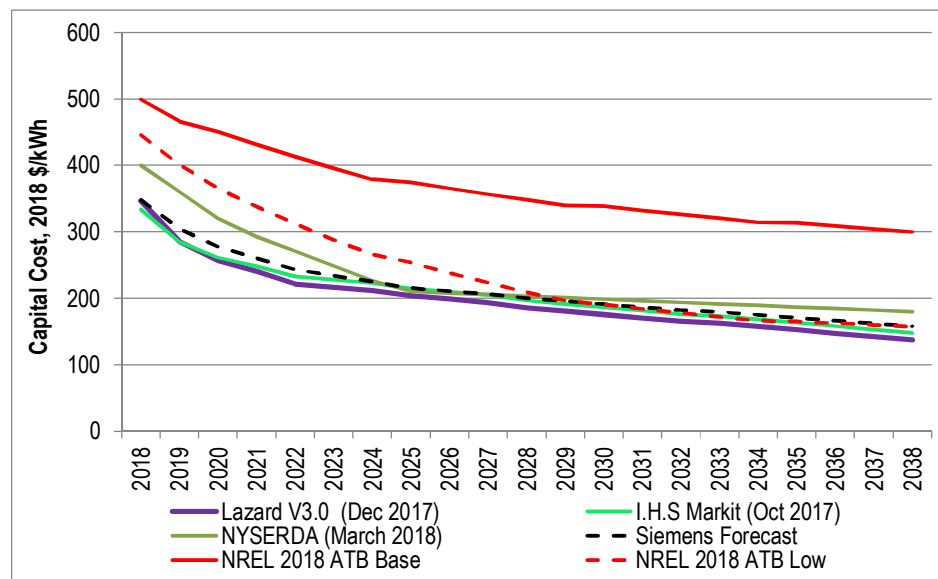
The Exhibits below represent Siemens view of 4-hour 1 MW Li-Ion battery system price forecasts, in \$/kW and \$/kWh, respectively, in comparison with multiple other forecasts.

Exhibit 6-36-. 4-hour Li-ion Battery System Capital Cost Forecasts



Source: Siemens, IHS, Lazard, NYSERDA, NREL

Exhibit 6-37. 4-hour Li-ion Battery System Capital Cost Forecasts



Note: The capital cost (\$/kW) is converted to LCOE (\$/kWh) based on the 4-hour cycle of the battery storage.

Source: Siemens, IHS, Lazard, NYSERDA, NREL

Exhibit 6-38 and Exhibit 6-39 present the capital and operating costs assumptions of 2-hour, 4-hour and 6-hour storage in the base case and low case, respectively.

Exhibit 6-38. Li-Ion Battery System Capital Cost and Operating Cost Assumptions – Base Case

Construction Year	All-in Capital Costs			Operating Costs	
	4-hour Li-ion Battery Storage 2018\$/KW	2-hour Li-ion Battery Storage 2018\$/KW	6-hour Li-ion Battery Storage 2018\$/KW	Fixed Operating Costs 2018\$/kW-year	Variable Operating Costs 2018\$/MWh
2018	1,392	832	1,953	9.09	2.67
2019	1,218	734	1,703	8.96	2.60
2020	1,110	674	1,546	8.95	2.58
2021	1,041	635	1,447	8.81	2.51
2022	972	596	1,349	8.67	2.43
2023	936	576	1,296	8.54	2.36
2024	899	556	1,243	8.41	2.29
2025	861	534	1,188	8.40	2.28
2026	843	523	1,163	8.26	2.20
2027	825	512	1,138	8.12	2.13
2028	800	496	1,104	7.99	2.06
2029	782	485	1,079	7.86	1.99
2030	764	474	1,054	7.85	1.97
2031	746	462	1,031	7.71	1.90
2032	728	450	1,007	7.57	1.82
2033	717	443	992	7.44	1.75
2034	700	431	969	7.31	1.69
2035	682	419	945	7.30	1.67
2036	664	407	922	7.19	1.64
2037	647	395	898	7.08	1.62
2038	629	383	875	6.97	1.59

Source: Siemens, NREL

Exhibit 6-39. Li-Ion Battery System Capital Cost and Operating Cost Assumptions – Low Case

Construction Year	All-in Capital Costs			Operating Costs	
	4-hour Li-ion Battery Storage 2018\$/KW	2-hour Li-ion Battery Storage 2018\$/KW	6-hour Li-ion Battery Storage 2018\$/KW	Fixed Operating Costs 2018\$/kW-year	Variable Operating Costs 2018\$/MWh
2018	1,236	756	1,716	8.52	2.55
2019	1,047	651	1,443	8.22	2.45
2020	931	588	1,275	8.15	2.42
2021	857	549	1,165	7.81	2.31
2022	779	506	1,053	7.49	2.19
2023	743	488	997	7.18	2.09
2024	701	467	935	6.88	1.99
2025	664	448	880	6.80	1.95
2026	643	438	848	6.46	1.84
2027	623	428	818	6.14	1.73
2028	594	411	777	5.84	1.62
2029	573	400	746	5.55	1.53
2030	553	389	717	5.45	1.49
2031	536	375	696	5.11	1.37
2032	513	358	668	4.80	1.26
2033	497	345	650	4.50	1.16
2034	483	334	633	4.22	1.07
2035	465	319	610	4.10	1.02
2036	450	307	593	4.04	1.00
2037	437	296	578	3.98	0.99
2038	418	280	555	3.92	0.97

Source: Siemens, NREL

6.5 Wind Projects

As per the order by the Puerto Rico Energy Bureau (PREB)³³, wind resources are evaluated to in the economic competition with all other options, including fossil and other renewables. The cost estimates for utility scale wind projects were developed with the following steps: 1) establish baseline onshore wind projects operating and overnight capital costs estimate; 2) evaluate interconnection costs specific to Puerto Rico; 3) assess construction and financing costs reflecting Puerto Rico specific assumptions; and 4) calculate Levelized Cost of Energy (LCOE) for wind projects in Puerto Rico.

6.5.1 Baseline Operating and Overnight Capital Costs

For step 1, the IRP assumes overnight capital costs and operating costs for onshore wind projects consistent with the NREL 2018 ATB as shown in Exhibit 6-40.

³³ Dated September 18, 2018

Exhibit 6-40. U.S. Utility Scale Wind Projects Costs Assumptions

NREL 2018 Annual Technology Baseline (ATB) Mid Case			NREL 2018 Annual Technology Baseline (ATB) Low Case		
Year	Onshore Wind Overnight Capital Costs 2018\$/KW	Fixed Operating Costs 2018\$/kW-year	Year	Onshore Wind Overnight Capital Costs 2018\$/KW	Fixed Operating Costs 2018\$/kW-year
2018	1,731	52.36	2018	1,733	51.22
2019	1,733	51.98	2019	1,731	50.45
2020	1,736	51.60	2020	1,716	49.69
2021	1,738	51.22	2021	1,655	48.92
2022	1,741	50.83	2022	1,592	48.16
2023	1,744	50.45	2023	1,527	47.39
2024	1,747	50.07	2024	1,459	46.63
2025	1,749	49.69	2025	1,390	45.87
2026	1,752	49.31	2026	1,318	45.10
2027	1,755	48.92	2027	1,244	44.34
2028	1,758	48.54	2028	1,120	43.57
2029	1,761	48.16	2029	1,080	42.81
2030	1,764	47.78	2030	1,048	42.04
2031	1,768	47.39	2031	1,024	41.66
2032	1,771	47.01	2032	1,009	41.28
2033	1,774	46.63	2033	1,006	40.90
2034	1,777	46.25	2034	1,004	40.51
2035	1,781	45.87	2035	1,001	40.13
2036	1,784	45.48	2036	998	39.75
2037	1,788	45.10	2037	995	39.37
2038	1,792	44.72	2038	993	38.99
2039	1,795	44.34	2039	990	38.60

Source: NREL 2018 ATB, converted to \$2018. (<https://atb.nrel.gov/electricity/data.html>)

6.5.2 Investment Tax Credit (ITC)

Consistent with the current policy, the IRP assumes the following: wind facilities that commence construction by December 31, 2018 will qualify for 18 percent ITC; wind facilities that commence construction by December 31, 2019 will be reduced to 12 percent ITC; and zero percent afterwards.³⁴

6.5.3 Project Development and Construction Time

The IRP assumes an accelerated timeline for wind projects similar to the solar PV projects, assuming 12 months for the development period (request for proposal, bid evaluation, permitting, and financing) and 12 months for construction.

6.5.4 Levelized Cost of Energy (LCOE)

For the IRP modeling, the levelized cost of energy (LCOE) is calculated as the net present value of the unit-cost of energy over the lifetime of the wind asset. The LCOE is then used as a proxy for the average price that the wind project could break even over its lifetime. Exhibit 6-41 shows the LCOE of wind under Mid case and Low case, determined using an expected capacity factor of 25% which is in line with observed values in the two existing Puerto Rico wind projects.

³⁴ <http://programs.dsireusa.org/system/program/detail/658>

Exhibit 6-41. Levelized Cost of Energy (LCOE) of Wind

Levelized Cost of Energy in Puerto Rico		
Commercial On Line (COD) Year	Mid Case Wind 2018\$/MWh	Low Case Wind 2018\$/MWh
2018	104	103
2019	111	110
2020	118	116
2021	132	126
2022	132	122
2023	132	118
2024	132	114
2025	132	110
2026	132	105
2027	132	101
2028	132	93
2029	132	90
2030	132	88
2031	132	87
2032	132	86
2033	132	85
2034	132	85
2035	132	84
2036	131	84
2037	131	84
2038	131	83

Exhibit 6-42 shows a comparison of the LCOE of wind with Solar PV. Note that even the Low Case for Wind is expected to be above the Mid Case for Solar PV. Moreover, a capacity factor of 30% would be required for the Low Wind Case to reach the same levels as the Mid Case Solar PV and approximately 40% for the Wind Low Case to reach the PV Low Case. Given that capacity factors at 30% or above are not expected in Puerto Rico and the model is assuming 23% at this time, Siemens doesn't expect that AURORA's LTCE will pick a wind alternative. Moreover, as shown in Exhibit 6-43, the wind generation in Puerto Rico is in general daytime peaking, making it correlated with Solar PV and reducing any diversity benefits.

Finally, Exhibit 6-44 and Exhibit 6-45 show the LCOE calculation for the Mid Case and Low Case, respectively, for Wind Turbine generation.

**Exhibit 6-42. Wind and Photovoltaic Levelized Cost of Energy (LCOE)
\$2018/MWh**

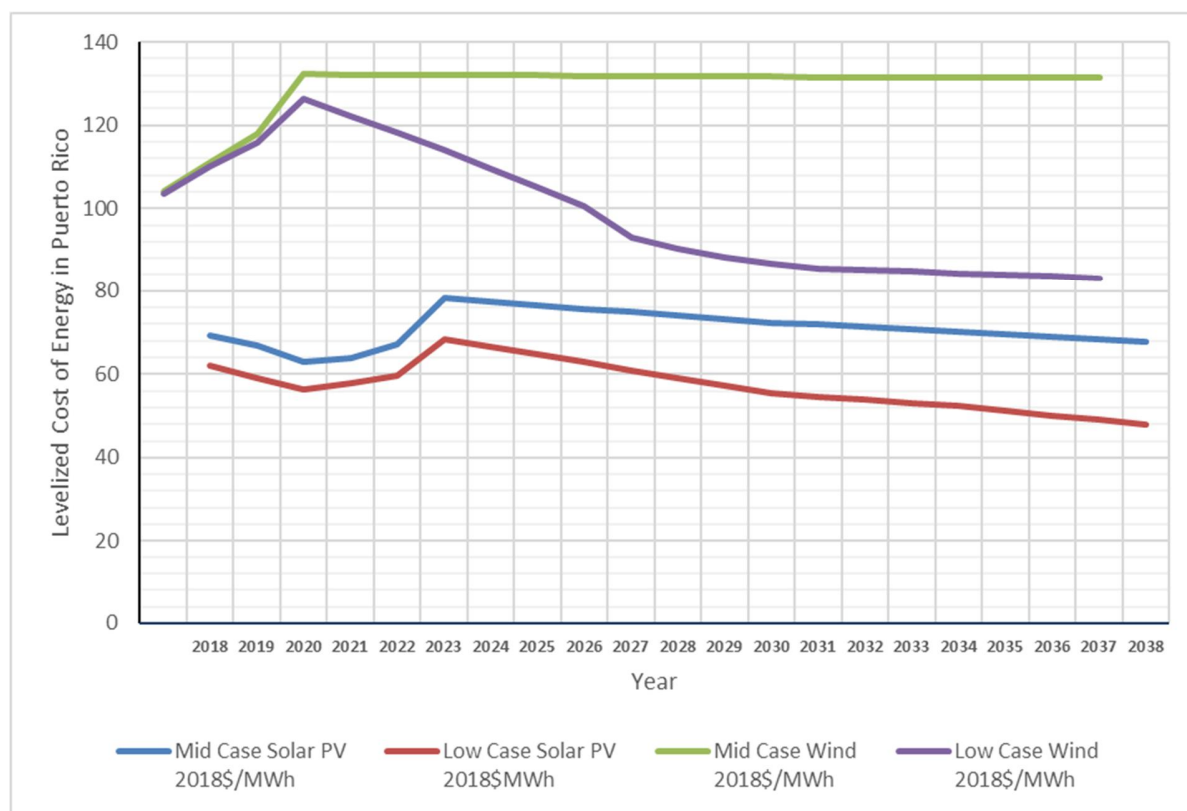


Exhibit 6-43. Average hourly output at Santa Isabel per Month

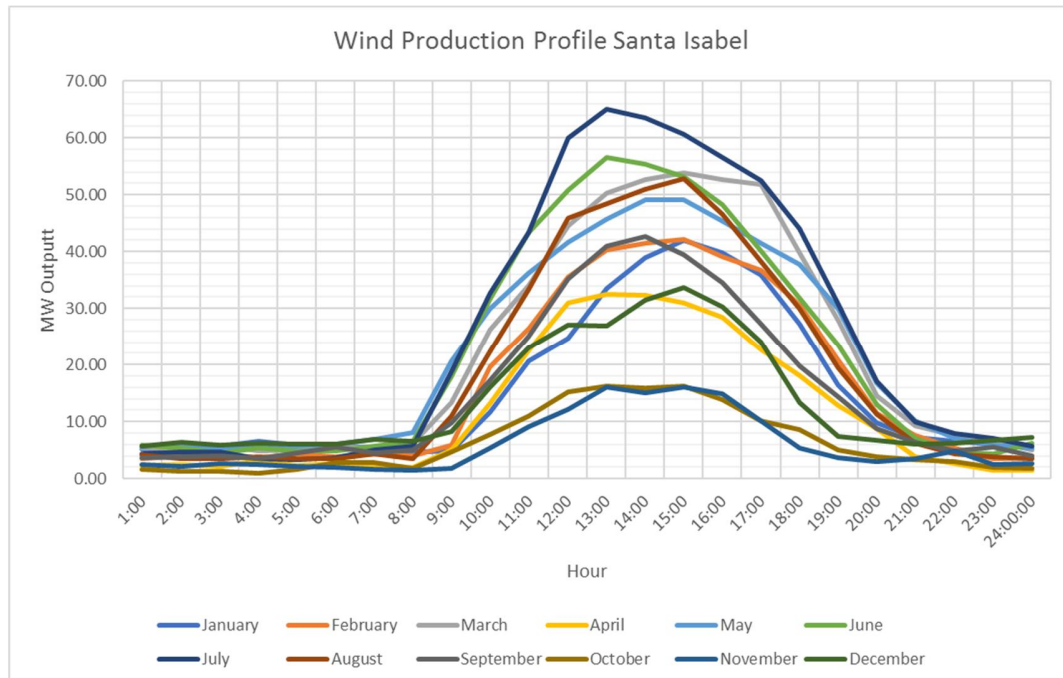


Exhibit 6-44. Levelized Cost of Energy (LCOE) of Wind Generation – Base Case

Commercial on line year Construction Start Year		<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2030</u>	<u>2035</u>	<u>2038</u>
		2018	2019	2020	2021	2022	2023	2024	2029	2034	2037
Capital and Operating Costs											
Overnight Cost, US National, 100 MW	\$2018/Watt	1.73	1.74	1.74	1.74	1.74	1.75	1.75	1.76	1.78	1.79
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	\$2018/Watt	2.01	2.01	2.02	2.02	2.02	2.03	2.03	2.05	2.07	2.08
IDC Cost Adder	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
All-In Cost, Puerto Rico, 100 MW, \$/Wac	\$2018/Watt	2.06	2.06	2.07	2.07	2.07	2.08	2.08	2.10	2.12	2.13
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	\$2018/Watt	2.06	2.06	2.07	2.07	2.07	2.08	2.08	2.10	2.12	2.13
Fixed O&M	\$2018/kW-yr	67.58	67.08	66.58	66.08	65.59	65.09	64.59	62.11	59.63	58.13
30 MW Wind Project Parameters											
Capacity	MW	30	30	30	30	30	30	30	30	30	30
Capacity Factor	%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Energy Produced	MWh	65,700	65,700	65,700	65,700	65,700	65,700	65,700	65,700	65,700	65,700
Base Capital System	\$2018 thousand	61,806	61,895	61,986	62,080	62,176	62,274	62,375	62,910	63,500	63,881
Interconnection Costs	\$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Total System Capital Costs	\$2018 thousand	64,646	64,735	64,827	64,920	65,016	65,115	65,215	65,750	66,341	66,722
ITC	%	18%	12%	0%	0%	0%	0%	0%	0%	0%	0%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	86%	94%	109%	109%	109%	109%	109%	109%	109%	109%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized Capital Costs	\$2018 thousand	5,267	5,745	6,695	6,705	6,715	6,725	6,735	6,790	6,851	6,891
Fixed O&M	\$2018 thousand	2,027	2,012	1,997	1,983	1,968	1,953	1,938	1,863	1,789	1,744
Total Base System Cost	\$2018 thousand	7,295	7,757	8,692	8,687	8,682	8,677	8,673	8,654	8,640	8,635
Levelized Cost of Energy (Base)	\$2018/MWh	111	118	132	132	132	132	132	132	132	131

Exhibit 6-45. Levelized Cost of Energy (LCOE) of Wind Generation – Low Case

		<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2030</u>	<u>2035</u>	<u>2038</u>
Commercial on line year		2018	2019	2020	2021	2022	2023	2024	2029	2034	2037
Construction Start Year											
Capital and Operating Costs											
Overnight Cost, US National, 100 MW	\$2018/Watt	1.73	1.72	1.65	1.59	1.53	1.46	1.39	1.05	1.00	0.99
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	\$2018/Watt	2.01	1.99	1.92	1.85	1.77	1.69	1.61	1.22	1.16	1.15
IDC Cost Adder	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
All-In Cost, Puerto Rico, 100 MW, \$/Wac	\$2018/Watt	2.06	2.04	1.97	1.89	1.81	1.73	1.65	1.25	1.19	1.18
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	\$2018/Watt	2.06	2.04	1.97	1.89	1.81	1.73	1.65	1.25	1.19	1.18
Fixed O&M	\$2018/kW-yr	65.59	64.59	63.60	62.61	61.61	60.62	59.63	54.66	52.17	50.68
30 MW Wind Project Parameters											
Capacity	MW	30	30	30	30	30	30	30	30	30	30
Capacity Factor	%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Energy Produced	MWh	65,700	65,700	65,700	65,700	65,700	65,700	65,700	65,700	65,700	65,700
Base Capital System	\$2018 thousand	61,721	61,180	59,003	56,755	54,431	52,029	49,551	37,360	35,685	35,390
Interconnection Costs	\$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Total System Capital Costs	\$2018 thousand	64,562	64,020	61,843	59,596	57,271	54,870	52,391	40,201	38,525	38,230
ITC	%	18%	12%	0%	0%	0%	0%	0%	0%	0%	0%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	86%	94%	109%	109%	109%	109%	109%	109%	109%	109%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized Capital Costs	\$2018 thousand	5,260	5,681	6,387	6,155	5,915	5,667	5,411	4,152	3,979	3,948
Fixed O&M	\$2018 thousand	1,968	1,938	1,908	1,878	1,848	1,819	1,789	1,640	1,565	1,520
Total Base System Cost	\$2018 thousand	7,228	7,619	8,295	8,033	7,763	7,485	7,199	5,791	5,544	5,469
Levelized Cost of Energy (Base)	\$2018/MWh	110	116	126	122	118	114	110	88	84	83

Part 7

Assumptions and Forecasts

This Part provides two remaining aspects necessary for the IRP, fuel infrastructure forecast and an estimation of the Value of Lost Load (VOLL) for Puerto Rico.

7.1 Fuel Infrastructure and Forecast

7.1.1 Fuel Infrastructure Options

The purpose of this review is to identify the requirements for using or developing the fuel infrastructure needed to support the generation options considered in the IRP. Specific objectives include:

- Identify current fuel infrastructure options;
- Evaluate sources of natural gas delivered to Puerto Rico such as liquefied natural gas (LNG);
- Identify LNG or natural gas transport infrastructure needs relative to key generation sites at Aguirre and Costa Sur in the south, San Juan and Palo Seco in the north, Mayagüez in the west, and Yabucoa in the east; and
- Review alternative liquid fuels' attractiveness and deliverability.

As a power generation fuel, natural gas is superior to petroleum products like diesel and residual fuel oil because it has lower air emissions, higher efficiency, greater operating flexibility, and lower costs. The inherent sulfur and particulate content of natural gas processed as LNG is extremely low. Carbon dioxide emissions from natural gas combustion are also lower relative to liquid fuels.³⁵ With state-of-the-art controls such as low-NO_x burners, NO_x emissions can be lower as well. Natural gas allows the use of advanced combined cycle technology (although diesel can be used as a fuel for less advanced combined cycle technology), which is the most fuel-efficient thermal power generation technology available today.³⁶ Advanced gas turbines cannot fire residual fuel oil because of its high ash content. In addition, natural gas has been significantly less expensive since 2009 compared to premium liquid fuels such as diesel and residual fuel oil, primarily due to the shale gas boom in the U.S. (see Exhibit 7-2). However, the benefits of natural gas can be realized only if it can be delivered in a cost-effective manner to Puerto Rico and then distributed to power generation sites. The need to expand the island's LNG import capability and natural gas distribution

³⁵ According to the EIA (https://www.eia.gov/environment/emissions/co2_vol_mass.php), natural gas emits 67%, 73%, and 84% of the CO₂ as compared to residual fuel oil, diesel, and propane, respectively.

³⁶ The EIA (https://www.eia.gov/electricity/annual/html/epa_08_02.html) reports that current natural gas-fired combined cycle plants have an average heat rate of 7,652 Btu/kWh vs. 9,179 Btu/kWh for internal combustion and 11,214 Btu/kWh for gas turbine.

pipelines would require significant new fuel infrastructure investments in order to realize Puerto Rico's potential benefit from greater natural gas use for power generation.

The U.S. mainland currently has two LNG export terminals in operation and four more under construction; collectively representing 71.05 million tons per annum (MMtpa) of nameplate capacity that will be online by 2021. More than 300 MMtpa of additional capacity has been proposed, most of which will not be realized but some of which may constitute a second wave of liquefaction capacity buildout in the mid- to late-2020s. Exhibit 7-1 below describes the existing LNG capacity in the mainland U.S. The total contracted capacity is equal to 63.08 MMtpa or 88.8% of nameplate capacity. While this leaves nearly 8 MMtpa of uncontracted capacity that could potentially satisfy Puerto Rico's LNG demand (estimated to be no higher than 6.5 MMtpa), these U.S.-based LNG export facilities would require Jones Act-compliant ships to ferry LNG to Puerto Rico. The Jones Act requires goods traveling between U.S. ports to do so on ships constructed and flagged in America, with primarily U.S. crews. However, there are not any Jones Act-compliant, large-scale U.S. vessels that can carry LNG in large onboard tanks. In addition, no American shipyard has constructed an LNG carrier in nearly four decades (although there are U.S. vessels that could carry LNG in ISO containers). This reason, among others, is why Puerto Rico primarily receives its LNG supply from Trinidad & Tobago. Exhibit 7-1 summarizes total and contracted U.S. export facility capacity by terminal.

Exhibit 7-1. U.S. Mainland Large-Scale LNG Export Capacity (MMtpa)

LNG Facility	Status	Nameplate Capacity	Contracted Capacity
Sabine Pass	Operational	22.5	19.8
Dominion Cove Point	Operational	5.3	4.6
Freeport	Under Construction	15.3	13.6
Cameron	Under Construction	12.0	12.0
Corpus Christi	Under Construction	13.5	10.6
Elba Island	Under Construction	2.5	2.5

Source: Siemens.

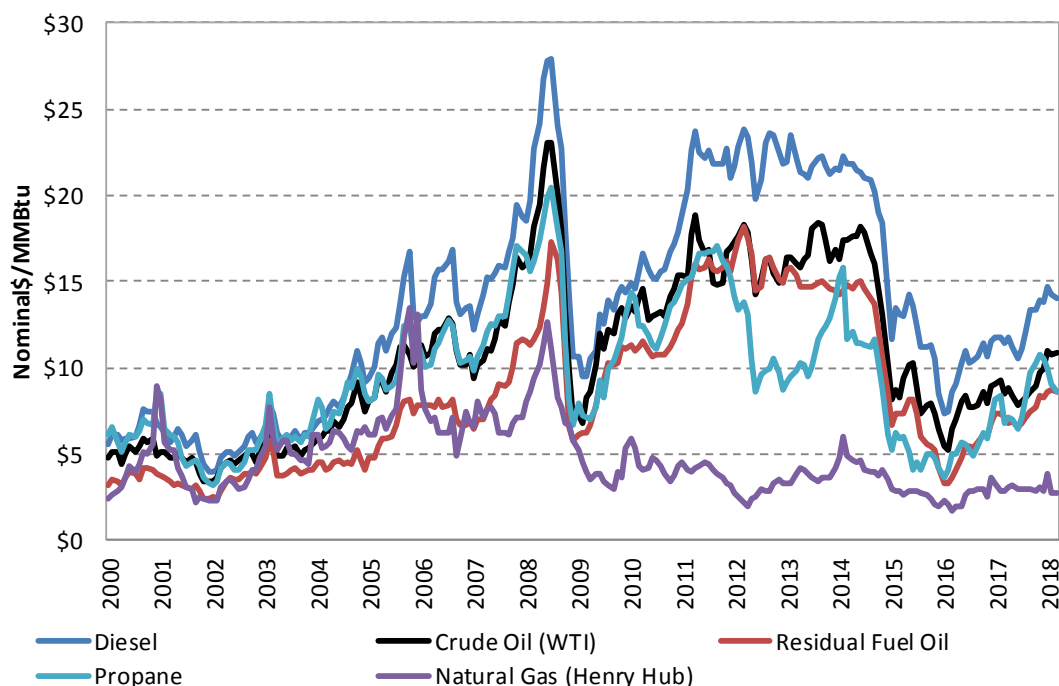
LNG terminals and infrastructure can play an important role in sourcing cleaner and less expensive LNG. Robust options for natural gas supply provide flexibility to enhance security of supply (backup) to each generating site, as well as commercial value in negotiating and selecting the most advantageous pricing over time among various fuel suppliers.

The EcoEléctrica LNG Import Terminal has been operating successfully since 2000. In 2017, the Federal Energy Regulatory Commission (FERC) approved a change in operations to expand the terminal's natural gas send-out beyond its own 507 MW combined cycle unit to include supply to PREPA's 820 MW Costa Sur generating plant. The terminal send-out capacity was increased by 93 MMcf/d, from 186 MMcf/d to 279 MMcf/d, by putting into service an idle gasifier (the third such gasifier) and can be expanded by a further 93 MMcf/d by putting into service the remaining spare gasifier (the fourth such gasifier). EcoEléctrica delivers 186 MMcf/d of regasified LNG to the Costa Sur plant through a renegotiated contract (as of May 2018, Costa Sur is running exclusively on natural gas) while the remaining 93 MMcf/d supplies its own combined cycle plant. Beyond the maximum send-out capacity of 372 MMcf/d (if the fourth gasifier is put into service), a major increase in LNG terminal

throughput could require some modifications, possibly including a second LNG storage tank³⁷. It must be noted that EcoEléctrica is a private company and expanded natural gas supply from this terminal would require PREPA, at a minimum, to contractually commit to a long-term natural gas processing and/or purchase agreement to justify infrastructure investments.

Fuel (including diesel and residual fuel oil) together with purchased power is the predominant cost and most volatile rate component for PREPA. Reducing dependence on oil for power generation has long been a top priority for PREPA. Although progress has been made, oil remains the main source of energy generation. An estimated 45% of generation is from oil, compared to the national average of 4%. PREPA has an aspirational goal of a 20-25% cost reduction (\$400-500 million) from fuel and purchased power under pre-storm conditions by FY 2023. One component, purchased power, is under two long-term Power Purchase Agreements (PPAs) that extend through 2022 and 2027, respectively, and thus are not easily altered. Fuel prices are the other component and have been historically volatile, particularly oil and its derivative diesel and residual fuel oil products. Prices have been increasing since a recent low point in 2016. Exhibit 7-2 below provides a comparison of the U.S. fuel prices from 2000 to March 2018 on an energy-equivalent nominal \$/MMBtu basis. Natural gas has been the least-cost of these five fuels consistently for nearly a decade and in more recent history has exhibited significantly less price volatility.

Exhibit 7-2. U.S. Fuel Prices (Nominal \$/MMBtu)



³⁷ A second LNG tank was included in the original permit but was not constructed, and the permit has expired. So, a new permitting effort would be required for such an expansion.

Source: Siemens, EIA.

Puerto Rico's electrical infrastructure was critically damaged during September 2017, when Hurricanes Irma and Maria delivered back-to-back blows to the Island, resulting in a complex and prolonged disaster recovery effort. Hurricane Irma skirted the northern coast of the Island from September 6–7, 2017 as a Category 5 storm, causing significant flooding, regional power and water outages, and other impacts to the Island's infrastructure. Exactly 13 days later, on September 20th, and before Irma's response operations had concluded, Hurricane Maria slammed into Puerto Rico, making a direct strike as a strong Category 4 storm causing widespread devastation.

The following sections describe the pre-storm fuel infrastructure as well as proposed fuel infrastructure during the recovery and rebuilding phases after the storms.

7.1.2 Pre-Storm Fuel Infrastructure

7.1.2.1 Residual Fuel Oil (No. 6 Fuel Oil)

Puerto Rico has three steam-electric power plants which burn residual fuel oil. These are Palo Seco and San Juan in the north and Aguirre located on the south coast. The Costa Sur plant, located on the southwestern coast, is dual-fuel, capable of burning either residual fuel oil or natural gas. However, as of May 2018 it is burning exclusively natural gas. The San Juan and Aguirre facilities have additional combined-cycle plants that burn diesel. Residual fuel oil is delivered to Puerto Rico by vessel. It is stored centrally at the former Commonwealth Oil Refinery complex on the south-west side of the island. From there, it is piped to the nearby Costa Sur plant and delivered by barge to the other three plants. Each of the three steam-electric plants has onsite storage for residual fuel oil. Palo Seco has capacity to store 450,000 barrels, San Juan 138,000 barrels, and Aguirre 780,000 barrels. Costa Sur has 800,000 barrels of storage that could be converted for other use. Based on 2013 generation Exhibits, this storage capacity represents approximately a 36-day supply for Palo Seco, 14 day supply for San Juan, and 40 day supply for Aguirre. The plants typically hold at least 15 days of fuel supply onsite.

7.1.2.2 Diesel (No. 2 Fuel Oil aka Distillate Fuel Oil)

Diesel is used at the combined-cycle units at Aguirre and San Juan and the combustion-turbine units at Cambalache, Mayagüez, and nine other small facilities around the island. Diesel fuel is delivered to storage facilities at Yabucoa and Bayamon and from there is barged to four larger stations (Aguirre, San Juan, Cambalache and Mayagüez). The nine other small facilities around the island operate infrequently and receive fuel deliveries by truck when required. The San Juan 2x200 MW combined cycle diesel-fired Units 5 and 6 have an attractive heat rate and could be converted to burn natural gas for a relatively modest investment of \$10-30 million. If San Juan natural gas delivery is established, it is likely that San Juan Units 7, 8, 9, and 10 could be replaced with more efficient units. The Yabucoa facility has storage capacity for four million barrels of crude oil, fuel oil, and refined products. The Bayamon facility has storage capacity for 3.5 million barrels. A 2013 report indicates that there are two diesel fuel transfer lines between the Palo Seco and San Juan plants that are in service. There is no information regarding onsite storage for diesel at any of the other plants.

7.1.2.3 Natural Gas

Natural gas is used at the privately-owned EcoEléctrica cogeneration facility and at the Costa Sur steam plant, which are both located at Guayanilla Bay on the southwestern coast where

the Peñuelas terminal and regasification facility is located. Natural gas is imported as LNG, mainly from Trinidad and Tobago (92% since 2010, under a 20-year contract for 0.5 MMtpa expiring in 2019, according to Energy Velocity). The EcoEléctrica plant is adjacent to the regasification facility and the Costa Sur plant receives gas via a short pipeline. The 2017 expansion of regasification facilities at EcoEléctrica LNG Import Terminal allows Costa Sur, which has dual-fuel units, to also be fully fired by LNG. As of May 2018, Costa Sur is now burning exclusively natural gas. There is a substantial take-or-pay gas contract in place that requires significant generation from Costa Sur.

Storage for one million barrels of LNG is available at the regasification facility. Based on the original FERC application, EcoEléctrica was approved to construct two, one-million-barrel (160,000 cubic meters) LNG storage tanks. However, the second storage tank was never constructed and FERC authorization to construct the second tank has lapsed. However, the space remains available to construct the second tank if needed. Prior to 2017, the facility had two spare regasifiers. In 2017, it obtained FERC approval to put one of them into continuous service and to increase total sendout capacity from the import terminal to 279 MMcf/d. This increased LNG cargo (ship) deliveries to 40 per year from 24 per year. The FERC approval of the third gasifier allowed the gas received by Costa Sur to double to 186 MMcf/d from 93 MMcf/d. The remaining spare (fourth) gasifier also has a capacity of 93 MMcf/d, which would increase total plant sendout to 372 MMcf/d if put into service. Some steps were taken prior to 2013 to convert some of the other steam plants to natural gas, but these were put on hold due to uncertain gas supply following the hurricanes and cancellation of a cross-island pipeline project. There are also pre-existing plans to build the Aguirre Offshore GasPort, a floating storage and regasification unit offshore near the Aguirre plant that would be operational no later than January 1, 2022 and to convert the Aguirre plant to natural gas.

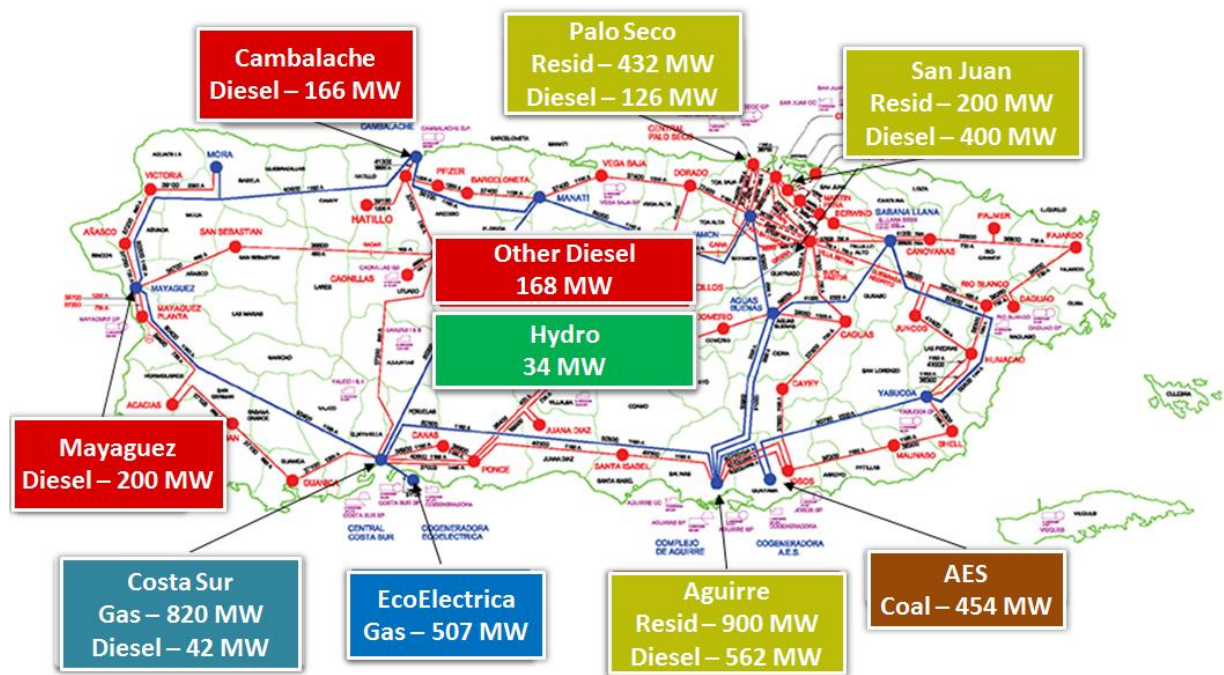
7.1.2.4 Coal

The privately-owned AES-Puerto Rico facility burns Colombian bituminous coal. The coal is delivered to Puerto Rico at the Las Mareas Port, just south of the plant site and is transported to the plant via covered conveyors. AES maintains a 30-day inactive coal storage supply to address potential delivery interruptions and a 20-day active storage supply.

7.1.2.5 Independent Power Production

IPP generation contributions to the island is contracted through 2022 for EcoEléctrica's 507 MW and 2027 for AES' 454 MW. Locations of the electric generating units in Puerto Rico are presented in Exhibit 7-3.

Exhibit 7-3. Current PREPA Generating Map



Source: PREPA, Siemens

7.1.2.6 Proposed Fuel Infrastructure and Natural Gas-Fired Generation Changes

Currently, only 22 percent of PREPA-owned generation is natural gas-fired. In the aftermath of the hurricanes, PREPA is considering options for new infrastructure, including the possibility to convert certain diesel or residual fuel oil units to natural gas. Such conversions would help to meet the requirements under the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) regulations as well as to take advantage of abundant and low-cost natural gas from the mainland. One such option is to convert San Juan Units 5 and 6, which represent 400 MW of relatively new (2008) and reliable baseload generation, from expensive diesel to cheaper natural gas in the form of LNG. The estimated total annual fuel requirements for these two units would be on the order of 24-25 Tbtu/yr., assuming a heat rate of 7,652 Btu/kWh and a capacity factor of 89-93%. To facilitate conversion, the San Juan plant would require a natural gas receiving, storage, and supply system.

In addition to possible natural gas-fired generation changes, PREPA is considering several fuel infrastructure options in its 2018 IRP. These options include the following, in no implied priority:

- Aguirre Offshore GasPort
- Ship-based LNG at San Juan with pipeline to Palo Seco
- Land-based LNG at San Juan with pipeline to Palo Seco
- Ship-based LNG at Mayagüez (west)
- Ship-based LNG at Yabucoa (east)

- LNG or compressed natural gas (CNG) delivery to San Juan and potentially Palo Seco
- Additional regasification capacity and new natural gas pipelines, first from EcoEléctrica LNG Import Terminal to Aguirre and then to San Juan
- No new gas infrastructure

This analysis reviews the many considerations surrounding these options without presupposing that any option is a required solution for supporting projected electricity demand or for compliance with any regulatory requirements. This section is followed by a section discussing these fuel infrastructure Scenarios and the issues and considerations reflecting each Scenario.

7.1.2.7 Aguirre Offshore GasPort

On April 17, 2013, Aguirre Offshore GasPort, LLC (Aguirre LLC), a wholly-owned subsidiary of Excelerate Energy, LP, filed an application with FERC to develop a floating offshore LNG regasification facility called Aguirre Offshore GasPort (AOGP) to supply natural gas to PREPA's existing Aguirre Power Complex in Salinas, Puerto Rico. The AOGP facility would consist of an offshore berthing platform, a floating storage and regasification unit (FSRU), and a 4-mile-long, 21-inch outside diameter subsea pipeline connecting to the Aguirre Power Complex. AOGP was being developed with cooperation between Excelerate Energy, LP and PREPA.

Under the Aguirre LLC application, the AOGP would provide LNG storage capacity and sustained deliverability of natural gas to the Aguirre plant. The AOGP facility would assist PREPA's plan to convert the Aguirre plant from a residual fuel oil- and diesel-only plant to a facility capable of burning diesel and natural gas for the combined cycle units and heavy fuel oil and natural gas for the thermoelectric plant. The AOGP facility would have LNG storage capacity of 3.2 Bcf (150,000 cubic meters) and a natural gas send out capacity of 500 MMcf/d (peaking deliverability of up to 600 MMcf/d) to the Aguirre plant. Based on data from Aguirre LLC, the estimated total construction period for AOGP facility was approximately 12 months, and total capital cost of AOGP facility was estimated (inflated to 2018\$) at \$403 million (including onshore and offshore components, permits, financing costs, etc.). This estimation does not include the capital cost related to fuel conversion of the Aguirre power plant which PREPA has estimated the annual fixed operating costs to be approximately \$81.5 million, excluding debt service.

The existing Aguirre units include 1,462 MW of diesel- and residual fuel oil-fired generation. If converted to natural gas, the expectation is that the maximum capacity of gas-fired generation would be 1,076 MW. The maximum daily volume of natural gas estimated to be required for this converted capacity would equal 155 MMcf/d. For the purpose of forecasting delivered natural gas prices to Aguirre, Siemens used an offtaker pricing formula similar to those used by large-scale Gulf Coast LNG offtakers in order to represent the estimated delivered cost to supply gas to Aguirre via AOGP. This pricing formula (*Price of Natural Gas* = $1.15 * \text{Henry Hub} + 4.35$), together with the average daily gas burn volume at an 80% generation capacity factor, gives a range from \$423 million to \$639 million in annual fuel supply costs each year of operation. This gives a starting point for estimating the required revenues the power generation plant would require supporting the capital, operating, and financing costs for AOGP.

PREPA commissioned a detailed economic analysis of the AOGP project using four resource plans and three price Scenarios³⁸. The analysis concluded that the AOGP base price Scenario (where the base price is derived from the U.S. Energy Information Administration's Annual Energy Outlook 2017) demonstrated the benefits of AOGP as compared to the No AOGP base price Scenario. The conclusion results from the AOGP base Scenario having lower overall system costs on the order of \$3.42 billion due to higher fuel costs incurred without AOGP. A similar benefit-cost analysis conclusion in favor of the AOGP project was reached when using a high oil price Scenario both with and without full Renewable Portfolio Standard (RPS) compliance. However, the AOGP low oil price Scenarios both with and without full RPS compliance were found to have a higher system cost than without the AOGP project. Based on these results, the economic analysis recommended proceeding with the AOGP project and associated Aguirre unit conversions.

Immediately following the second hurricane in September 2017, the Governor of Puerto Rico declared a state of emergency due to the devastation of Hurricane Maria. The widespread damage inflicted by Hurricane Maria, resulted in the Puerto Rico Energy Commission³⁹ (PREC) issuing an order⁴⁰ (dated April 26, 2018 for Case No. CEPR-AP-2017-0001) staying all proceedings to allow PREPA to focus on restoring electric service, including the proceeding on the AOGP project. Prior to this event, in early July 2017, PREPA's Fiscal Oversight and Management Board (FOMB) filed for protection under Title III of PROMESA. Later in July 2017, Excelerate Energy LP, the contractor for the AOGP project, announced that it had canceled its contracts with PREPA to construct the natural gas terminal. As a result of these events, PREC delayed any consideration of AOGP until such time as PREPA decides to pursue the project as part of its 2018 IRP. PREPA's March 2018 draft fiscal plan assumes AOGP is completed and Aguirre plants are converted to run on natural gas by January 1, 2022. If AOGP does not proceed, PREPA may consider other LNG supply options. In the meantime, residual fuel oil and diesel will continue to be primary fuels at Aguirre at a higher cost than for power generated using LNG.

A March 2017 Siemens PTI fuel delivery assessment⁴¹ analyzed the feasibility of containerized LNG or CNG to the Aguirre power station absent the AOGP project. The assessment found that containerized LNG deliveries would require 193 ISO containers per day while CNG deliveries would require 617 containers per day to meet project demand at the power plant. As a result, LNG delivery in ISO containers to Aguirre, absent AOGP, was determined to be impractical due to the expected gas demand and the amount of container handling required on a daily basis and vessel deliveries required on an annual basis.

As mentioned earlier, the IRP will consider other LNG options to bring natural gas to the island and the AOGP is not currently being studied as part of the core IRP. It remains Siemens view that the possible benefits to the AOGP project (together with upgrades to the Aguirre generating plant to use natural gas) include lower overall system costs compared to current infrastructure in either a base case price or a high oil price Scenario. The AOGP

³⁸ <http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1.02-Part-1-Economic-Analysis-Report.pdf>

³⁹ PREC is now known as the Puerto Rico Energy Bureau (PREB)

⁴⁰ <http://energia.pr.gov/wp-content/uploads/2018/04/Final-Resolution-and-Order-CEPR-AP-2017-0001.pdf>

⁴¹ <http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1-04-PREPA-Fuel-Delivery-Option-Assessment.pdf>

options brings the benefits of lower carbon emissions from the Aguirre generation plant by burning more natural gas compared to current emissions, greater flexibility and security in fuel supply options, the ability to repurpose AOGP infrastructure (the floating storage and regasification unit could be sold and moved), and the potential to increase PREPA-owned generation as IPP contracts roll off in 2022 and 2027. However, the AOGP option brings the risks of potential of sustained low-oil prices could render AOGP uneconomic, new fuel infrastructure that could be vulnerable to hurricanes, the possibility of a decreasing need for fossil generation as load decreases with further population out-migration or increases in energy efficiency and renewable energy penetration, and continued dependence on south-to-north electricity transmission to reach load centers on the north side of the Island.

PREPA has addressed some of the concerns raised by PREC following the last IRP filed in 2015. One such concern related to the overall economic benefit of AOGP, which was addressed in detail in the economic analysis mentioned previously⁴² and found to be generally favorable. In addition, the present IRP addresses a second concern, namely that PREPA must perform a comprehensive review of its options using a capacity expansion model that would test the AOGP against optimized portfolios that could achieve the same benefits as the AOGP with a different set of resources. However, PREPA still requires a clearly defined plan to obtaining all necessary permits as well as a potential partner to construct the AOGP. With Excelerate's cancellation of contracts in July 2017, PREPA would need to solicit renewed interest in the project from potential partners.

7.1.2.8 Ship-based LNG (or CNG) at San Juan with Possible Pipeline to Palo Seco

PREPA has studied a ship-based standard-scale LNG (and CNG) receiving terminal in the San Juan area, including a ship-based (offshore) option known as a floating storage and regasification unit (FSRU). A June 2015 Galway Energy Advisors natural gas study for PREPA's northern power plants (San Juan and Palo Seco) evaluated the feasibility and potential fatal flaws of an import facility sized to handle 125,000 MMBtu per day. The study looked at importing either LNG or CNG. Given the lack of CNG project examples in the U.S. and PREPA's preference for 1-2 deliveries per month to limit traffic in the already busy San Juan port, the fuel choice of the higher volume CNG was evaluated but was considered less viable than LNG supplied via standard scale LNG ships delivering 2.0-3.6 million MMBtu per ship.

The Galway study considered one ship-based (offshore) and three land-based (onshore) options with 14 configurations, including an LNG regasification barge, an LNG FSRU, an LNG floating storage unit (FSU) with onshore vaporization, LNG and CNG onshore storage and vaporization, and non-self-propelled vessels with onboard CNG storage. All of the four site options would require one or more pipelines to deliver vaporized LNG or depressurized CNG to the power plants. Several considerations were weighed for a ship-based LNG terminal. Concerns identified with this option included potential harm to environmentally sensitive zones where coral reefs, mangroves, sea grass beds, wetlands, critical wildlife areas, rivers and streams, karst areas, and aquifers exist. In addition, harbor view impacts were considered, wherein the visual impact on residents was assessed. In general, an FSRU would be sited approximately three miles offshore, but would need to be sited 13 miles or more offshore to be completely out of sight of harbor residents. A location 13 miles offshore

⁴² <http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1.02-Part-1-Economic-Analysis-Report.pdf>

would require a lengthy pipeline, with its own environmental risks and added costs, to bring supply to the plants. The analysis reached the conclusion that among the 14 options, the most feasible option would be land-based (onshore) LNG storage and vaporization at a warehouse site adjacent to the San Juan power station and with standard scale LNG carrier delivery directly to onshore tanks.

A separate 2018 study⁴³ evaluated the economics of land-based (onshore) LNG storage and vaporization and compared to FSRU receiving terminals through the assessment of analyses performed for Indonesia, an island nation best served by LNG. An FSRU terminal in Sorong, Indonesia was estimated to be \$0.6 million per MMcf/d in capital costs versus \$2.1 million per MMcf/d for a land-based option. The FSRU vs. land-based (onshore) LNG produced an internal rate of return (IRR) of 13.77% vs. -0.27%, respectively, with the principle difference in IRR due to the difference in the 3.5:1 capital cost ratio. The study affirmed the use of a \$4.35 per MMBtu transportation adder (liquefaction + transportation + margin) for LNG from the Gulf Coast, Trinidad & Tobago, or other nearby source. However, differences in volume and location-based costs exist between the Indonesian example and San Juan port, and this rule-of-thumb estimate predicts a lower capital cost estimate for the FSRU. A different 2017 study⁴⁴ estimated the cost for a new 30,000 m² LNG tanker at \$105 million, which is the Exhibit used in this analysis (together with an additional \$80 million in costs for regasification, jetty, piping, etc.). It is possible to reduce the capital cost for an FSRU by the utilization of a used LNG tanker, which could also reduce, by up to half, the time to implement the FSRU project. A September 2018 announcement by TEMA LNG Terminal Co Ltd⁴⁵ puts the cost of an estimated small-scale 20,000 m² FSU based in Ghana at \$350 million with an 18 month project timeframe. In any event, the FSRU option is expected to remain the lower cost option vs. land-based LNG to meet the fuel needs of San Juan and Palo Seco plants. The FSRU option comes with the added benefit that it could potentially be repurposed, and the terminal moved or sold to recover some of the initial capital investment.

New Fortress Energy proposed an offshore natural gas fuel supply option to provide San Juan and Palo Seco with LNG. The company has signed a 20-year deal to supply natural gas to Jamaica and could use the country as a hub to sell LNG to Puerto Rico. The intent of the New Fortress Energy proposal would provide for all-in fuel delivery to San Juan with optional included conversion of San Juan units 5 and 6. The delivered LNG price would be negotiated but there would be no long-term commitment or upfront capital cost commitment. The capital investment would be recovered through a calculated gas adder to the rate. Alternatively, Trinidad & Tobago is the primary supplier of LNG to Puerto Rico and since 2010 has shipped an average of 2.1 Bcf/month of natural gas to EcoEléctrica Inc. as well as additional LNG (since 2012) to Costa Sur via the same EcoEléctrica LNG Import Terminal.

⁴³ "An Economic Evaluation of Onshore and Floating Liquefied Natural Gas Receiving Terminals: the Case Study of Indonesia," Giranza and Bergmann (2018), <http://iopscience.iop.org/article/10.1088/1755-1315/150/1/012026/pdf>

⁴⁴ "Small Scale LNG: Emerging Technologies for Small-Scale Grids," Tony Regan, DataFusion Associates, http://esi.nus.edu.sg/docs/default-source/doc/small-scale-lng-esi-roundtable.pdf?sfvrsn=2&_sm_au=iVVVtq5FtZNFJDTM

⁴⁵ Jiangnan to build regas barge for Ghana's first LNG import project, Mike Corkhill, LNG Shipping World, https://www.lngworldshipping.com/news/view/jiangnan-to-build-regas-barge-for-ghanas-first-lng-import-project_54246.htm

Ship-based LNG delivery to the San Juan region with ship-based or onshore LNG storage and vaporization is a viable fuel infrastructure option for PREPA. However, the most likely Scenario is a medium-scale LNG ship (30,000 m³) rather than a large-scale LNG carrier (85,000 m³ to 170,000 m³ or more), which would require dredging large quantities of material from the San Juan harbor to create a channel suitable for the large-scale LNG carriers. The potential benefits of the option for medium-scale LNG carriers (with regasification either floating or land-based) include efficient delivery of cost-competitive bulk LNG with minimal impact from increased ship traffic, reduced carbon emissions by converting units at San Juan and Palo Seco to natural gas from residual fuel oil, and lower fuel costs compared to current infrastructure in either a base case price or a high oil price Scenario. Possible risks include a sustained low-oil price future rendering operating costs higher using natural gas than residual fuel oil, the creation of new fuel infrastructure that could be vulnerable to hurricanes, supply chain vulnerability preventing timely delivery of LNG, and the possibility of a decreasing need for fossil generation as load decreases with further population out-migration or as PREPA increases energy efficiency programs and renewable energy penetration.

Onshore LNG storage offers advantages and disadvantage compared to ship-based offshore storage (FSU) and/or regasification (FSRU) or regasification. The FSU and FSRU options would need to go through a permitting process with the Federal Energy Regulatory Commission (FERC), the U.S. EPA, the U.S. Department of Transportation Maritime Administration, the U.S. Coast Guard, local agencies in Puerto Rico, and would be subject to regulatory siting challenges resulting from large exclusion zones in the harbor. Furthermore, several existing statutes would need to be navigated, including the Natural Gas Act, the Clean Air Act, the Clean Water Act, the Deepwater Port Act, the National Environmental Policy Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Maritime Protection, Research, and Sanctuaries Act, the Resource Conservation and Recovery Act, the Rivers and Harbors Act, and others.⁴⁶ All offshore pipelines would require a subsea pipeline to both San Juan and Palo Seco power plants. By contrast, the onshore LNG storage option would be co-located by the San Juan plant with a connecting pipeline to Palo Seco. This onshore option would avoid some of the regulatory requirements mentioned above with the FSU and FSRU options but would be subject to its own regulatory challenges. The onshore LNG storage and FSU/FSRU options would likely be mutually exclusive due to land use and/or port lease issues as well as cost prohibitive due to duplicative infrastructure buildout.

A ship-based FSRU would occupy one of two berths directly in front of the San Juan steam plant. Based on an estimated 350 MW gas-fired capacity at San Juan, the maximum daily gas volume requirement would not exceed 50.4 MMcf/d. However, if a pipeline to the Palo Seco plant is included, adding an incremental 302 MW of gas-fired capacity at Palo Seco, the maximum daily gas volume requirement would increase to 93.6 MMcf/d. The extant remaining regasifier (93 MMcf/d send-out capacity) at the EcoEléctrica LNG Import Terminal could satisfy these needs if a pipeline were to be built from the import terminal to the north, either directly or routed via Aguirre.

⁴⁶ https://www.epa.gov/sites/production/files/2015-08/documents/lng_regulatory_roadmap.pdf

7.1.2.9 Land-based (onshore) LNG at San Juan with pipeline to Palo Seco

As mentioned previously, the Galway study reached the conclusion that among the 14 options, the most feasible is land-based (onshore) LNG storage and vaporization at a warehouse site adjacent to San Juan power station on its east side and with standards scale LNG carrier delivery directly to onshore tanks. The best option considered was immediately adjacent to San Juan plant in a warehouse district to the east. A second viable option for an onshore storage and vaporization system was considered further to the east of San Juan plant at a location known as Pier 15/16. However, Siemens notes that an onshore facility is likely to be costlier than an FSRU or FSU option. Furthermore, the Galway study did not consider small- to medium-scale LNG carriers as a possible supply option for direct delivery into San Juan harbor. Instead the Galway study considered smaller-scale shuttle tankers being loaded from LNG ships via ship-to-ship transfer in the area of Guayanilla Canyon on the protected south side of Puerto Rico).

Looking at the generation plants that an onshore LNG terminal would supply, it is expected that current generating units using residual fuel oil at San Juan and Palo Seco will be replaced, retired or limited in use in several years to achieve MATS compliance. The replacement generation for these sites will be capable of natural gas and diesel firing. A northern LNG terminal could provide significant cost savings relative to diesel fuel. Based on input from PREPA, a land-based (onshore) LNG terminal at San Juan would require an estimated \$492 million in capital costs (2018\$) including \$457 million for the LNG terminal and \$35 million for the pipeline from San Juan to Palo Seco. Note that the pipeline costs are lower than in the 2015 IRP due to the assumed use of an existing oil pipeline right-of-way to construct the 4.2 mile pipeline to Palo Seco. Annual fixed operating costs (OPEX) are conservatively assumed to be 5.2% of total capital expenditures (CAPEX), whereas the general rule of thumb for OPEX is 2.5%-3% of CAPEX. The earliest online date would be July 1, 2022.

7.1.2.10 Ship-Based LNG to Mayagüez (west) and/or Yabucoa (east)

Mayagüez is located on the western side of the island, where PREPA has a 4x50 MW (total of 200 MW) diesel-fired generation. Yabucoa is located on the eastern side of the island, where PREPA has two combustion turbines (2x21 MW) also burning diesel. Siemens is investigating the possibility of one or more floating LNG and storage import terminals that could service the power generation plants at Mayagüez, Yabucoa, or both locations. The existing generation could be complemented with up to 302 MW of gas-fired generation, which would require a natural gas fuel supply solution. The proposed solution would most likely be a ship-based (offshore) FSRU option, similar to what could be installed in the San Juan port for LNG supply to San Juan plant and/or Palo Seco plant and with similar capital expenditure and operating expenditure estimates. Accordingly, Siemens estimates the CAPEX for ship-based LNG delivery to Mayagüez and/or Yabucoa to be \$185 million and the annual OPEX to be \$9.6 million.

7.1.2.11 LNG/CNG Delivery via ISO Containers to Northern Power Plants

Alternatively, natural gas supply to the northern side of the island could be delivered in the form of LNG or CNG using ISO containers. This mode of LNG or CNG transport uses standard, intermodal, 40 foot ISO containers that can be marine-shipped, trucked, handled, and stored much like a standard 40 foot cargo container. Each 40 foot LNG ISO container is an independent storage system with about an 858 MMBtu capacity for up to a 90 day storage period. Each 40 foot CNG ISO container has a capacity of about 267 MMBtu.

There are numerous LNG and CNG suppliers available in the U.S. and internationally that utilize these systems. LNG and CNG ISO containers potentially could be delivered to the San Juan port and unloaded using standard container handling equipment, trucked to San Juan / Palo Seco sites using existing container tractor-trailers, and then directly connected to a common regasification system feeding the fuel delivery piping of individual units. While this delivery method is generally more costly than bulk supply for large volumes of LNG, it could be a cost-effective option to fuel the new small CCs at Palo Seco. In addition, the LNG or CNG ISO containers could provide an interim solution that could deliver fuel to the San Juan Units 5 and 6 CCs while long-term delivery infrastructure is being permitted and constructed.

The San Juan port that is directly adjacent to the San Juan power plant has a large capacity container terminal that could potentially support daily full and empty LNG container movements. About 50 of these containers per day could be loaded onto trucks for transport to Palo Seco, with empty containers carried back on the return trip. LNG or CNG containers⁴⁷ also could be used to deliver natural gas to peaking sites such as Cambalache and Mayagüez. The practicality of delivering the large volume of LNG or especially CNG required for both Palo Seco CCs and San Juan CCs has been assessed.

The same March 2017 Siemens PTI fuel delivery assessment further developed this analysis of LNG / CNG to northern power plants and separately to Aguirre, estimating that containerized LNG deliveries would require 40 ISO containers per day while CNG deliveries would require 126 containers per day to meet project demand at the two northern power plants (for Aguirre, it would be 193 and 617 containers, respectively). As a result, the study concluded that small-scale LNG / CNG delivery either as a bridge fuel or long-term solution is not feasible given that small-scale LNG / CNG delivery costs to San Juan are prohibitively high and operational risks are too great. The study recommended further evaluation of bulk LNG delivery to San Juan and Palo Seco with onsite tank storage (the same conclusion as the previously cited Galway study). Siemens does not recommend small-scale LNG or CNG delivered via ISO containers as a viable solution for this IRP.

7.1.2.12 Pipeline Supply from EcoEléctrica LNG Import Terminal

An alternative to a northern LNG / CNG terminal and potentially also to the AOGP could be a natural gas pipeline that delivers natural gas from the existing EcoEléctrica LNG Import Terminal to the San Juan and Palo Seco plants in San Juan. Such a pipeline could be constructed to have one segment along the southern coast of Puerto Rico to serve the Aguirre power plant (creating an alternative to the AOGP plant) before a second segment turns north toward the San Juan plant with a lateral to Palo Seco. Alternatively, a pipeline could be routed to go directly from the EcoEléctrica LNG Import Terminal to San Juan, which would not require additional regasification apart from bringing online the extant remaining gasifier. Any such project must consider the pipelines costs as well as permitting feasibility.

A past 2008n proposal to bring natural gas to the north (Gasoducto del Norte or GdN, also known as Via Verde) by pipeline from EcoEléctrica LNG Import Terminal encountered significant public opposition during permitting and was canceled. Several pipeline routes were

⁴⁷ LNG tank trailers also can be used to transport LNG. With necessary permitting and commercial arrangements, trailer loading facilities could be located at any site with bulk LNG storage, such as EcoEléctrica, or at an onshore LNG terminal at San Juan.

considered but the option designated as preferred was generally north from EcoEléctrica to Arecibo and then east to Palo Seco/San Juan. Laterals were considered to serve the Cambalache and Mayagüez peaking units. A South-North pipeline from Aguirre to San Juan area could be more practical than the preferred western routes considered earlier. A natural gas pipeline between Costa Sur and Aguirre has been attempted in the past (Gasoducto del Sur) and is technically feasible. Section 2.6.1 of the 2008 GdN study referenced above identified two possible routes from Aguirre to the north. These routes' lengths were about 50 miles each, with about 600 acres of right-of-way including up to 64 acres of wetlands impact. One of these routes is close to an already-disturbed corridor for Route 52 and had the lower wetlands impact. A pipeline route along the south coast, from Costa Sur to Aguirre, generally is perceived as more practical and having less environmental and public impact than a pipeline along the northern coast. This portion of a system to transport natural gas from EcoEléctrica to the north may be less controversial than the South-North section.

The 2008 GdN report provided estimated costs for such a pipeline, confirmed by more recent estimates performed by Siemens. The Aguirre-San Juan overland route (not the route along Route 52) was about 52 miles long before adjustment for terrain. A 20 inch pipeline size was assumed for a flow volume of 249 MMcf/d. Costs included route surveying, engineering, project management, inspection, materials, construction and restoration. The cost of this line in mid-2008 U.S. dollars was \$206 million, or \$238 million in 2018 dollars. This comports well with Siemens' current estimate of a cost of \$221 million for this South-North pipeline route, although Siemens estimated that a 16" pipe is sufficient to supply the combined 93.6 MMcf/d demand from San Juan and Palo Seco after conversion to natural gas. Other assumptions used by Siemens include a distance of 49 miles and \$4.5 million per mile (2018\$). Considering that a south coast pipeline (Costa Sur to Aguirre) has been budgeted in the past, PREPA should have reasonably accurate estimates of cost. The pipeline nominal length from Costa Sur to Aguirre is 42 miles. Using a cost of about \$5.1 million per mile (2018\$) for 20" pipeline, which would carry 249 MMcf/d or sufficient gas volumes to supply Aguirre, San Juan and Palo Seco, this would cost approximately \$214 million. The total cost for a pipeline from EcoEléctrica LNG Import Terminal to Aguirre to San Juan is estimated to be \$470 million, including \$35 million for a short 4.2 mile pipeline to the Palo Seco plant.

Although a pipeline route has been attempted in the past, but was halted due to public opposition, the aftermath of the storms represents an important inflection point in Puerto Rico's history. There is a potential window of opportunity to re-evaluate the pipeline option during this time of rebuilding. It is recommended that an updated cost and routing analysis be conducted on possible pipeline supply options to Aguirre and San Juan/Palo Seco.

7.1.2.13 Alternative Fuels

PREPA received an unsolicited proposal from Puma Energy Caribe (Puma) and Aggreko in August 2017, which was approved for further consideration in October 2017. The proposal was for a 100 MW power generation solution using LPG (liquefied petroleum gas, which is mostly propane) in Bayamón, Puerto Rico (just outside of San Juan). The proposal would satisfy several important criteria that PREPA is looking for in power generation solutions, including a location in the north near load centers, a public/private partnership (P3) that would require no capital expenditure from PREPA and conforms to PREPA's Fiscal Plan Part VII (Investment Program) requiring that P3 generation in year 2026 be approximately 30% of the total system generation, and a turnkey approach that can be implemented quickly. The proposed solution would also have a relatively low heat rate (8,900 Btu/kWh) to provide efficient power generation, burn relatively clean LPG fuel to help meet MATS standards (and

which is typically cheaper than diesel or residual fuel oil), have a fast start time of two minutes to 100% capacity, and be strategically located near existing Puma facilities where no additional LPG storage would be needed beyond the existing 100,000 barrels of LPG storage.

Siemens believes that LPG fuel will remain cost-competitive compared to diesel and residual fuel oil. This aspect, together with the other attributed enumerated above, lead to the conclusion that this project is worthy of further exploration as one solution among many to develop new sources of power generation. The PUMA proposal that Siemens reviewed did not include a pricing formula or forecast, so an LPG price forecast was developed using the historical price relationship with crude oil. This forecast is provided in the following forecast section.

A coal price forecast is also provided for fuel supply costs to the AES plant, based on Siemens' 2018 spring outlook and benchmarked to the EIA AEO 2018 forecast and others.

7.1.2.14 No New Natural Gas Infrastructure

If additional natural gas infrastructure and supplies cannot be developed, one option is to maintain the status quo. This option ignores the potential fuel cost savings that could come from natural gas supply and may also increase the challenges with meeting MATS requirements. This option should also be considered in the IRP planning process, pending the available generation options review.

Other potential liquid fuels such as propane, ethane and biofuels could be considered. Over the past two years, propane has been about 2.5 times as costly as natural gas on an equivalent MMBtu basis. Propane when burned for power generation emits about 16% more carbon dioxide than natural gas but is cleaner than residual fuel oil. While increases in propane and ethane production associated with U.S. shale gas production have led to recent market imbalances that have depressed the prices of these products, prices have begun to rise again as the market recovers. Siemens believes that in the long-term, propane and ethane prices will maintain higher levels relative to diesel and certainly with respect to natural gas. So, while there may be some interim opportunities to take advantage of such fuels, propane, ethane, and biofuels are not expected to be long-term cost-effective solutions.

7.1.2.15 Fuel Infrastructure Scenarios Comparison

As discussed previously, there are a broad range of fuel infrastructure Scenarios. These include the following, in no particular order:

- Aguirre Offshore Gas Port (AOGP)
- Land-based (onshore) LNG to the North
- Ship-based (offshore) LNG to the North
- Ship-based (offshore) LNG at Mayagüez (west)
- Ship-based (offshore) LNG at Yabucoa (east)
- Small-scale LNG and CNG to the North and South
- Additional Regasification Capacity at EcoEléctrica LNG Import Terminal with a Costa Sur-Aguirre-San Juan Pipeline
- No New Gas Infrastructure

Each fuel infrastructure Scenario should be evaluated, at a minimum, on the broad categories of capital cost requirements, estimated operational costs, resiliency and reliability, environmental impact, and public concerns. Many other considerations are embedded within these categories, including technical complexity, permitting process, fuel supply options, regulatory compliance, commercial partnerships, etc. The following table provides a summary evaluation of these infrastructure options.

Exhibit 7-4. Fuel Infrastructure Options Assessment

Infrastructure Option	CAPEX (\$MM) (2018\$)	Annual OPEX (\$MM) (2018\$)	Max Daily Gas Volume (MMcf/d)	Max Capacity (MW)	Annualized CAPEX (\$/kW) (2018\$)	Annual OPEX (\$/kW) (2018\$)
Aguirre Offshore GasPort	GasPort=\$403 - Annual O&M=\$81.5 (+fuel)	(1,076 MW) - (7,500 Btu/kWh) - 155 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to AOGP or south-to-north power transmission.	Carbon and other emissions would be reduced with AOGP and conversion at Aguirre to gas-fired generation.	Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant.	N/A
Ship-based LNG (FSRU) at San Juan Port with pipeline to both plants	FSRU=\$185 - Pipeline to Palo Seco=\$35 - Annual O&M=\$11.4 (+fuel)	(650 MW) - (7,500 Btu/kWh) - 93.6 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU.	Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life.	Harborview would be impacted by FSRU and potential damage to marine environment from pipeline.	N/A
Ship-based LNG at Mayagüez (west)	FSRU=\$185 - Annual O&M=\$9.6 (+fuel)	(300 MW) - (7,500 Btu/kWh) - 43.2 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU.	Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life.	Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant.	N/A
Ship-based LNG at Yabucoa (east)	FSRU=\$185 - Annual O&M=\$9.6 (+fuel)	(300 MW) - (7,500 Btu/kWh) - 43.2 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU.	Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life.	Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant.	N/A

Assumptions and Forecasts

Infrastructure Option	CAPEX (\$MM) (2018\$)	Annual OPEX (\$MM) (2018\$)	Max Daily Gas Volume (MMcf/d)	Max Capacity (MW)	Annualized CAPEX (\$/kW) (2018\$)	Annual OPEX (\$/kW) (2018\$)
Small-scale LNG (or CNG) Solutions at San Juan Port and/or Aguirre	CAPEX=\$540 - Annual O&M=\$45-81	50-249 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to small-scale LNG port.	Carbon and other emissions would be reduced with LNG. Increased vessel traffic could impact coastal marine life.	Concerns over significantly increased vessel traffic in busy ports and potential damage to marine environment.	Unfeasible logistics for large volume customers
Land-based LNG at San Juan Port with pipeline to Palo Seco	Onshore LNG Terminal=\$457 - Pipeline=\$35 - Annual O&M=\$25.6	93.6 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to onshore LNG port.	Carbon and other emissions would be reduced with LNG. Increased vessel traffic could impact coastal marine life.	Concerns over significantly increased vessel traffic, disruptive pipeline to Palo Seco.	N/A
Pipeline from Costa Sur to Aguirre and San Juan (with additional regasification at EcoEléctrica)	Costa Sur to Aguirre Pipe=\$184 - Aguirre to San Juan Pipe=\$238 - Annual O&M=\$40	249 MMcf/d	Resiliency and reliability increased by transport via underground pipeline, providing flexibility to burn gas or diesel at converted generation plants. Additional regas capacity provided by private co.	Carbon and other emissions would be reduced with pipeline gas delivery and conversion to gas-fired generation.	Previous attempt to construct Costa Sur to San Juan pipeline was cancelled due to public concerns.	N/A
No New Gas Infrastructure	N/A	N/A	Existing generation plants lack flexibility in cleaner fuel choice. Onsite fuel storage more reliable than LNG deliveries susceptible to disruption.	Carbon and other emissions would remain higher than permissible/desired under current regulations.	Leaves space for increased renewables penetration and removes risk of stranded fossil fuel assets.	N/A

Source: Siemens, PREPA.

For the purposes of this 2018 IRP, there are four key fuel infrastructure options under consideration, which include:

- The land-based LNG at San Juan Port with pipeline to Palo Seco
- The ship-based LNG at Mayagüez (west),
- The ship-based LNG at Yabucoa (east), and
- The ship-based LNG (FSRU) at San Juan Port (supply to San Juan only).

Exhibit 7-5 below provides a summary view of these four infrastructure options together with CAPEX (2018\$MM), annual OPEX (2018\$MM), maximum daily gas volumes (MMcf/d), maximum generation capacity (MW), CAPEX in \$/kW, and annual OPEX in \$/kW.

Exhibit 7-5. Fuel Infrastructure Options Assessment

Infrastructure Option	CAPEX (\$MM) (2018\$)	Annual OPEX (\$MM) (2018\$)	Max Daily Gas Volume (MMcf/d)	Max Capacity (MW)	Annualized CAPEX (\$/kW) (2018\$)	Annual OPEX (\$/kW) (2018\$)	CAPEX + Annual OPEX (\$/kW) (2018\$)
Land-based LNG at San Juan Port with pipeline to Palo Seco	\$492	\$25.6	93.6	650	\$77	\$39	\$116
Ship-based LNG at Mayagüez (west)	\$185	\$9.6	43.2	300	\$63	\$32	\$95
Ship-based LNG at Yabucoa (east)	\$185	\$9.6	43.2	300	\$63	\$32	\$95
Ship-based LNG (FSRU) at San Juan Port (supply to San Juan only)	\$185	\$9.6	50.4	350	\$54	\$27	\$81

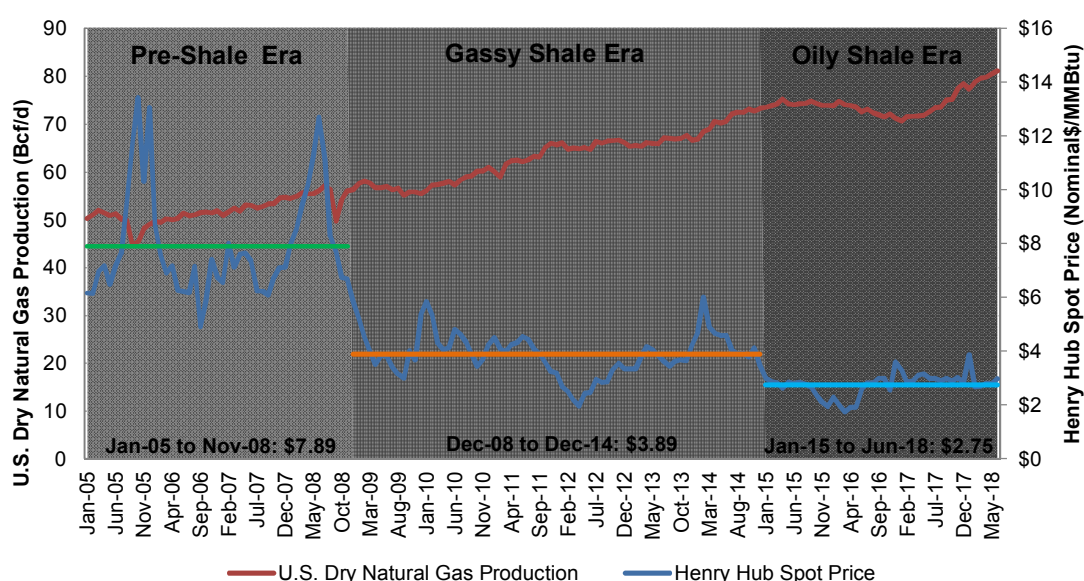
Apart from the No New Gas Infrastructure Scenario, the ship-based LNG (FSRU) at San Juan Port Scenario represents the lowest CAPEX and annual OPEX cost. The three feasible LNG to the North Scenarios (ship-based LNG, land-based LNG, and pipeline) would support the conversion of the northern plants of San Juan and Palo Seco (currently 1,158 MW) to natural gas, but with very different CAPEX costs depending upon the infrastructure. Ship-based LNG (FSRU) would be the least-cost, followed by pipeline supply from the south, followed by land-based LNG. The Costa Sur to Aguirre to San Juan Pipeline Scenario envisions the broader conversion to natural gas of generation plants at Aguirre, San Juan, and Palo Seco with commensurate benefits in terms of lower emissions and lower fuel costs than existing generation. The pipeline Scenario would also require upgrades to the EcoEléctrica LNG Import Terminal to supply sufficient fuel to meet this increased demand, but the costs would be borne by the private EcoEléctrica company. Each of these fuel infrastructure Scenarios bears merit and also has drawbacks that must be weighed in the context of the larger IRP study. Accordingly, a recommendation for pursuing one of these Scenarios is reserved pending the completion of the comprehensive review of PREPA's options using a capacity expansion model that would assess the convenience of installing natural gas generation or converting exiting units as is the case of San Juan 5 & 6 against optimized portfolios that could achieve similar benefits with different sets of resources.

7.2 Fuel Price Forecasts

Siemens prepared fuel price forecasts for natural gas at the Henry Hub, crude oil (West Texas Intermediate or WTI), and the oil-derivate products of diesel (No. 2 fuel oil) and residual fuel oil (No. 6 fuel oil with 0.5% sulfur). The Henry Hub benchmark is located in Erath, LA while the WTI benchmark is located in Cushing, OK. The diesel and residual fuel oil forecasts are based on New York Harbor pricing (per the contract terms for Costa Sur). The following sections describe the methodology for preparing these commodity forecasts for the 2018 IRP. Although standard scale LNG deliveries from the mainland U.S. would be difficult under the restrictions of the Jones Act, the following forecasts nevertheless are based on Henry Hub pricing to align with current fuel supply contract terms.

In accordance with the recommendation of the Transformation Advisory Council (TAC), which advocated for the use of a 10-year implied market volatility assumption for oil and natural gas in lieu of the 3-year volatility assumptions used in Siemens' original stochastic price simulations, Siemens has taken into consideration the recommendation for oil price volatility. However, for natural gas price volatility, Siemens feels there is justification for a shorter historical lookback. The pricing graph in Exhibit 7-6 shows how natural gas prices have declined in each of two different shale eras. Price volatility has also declined along with absolute prices. A potential return to higher price oil, which 2018 experienced for nearly the whole year, would help to increase associated gas production and keep additional downward price pressure on natural gas.

Exhibit 7-6. Pricing Eras of the Shale Revolution



Sources: Siemens, EIA.

By contrast with natural gas, which is still a regional market, oil is much more a global commodity and its price and volatility have been less affected by U.S. oil shale production than U.S. shale gas. This is an argument for a longer historical lookback when calculating the implied market volatility of oil, so Siemens took the TAC recommendation and recalculated the price distributions using a 10-year implied market volatility assumption. This allowed for the comparison of the 10-year, 5-year, and 3-year implied market volatility, which are 2.04%, 1.85%, and 1.83%, respectively. The result of the 10-year update was a higher short-term outlook but relatively unchanged long-term outlook at the one standard deviation level (84.1st percentile band). Although it is exceedingly rare as a Scenario, Siemens uses the two standard deviation level (97.7th percentile band) as a high oil price boundary case, which represents a future in which in only 23 out of 1,000 cases will have higher oil prices. This would see oil prices reach \$190/bbl in nominal dollars by the end of the forecast.

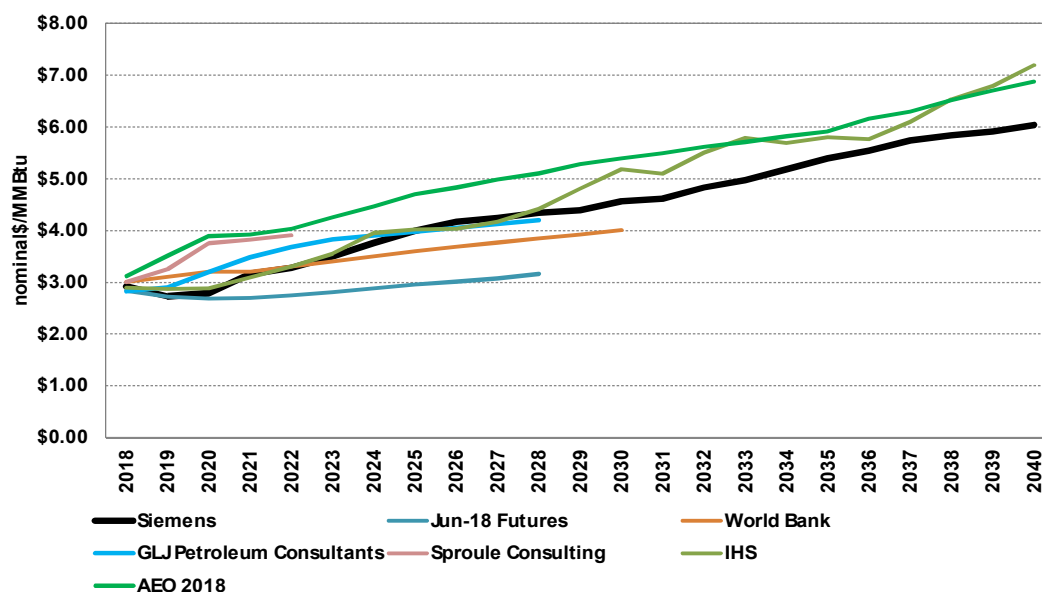
7.2.1 Henry Hub Natural Gas

Siemens develops an independent projection of regional fuel prices, in particular natural gas, crude oil and its derivative products (diesel, fuel oil, LPG, etc.). The natural gas price projections are developed using the GPCM® tool, is described in more detail in the

Attachment A, includes the benchmark Henry Hub price hub as well as more than 60 liquid trading hubs across North America. Siemens's Henry Hub forecast incorporates updated assumptions for natural gas demand, supply, and infrastructure and also benchmarks its short-term natural gas forecast to recent market forwards. Forwards are dated from June 2018. These forwards were used explicitly for the first 18 months of the forecast (June-2018 to Nov-2019), then blended into the fundamental forecast over the following 18 months. The first three years of the forwards curve represent the most liquid part of the curve, when trades and volumes are significantly higher than afterward. Exhibit 7-7 below provides a comparison of Siemens' forecast for Henry Hub prices with the AEO 2018 Henry Hub forecast as well as several other forecasts, for reference.

Exhibit 7-7. Henry Hub Forecast Comparison (nominal\$/MMBtu)

Forecaster	Siemens	AEO 2018	Jun-18 Futures	World Bank	GLJ Petroleum Consultants	Sproule Consulting	IHS
Unit	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu
Date	Jun-18	Feb-18	Jun-18	Apr-18	Apr-18	May-18	Feb-18
2018	2.91	3.11	2.84	3.00	2.82	3.00	2.89
2019	2.72	3.51	2.72	3.10	2.90	3.25	2.87
2020	2.79	3.89	2.68	3.20	3.20	3.75	2.88
2021	3.16	3.92	2.69	3.20	3.48	3.82	3.09
2022	3.27	4.03	2.74	3.30	3.67	3.90	3.30
2023	3.49	4.25	2.81	3.40	3.82		3.55
2024	3.76	4.46	2.88	3.50	3.90		3.95
2025	3.98	4.69	2.95	3.60	3.97		4.01
2026	4.16	4.83	3.01	3.68	4.04		4.03
2027	4.24	4.98	3.07	3.76	4.12		4.16
2028	4.34	5.10	3.16	3.84	4.20		4.41
2029	4.39	5.28		3.92			4.80
2030	4.56	5.39		4.00			5.18
2031	4.61	5.49					5.09
2032	4.82	5.61					5.50
2033	4.97	5.71					5.78
2034	5.18	5.81					5.69
2035	5.39	5.91					5.79
2036	5.54	6.15					5.76
2037	5.74	6.29					6.09
2038	5.84	6.51					6.53
2039	5.90	6.70					6.79
2040	6.03	6.87					7.19



Source: Siemens, various sources.

Siemens prepared a delivered natural gas price forecast for the Costa Sur, San Juan, and Aguirre generation plants, as well as the Mayagüez and Yabucoa plants, each of which can or could receive natural gas as a fuel supply and which represent the four sides of the island. In the case of Costa Sur, which is currently under a fuel supply contract⁴⁸, the adders are already known and applied to derive a delivered natural gas forecast price. In the case of Aguirre and San Juan, the P2 pricing formula from the San Juan fuel supply contract was used, which is equal to 115% of Henry Hub plus \$5.95/MMBtu. The Mayagüez and Yabucoa plants are assumed to have a similar LNG price structure as San Juan.

7.2.2 EIA Annual Energy Outlook 2018

The U.S. Department of Energy's (DOE) EIA Annual Energy Outlook (AEO) 2018⁴⁹, issued February 2018, provides their latest forecast for natural gas prices at the benchmark Henry Hub based on the key fundamentals of supply, demand, and infrastructure. The AEO 2018 Reference case forecasts that natural gas production growth will outpace consumption growth in every year to the forecast horizon of 2050. This driver, together with an estimated increase in lower-cost resources in the Permian and Appalachian basins, has resulted in Henry Hub prices that are 14% lower this year than last year's AEO. In the Permian basin, associated natural gas production from tight oil production is supported by relatively high oil prices. In the Appalachian basin, the Marcellus and Utica plays (located in Pennsylvania, Ohio, and West Virginia) continue to drive most U.S. production growth as they have over the last several years due to the substantial resource in-place with low production costs proximate to key demand centers in the U.S. Northeast. On the demand side, industrial and power generation demand together drive natural gas consumption growth to 2050. Growth in

⁴⁸ <http://energia.pr.gov/wp-content/uploads/2018/08/Memorial-Explicativo-R-del-S-219-CEPR.pdf>

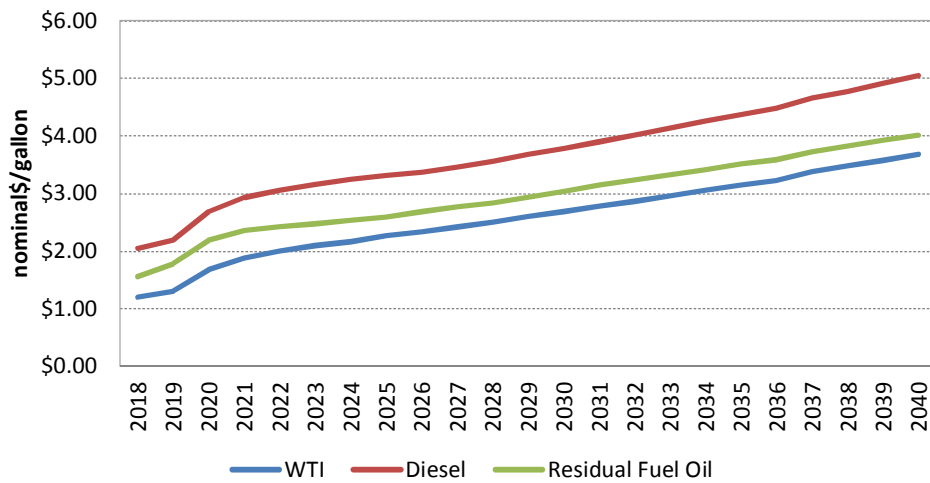
⁴⁹ <https://www.eia.gov/outlooks/aeo/>

exports via liquefied natural gas (LNG) facilities is strong through 2030 and pipeline exports to Mexico through 2025.

The AEO 2018 forecast for WTI, distillate fuel oil (diesel), and residual fuel oil is provided in Exhibit 7-8 below.

Exhibit 7-8. AEO 2018 Price Outlook (nominal\$/gallon)

Product	WTI	Diesel	RFO
Unit	nom\$/gallon	nom\$/gallon	nom\$/gallon
2018	1.20	2.05	1.56
2019	1.30	2.19	1.78
2020	1.68	2.68	2.18
2021	1.88	2.93	2.36
2022	2.00	3.05	2.42
2023	2.09	3.15	2.47
2024	2.16	3.24	2.53
2025	2.26	3.31	2.59
2026	2.33	3.37	2.68
2027	2.42	3.46	2.77
2028	2.50	3.55	2.83
2029	2.60	3.68	2.93
2030	2.68	3.77	3.03
2031	2.77	3.89	3.14
2032	2.86	4.00	3.23
2033	2.96	4.13	3.32
2034	3.05	4.26	3.41
2035	3.15	4.36	3.51
2036	3.23	4.47	3.58
2037	3.37	4.66	3.72
2038	3.48	4.76	3.81
2039	3.57	4.90	3.92
2040	3.68	5.04	4.01



Source: EIA

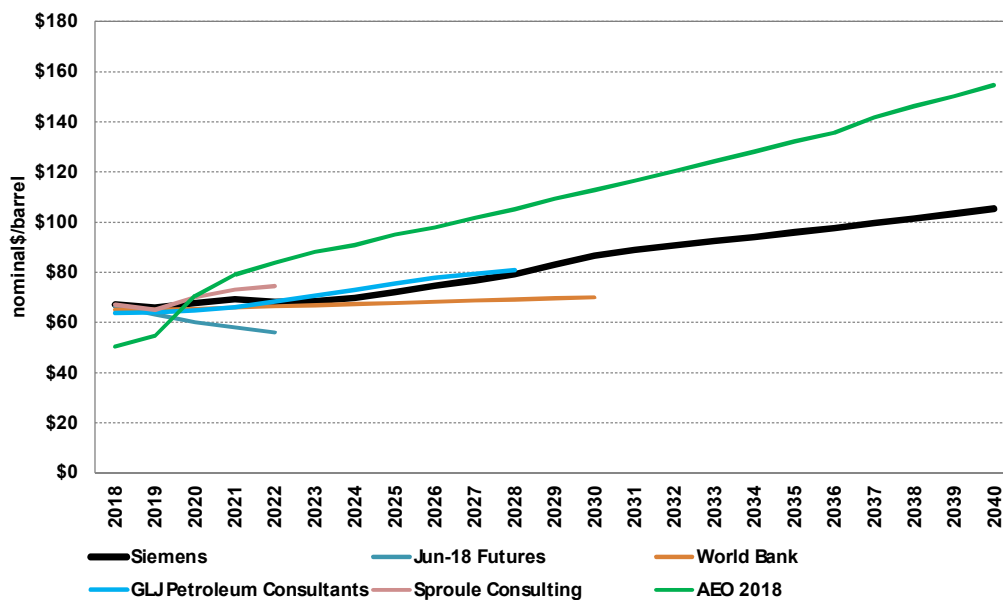
7.2.3 West Texas Intermediate (WTI) Crude Oil

Benchmark WTI oil price forecasts are developed exogenously by comparing and averaging price outlooks from a variety of reputable sources (EIA, IEA, etc.). A comparison of Siemens's WTI price outlook together with other outlooks is compiled in Exhibit 7-9.

Exhibit 7-9. WTI Forecast Comparison (nominal\$/barrel)

Forecaster	Siemens	AEO 2018	Jun-18 Futures	World Bank	GLJ Petroleum Consultants	Sproule Consulting
Unit	nom\$/barrel	nom\$/barrel	nom\$/barrel	nom\$/barrel	nom\$/barrel	nom\$/barrel
Date	Jun-18	Feb-18	Jun-18	Apr-18	Apr-18	May-18
2018	67.02	50.31	66.31	65.00	63.67	67.00
2019	65.82	54.67	63.16	65.00	63.86	65.00
2020	67.65	70.48	59.99	65.40	64.69	70.00
2021	69.10	78.98	57.93	65.90	65.99	73.00
2022	68.20	83.85	55.98	66.30	68.33	74.46
2023	68.49	87.97		66.80	70.62	
2024	69.61	90.78		67.20	73.01	
2025	71.94	94.96		67.70	75.38	
2026	74.57	97.80		68.16	77.79	
2027	76.65	101.57		68.62	79.31	
2028	79.05	105.06		69.08	80.77	
2029	82.86	109.30		69.54		
2030	86.65	112.70		70.00		

Forecaster	Siemens	AEO 2018	Jun-18 Futures	World Bank	GLJ Petroleum Consultants	Sproule Consulting
Unit	nom\$/barrel	nom\$/barrel	nom\$/barrel	nom\$/barrel	nom\$/barrel	nom\$/barrel
Date	Jun-18	Feb-18	Jun-18	Apr-18	Apr-18	May-18
2031	88.89	116.46				
2032	90.59	120.22				
2033	92.30	124.19				
2034	94.02	128.00				
2035	95.79	132.13				
2036	97.56	135.49				
2037	99.41	141.64				
2038	101.40	146.12				
2039	103.31	150.07				
2040	105.28	154.52				



Source: Siemens, various sources.

7.2.4 Columbia Coal

Coal sourced from Columbia is forecasted based on Siemens' 2018 spring outlook for Illinois Basin (ILB) coal together with the historical relationship of Columbia coal prices to ILB coal prices. Note that the Exhibits below do not include a flat \$10/ton adder for transportation, but this is added to the delivered fuel price for the AES plant that can be found below.

**Exhibit 7-10 Columbia Coal Mine Mouth Price Forecast
(nominal\$/ton)**

Unit	nom\$/ ton
Date	Jul-18
2018	69.43
2019	62.24
2020	58.76
2021	59.02
2022	58.02
2023	58.41
2024	57.69
2025	58.51
2026	59.61
2027	60.73
2028	61.88
2029	63.05
2030	64.24
2031	65.46
2032	66.69
2033	67.95
2034	69.24
2035	70.55
2036	71.89
2037	73.28
2038	74.71
2039	76.17
2040	77.66

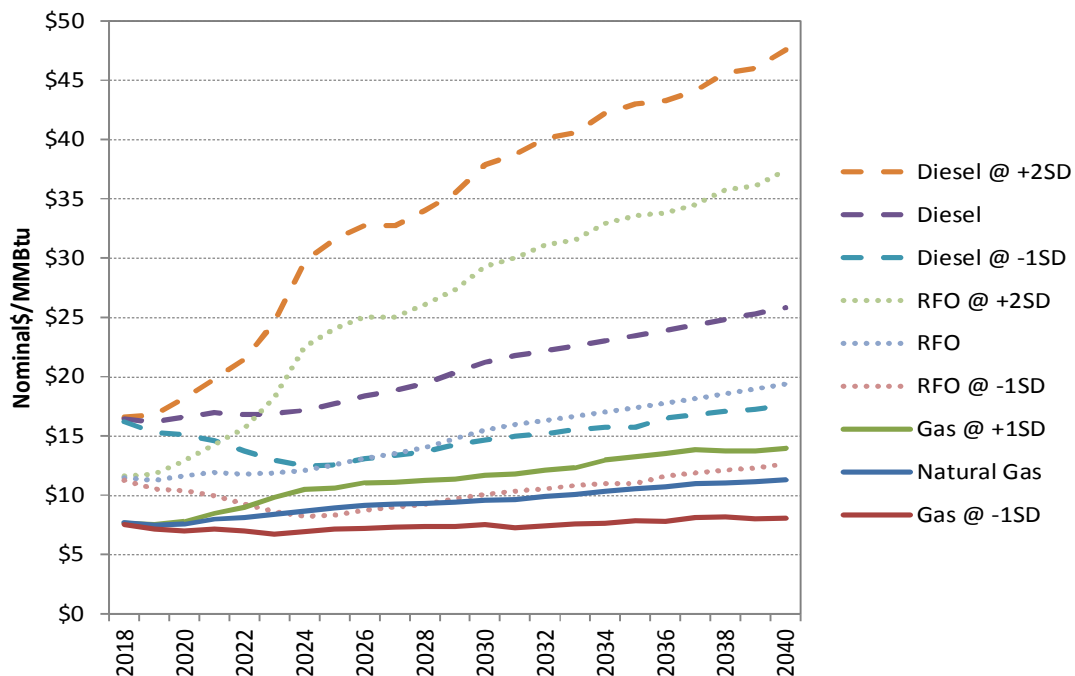
7.2.5 Forecast Delivered Fuel Prices at Key Power Plants

The tables below provide Siemens' outlook for delivered fuel prices to the four sides of Puerto Rico (Aguirre, San Juan / Palo Seco, Costa Sur, EcoEléctrica, Mayagüez, and Yabucoa). The forecasts are built from Siemens' base commodity prices for natural gas and crude oil prices, which are then adapted to diesel, residual fuel oil, and LPG based on a historical regression analysis of the relationship between these petroleum products and WTI prices. Finally, cost adders are applied to the base commodity prices to derive delivered fuel prices. The adders were derived from current contractual obligations as provided by PREPA's Fuels Office. Delivered coal and LPG fuel prices are also included below.

The EcoEléctrica gas prices assumes that on 2022 the contract is renegotiated and all fixed costs including regasification are blended in a renegotiated fixed payment. The gas prices 2022 onwards reflects the cost of the commodity, liquefaction and transportation only and assume that the long-term contract that EcoEléctrica had for reduced natural gas prices expires.

**Exhibit 7-11. Delivered Aguirre Fuel Price Forecast
(Nominal\$/MMBtu)**

Plant	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre
Year \ Unit	Natural Gas	Gas @ -1SD	Gas @ +1SD	Diesel	Diesel @ -1SD	Diesel @ +2SD	RFO	RFO @ -1SD	RFO @ +2SD
2018	7.70	7.53	7.65	16.44	16.18	16.60	11.48	11.26	11.61
2019	7.48	7.14	7.52	16.18	15.29	16.81	11.26	10.53	11.79
2020	7.56	7.00	7.77	16.62	15.13	18.16	11.64	10.40	12.91
2021	7.99	7.17	8.46	16.98	14.58	19.79	11.94	9.96	14.27
2022	8.11	7.01	8.97	16.79	13.73	21.45	11.79	9.26	15.65
2023	8.37	6.75	9.81	16.88	12.95	24.57	11.87	8.62	18.24
2024	8.67	6.96	10.51	17.16	12.48	29.75	12.11	8.23	22.53
2025	8.93	7.17	10.63	17.72	12.57	31.58	12.57	8.32	24.05
2026	9.14	7.21	11.07	18.35	13.07	32.75	13.11	8.73	25.03
2027	9.23	7.31	11.10	18.84	13.37	32.72	13.52	8.99	25.01
2028	9.34	7.40	11.27	19.43	13.67	34.00	14.01	9.24	26.07
2029	9.40	7.36	11.37	20.33	14.22	35.49	14.76	9.70	27.31
2030	9.59	7.50	11.66	21.21	14.65	37.87	15.50	10.07	29.29
2031	9.65	7.25	11.80	21.76	14.98	38.74	15.96	10.35	30.01
2032	9.90	7.45	12.13	22.17	15.20	40.07	16.31	10.54	31.12
2033	10.07	7.60	12.32	22.59	15.54	40.55	16.66	10.82	31.53
2034	10.31	7.64	12.95	23.02	15.74	42.21	17.02	11.00	32.91
2035	10.55	7.88	13.25	23.45	15.71	42.99	17.39	10.98	33.56
2036	10.73	7.82	13.53	23.89	16.48	43.27	17.76	11.63	33.80
2037	10.96	8.14	13.85	24.35	16.79	44.11	18.15	11.89	34.51
2038	11.06	8.17	13.76	24.83	17.06	45.60	18.55	12.12	35.75
2039	11.15	8.00	13.76	25.31	17.24	46.00	18.96	12.28	36.09
2040	11.30	8.09	13.96	25.80	17.66	47.57	19.37	12.64	37.39



**Exhibit 7-12. Delivered Fuels Price Forecast to San Juan / Palo
Seco / Mayagüez / Yabucoa (Nominal\$/MMBtu)**

Plant	SJ-PS- M-Y	SJ-PS- M-Y	SJ-PS- M-Y	SJ-PS- M-Y	SJ-PS- M-Y	SJ-PS- M-Y	SJ-PS- M-Y	SJ-PS- M-Y	SJ-PS- M-Y
Year \ Unit	Natural Gas	Gas @ -1SD	Gas @ +1SD	Diesel	Diesel @ -1SD	Diesel @ +2SD	RFO	RFO @ -1SD	RFO @ +2SD
2018	7.70	7.53	7.75	16.44	16.18	16.60	11.13	10.91	11.26
2019	7.48	7.14	7.62	16.18	15.29	16.81	10.91	10.17	11.43
2020	7.56	7.00	7.87	16.62	15.13	18.16	11.27	10.04	12.55
2021	7.99	7.17	8.46	16.98	14.58	19.79	11.57	9.59	13.90
2022	8.11	7.01	8.97	16.79	13.73	21.45	11.41	8.88	15.27
2023	8.37	6.75	9.81	16.88	12.95	24.57	11.49	8.23	17.85
2024	8.67	6.96	10.51	17.16	12.48	29.75	11.72	7.84	22.14
2025	8.93	7.17	10.63	17.72	12.57	31.58	12.18	7.92	23.66
2026	9.14	7.21	11.07	18.35	13.07	32.75	12.70	8.33	24.63
2027	9.23	7.31	11.10	18.84	13.37	32.72	13.11	8.58	24.60
2028	9.34	7.40	11.27	19.43	13.67	34.00	13.59	8.82	25.65
2029	9.40	7.36	11.37	20.33	14.22	35.49	14.33	9.28	26.89
2030	9.59	7.50	11.66	21.21	14.65	37.87	15.06	9.63	28.86
2031	9.65	7.25	11.80	21.76	14.98	38.74	15.52	9.91	29.57
2032	9.90	7.45	12.13	22.17	15.20	40.07	15.86	10.09	30.67
2033	10.07	7.60	12.32	22.59	15.54	40.55	16.20	10.37	31.07
2034	10.31	7.64	12.95	23.02	15.74	42.21	16.55	10.53	32.44
2035	10.55	7.88	13.25	23.45	15.71	42.99	16.91	10.50	33.08
2036	10.73	7.82	13.53	23.89	16.48	43.27	17.27	11.14	33.32
2037	10.96	8.14	13.85	24.35	16.79	44.11	17.66	11.39	34.01
2038	11.06	8.17	13.76	24.83	17.06	45.60	18.05	11.62	35.25
2039	11.15	8.00	13.76	25.31	17.24	46.00	18.44	11.76	35.57
2040	11.30	8.09	13.96	25.80	17.66	47.57	18.85	12.11	36.87

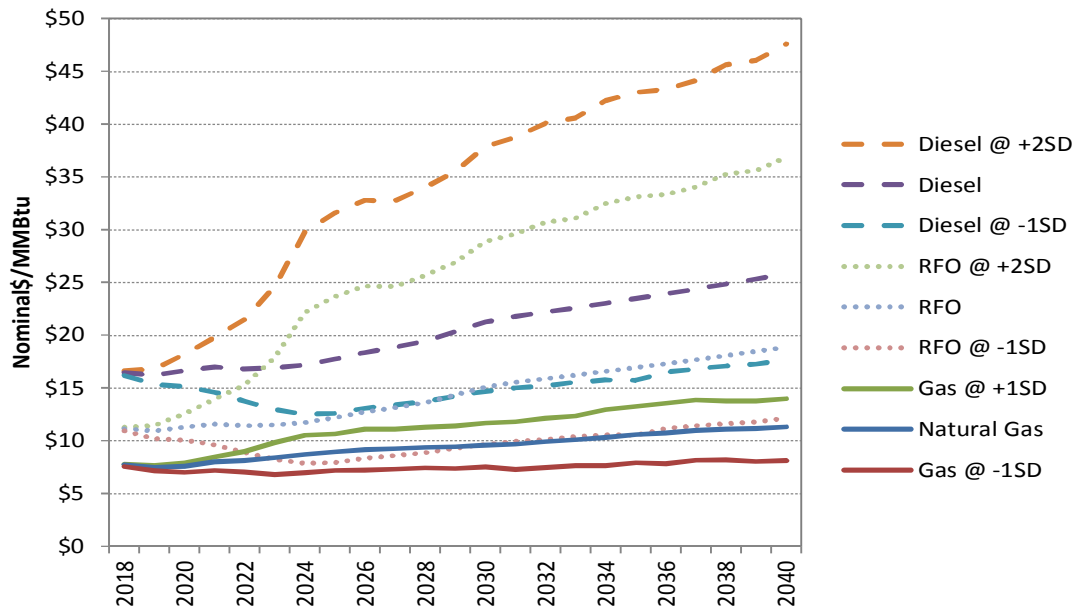
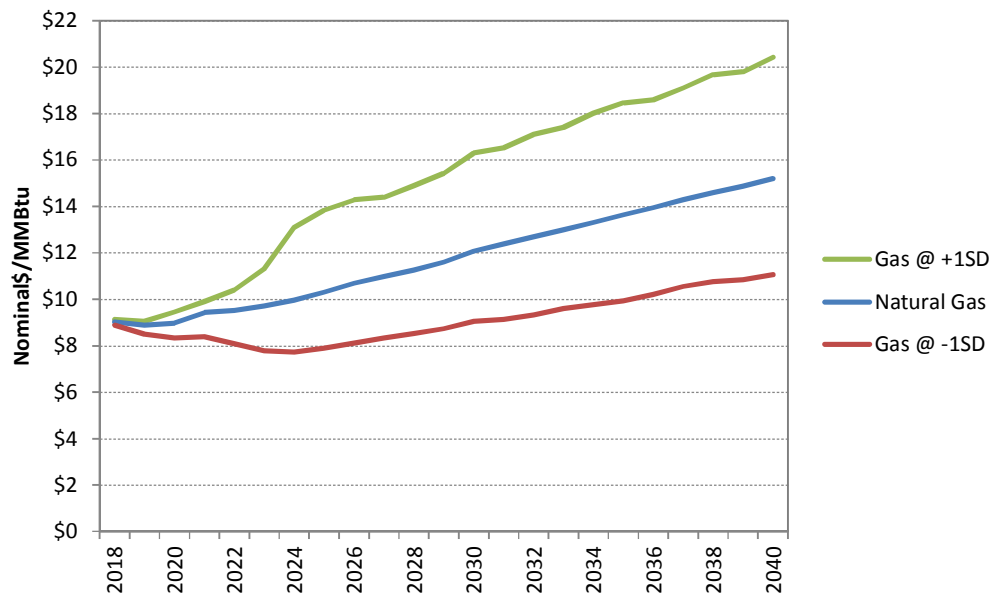


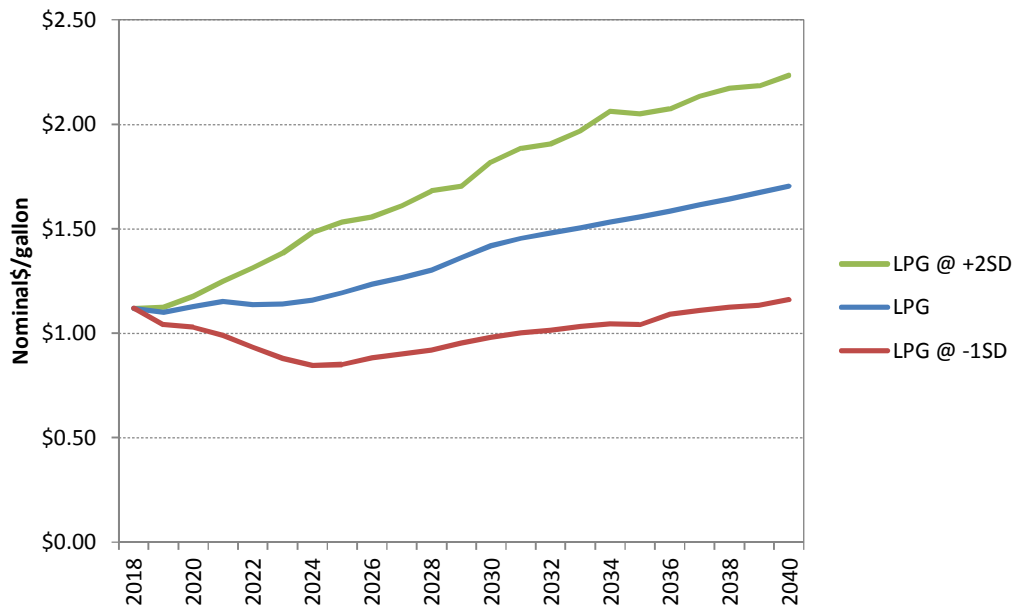
Exhibit 7-13. Delivered Natural Gas to Costa Sur, LPG to Bayamón, and Coal to AES

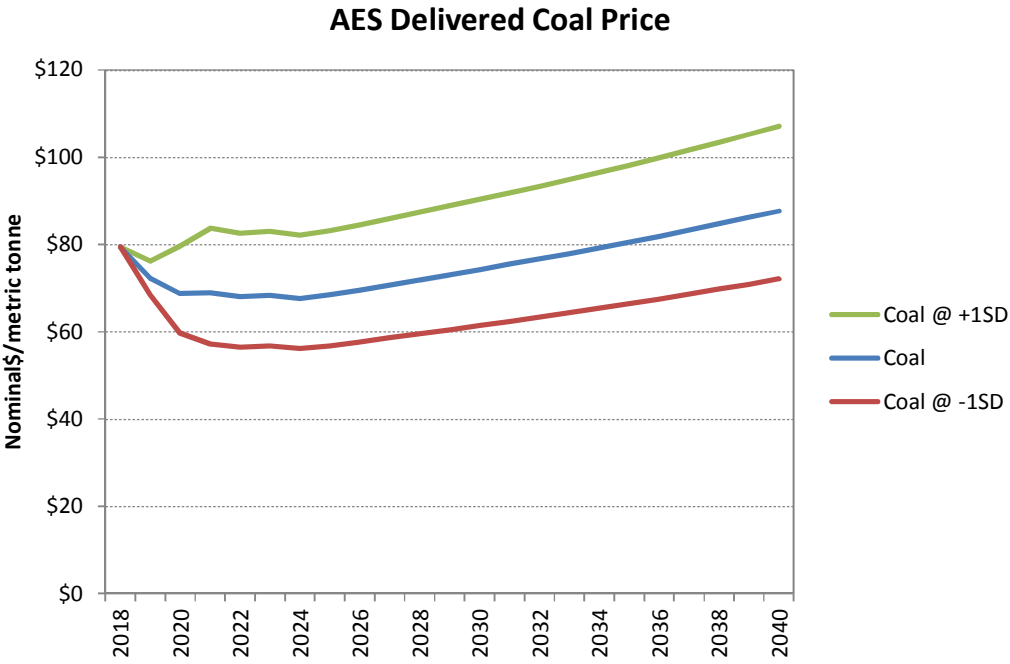
Plant	Costa Sur	Costa Sur	Costa Sur	Bayamón	Bayamón	Bayamón	AES	AES	AES
Fuel	Natural Gas	Gas @ -1SD	Gas @ +1SD	LPG	LPG @ -1SD	LPG @ +2SD	Coal	Coal @ -1SD	Coal @ +1SD
Year \ Unit	Nom\$/MMBtu	Nom\$/MMBtu	Nom\$/MMBtu	nom\$/gallon	nom\$/gallon	nom\$/gallon	nom\$/ton	nom\$/ton	nom\$/ton
2018	9.02	8.88	9.12	1.12	1.12	1.12	79.43	79.43	79.43
2019	8.89	8.51	9.05	1.10	1.04	1.12	72.24	68.55	76.23
2020	8.98	8.32	9.45	1.13	1.03	1.18	68.76	59.63	79.62
2021	9.42	8.39	9.91	1.15	0.99	1.25	69.02	57.21	83.77
2022	9.51	8.08	10.40	1.14	0.93	1.31	68.02	56.42	82.53
2023	9.71	7.79	11.31	1.14	0.88	1.38	68.41	56.73	83.02
2024	9.97	7.73	13.09	1.16	0.85	1.48	67.69	56.15	82.11
2025	10.31	7.89	13.83	1.19	0.85	1.53	68.51	56.81	83.14
2026	10.69	8.10	14.28	1.23	0.88	1.56	69.61	57.69	84.51
2027	10.97	8.34	14.39	1.27	0.90	1.61	70.73	58.59	85.92
2028	11.26	8.53	14.90	1.30	0.92	1.68	71.88	59.51	87.35
2029	11.61	8.74	15.42	1.36	0.95	1.70	73.05	60.44	88.81
2030	12.07	9.05	16.30	1.42	0.98	1.82	74.24	61.39	90.30
2031	12.38	9.12	16.52	1.45	1.00	1.89	75.46	62.37	91.82
2032	12.70	9.32	17.11	1.48	1.01	1.91	76.69	63.35	93.37
2033	12.99	9.59	17.41	1.50	1.03	1.97	77.95	64.36	94.94
2034	13.31	9.78	18.02	1.53	1.04	2.06	79.24	65.39	96.55
2035	13.65	9.92	18.46	1.56	1.04	2.05	80.55	66.44	98.18
2036	13.95	10.21	18.60	1.59	1.09	2.07	81.89	67.51	99.86
2037	14.29	10.55	19.10	1.61	1.11	2.13	83.28	68.63	101.61
2038	14.58	10.75	19.67	1.64	1.12	2.17	84.71	69.77	103.39
2039	14.86	10.85	19.80	1.67	1.13	2.18	86.17	70.94	105.21
2040	15.19	11.06	20.42	1.70	1.16	2.23	87.66	72.12	107.07

Costa Sur Delivered LNG Price



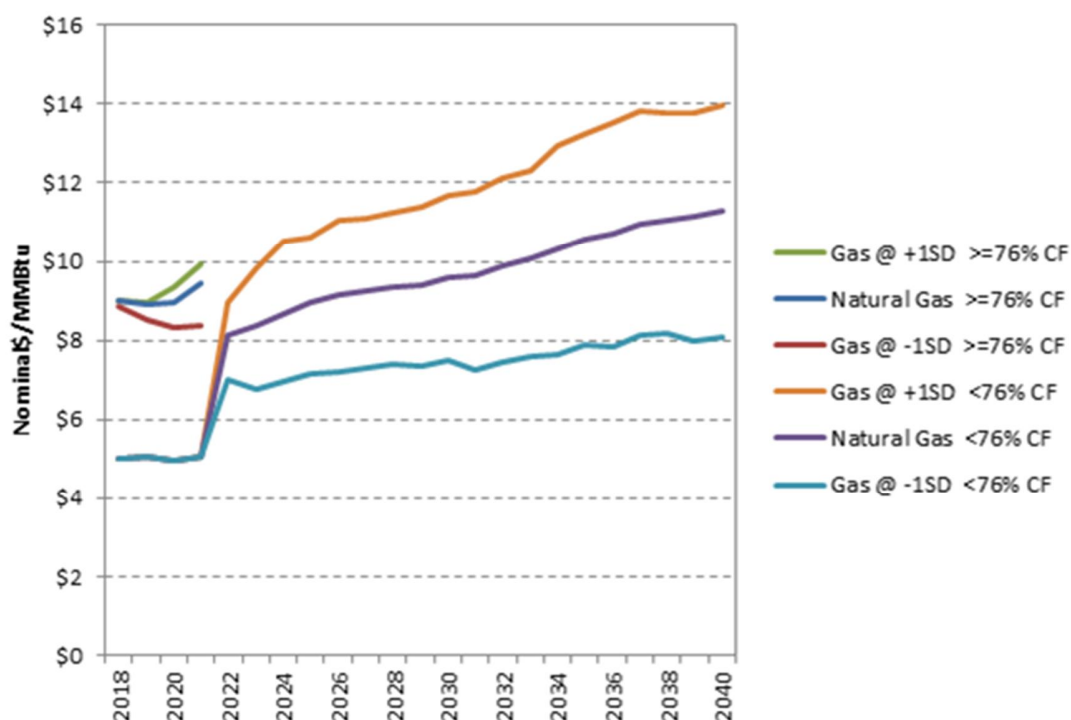
Bayamón Delivered LNG Price





**Exhibit 7-14. Delivered EcoEléctrica Natural Gas Price Forecast
(Nominal\$/MMBtu)**

Plant	EcoEléctrica	EcoEléctrica	EcoEléctrica	EcoEléctrica	EcoEléctrica	EcoEléctrica
Fuel	Natural Gas	Gas @ -1SD	Gas @ +1SD	Natural Gas	Gas @ -1SD	Gas @ +1SD
Capacity Factor	>=76% CF	>=76% CF	>=76% CF	<76% CF	<76% CF	<76% CF
Year / Unit	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu	nom\$/ MMBtu
2018	9.02	8.88	9.02	5.04	5.04	5.04
2019	8.89	8.51	8.95	5.04	5.04	5.04
2020	8.98	8.32	9.36	4.96	4.96	4.96
2021	9.42	8.39	9.91	5.06	5.06	5.06
2022				8.11	7.01	8.97
2023				8.37	6.75	9.81
2024				8.67	6.96	10.51
2025				8.93	7.17	10.63
2026				9.14	7.21	11.07
2027				9.23	7.31	11.10
2028				9.34	7.40	11.27
2029				9.40	7.36	11.37
2030				9.59	7.50	11.66
2031				9.65	7.25	11.80
2032				9.90	7.45	12.13
2033				10.07	7.60	12.32
2034				10.31	7.64	12.95
2035				10.55	7.88	13.25
2036				10.73	7.82	13.53
2037				10.96	8.14	13.85
2038				11.06	8.17	13.76
2039				11.15	8.00	13.76
2040				11.30	8.09	13.96



7.3 Value of Lost Load Estimation

As part of PREPA's Integrated Resource Planning (IRP), Siemens performed a loss of load analysis to assess the likelihood that due to generation and/or transmission outages, the system will be unable to meet load for any period of time. The objective of the analysis is to identify hours in which local or system wide supply may be inadequate to meet demand.

The analysis is performed using a Monte-Carlo simulation to capture loss of load hours (LOLH) and Energy Not Served (ENS) considering the expected performance of the generating fleet and the impact of normal transmission limitations. Additionally, for the impact of weather events two approaches are being considered:

Model a Scenario representative of system condition after a major storm that is expected to occur with relative frequency (e.g. Category 1 Hurricane) and evaluate the LOLH and ENS for a period of 1 month assuming that the system will stay in this condition.

Model a Scenario of the system condition after a major storm that is expected to occur more infrequently (e.g. a Cat 4 Hurricane) in which the system is split into the pre-designed regions (called MiniGrids). Each MiniGrid is assumed to operate in isolation for 1 month. An estimation of load not served during MiniGrid formation can be included.

As part of this IRP, Siemens has estimated the value of lost load (VOLL) based on methodologies applied in other countries or regions. To meet the IRP objectives, Siemens computed a VOLL adjustment for each of the portfolios to evaluate the expected total cost including the cost of maintaining resiliency, which FERC defined as: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability

to anticipate, absorb, adapt to, and/or rapidly recover from such an event.”⁵⁰ The VOLL in turn impacts the selection of the recommended portfolio(s) for PREPA. Specifically, one of the IRP objectives is least cost. Traditional IRPs measure the Net Present Value (NPV) of revenue requirements over the IRP planning horizon. Adding VOLL to the NPV of revenue requirements captures the value of a resilient system in the least cost measure.

VOLL is the standard metric used to estimate the economic impact of disruptions in power service to customers, and thus can provide a measure of the magnitude of benefits associated with decreasing the likelihood of power system interruptions. In principle, VOLL is the value that represents a customer’s willingness to pay for reliable electricity service or to avoid an outage.⁵¹

VOLL is determined by relating the monetary damage arising from a power interruption (due to the loss of economic activities) to the level of the MWh that is not supplied during an interruption. VOLL is generally measured in US\$/MWh. The value of energy not served (ENS) is determined as the VOLL x ENS. VOLL is typically valued separately for different user groups, e.g. residential, commercial and industrial users. The reason for this is that different users are affected differently by the same power interruption.⁵²

7.3.1 Methodological Approaches to Estimating VOLL

There are four key methodologies used for estimating VOLL in the field of economics. Exhibit 7-15 shows a brief explanation of each methodology, followed by its theoretical and practical strengths and weaknesses.

Exhibit 7-15. Key Methodologies Used for Estimating VOLL

Method	Description	Strength	Weakness
Revealed Preference Survey (Market Behavior)	<ul style="list-style-type: none"> Use of surveys to determine expenditures customers incur to ensure reliable generation (i.e., back-up generators and interruptible contracts) to estimate VOLL 	<ul style="list-style-type: none"> Uses actual customer data that is generally reliable. 	<ul style="list-style-type: none"> Only relevant if customers invest in back-up generation Limited consideration of duration and/or timing of outages Difficult for residential customers to quantify expenses
Stated Choice Survey (WTA/WTP)	<ul style="list-style-type: none"> Use of surveys /interviews to infer a customer’s willingness-to-pay (WTP), willingness-to-accept (WTA) and trade-off preferences 	<ul style="list-style-type: none"> More directly incorporates customer preferences Includes some indirect costs and considers duration and/or timing of outages 	<ul style="list-style-type: none"> Time-consuming Need to manage for potential biases Large discrepancy between WTP and WTA Residential customers may give unreliable answers due to lack

⁵⁰ FERC Docket No. AD18-7-000

⁵¹ London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

⁵² Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), (2015, December). Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review. Retrieved from <https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full>.

			of experience
Macroeconomic Analysis	<ul style="list-style-type: none"> Uses macroeconomic data and other observable expenditures to estimate VOLL. This approach estimates VOLL by estimating the value of loss of production for non-residential customers and/or the value loss of leisure time for residential customers. 	<ul style="list-style-type: none"> Few variables Easy to obtain data GNP reasonable proxy for business VOLL 	<ul style="list-style-type: none"> Does not consider linkages between sectors, productive activities Proxies for cost of residential outages may be arbitrary or bias
Case Study Analysis (Blackout Studies)	<ul style="list-style-type: none"> Examines actual outages to determine VOLL. In this approach, the resulting damage costs of a real power interruption are recorded retrospectively. 	<ul style="list-style-type: none"> Uses actual, generally reliable data 	<ul style="list-style-type: none"> Costly to gather data Available case studies may not be representative of other outages/jurisdictions

Note:

WTP: how much they would pay to either avoid a blackout or to be guaranteed a higher level of supply security.

WTA: how much money consumers would have to be offered for them to accept a reduction in supply security or to retain the present level of security instead of being upgraded to a higher level.

Sources:

1. London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf,
2. Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), (2015, December).
3. Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review. Retrieved from <https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full>.

7.3.2 VOLL Trends

VOLL estimates are extremely sensitive to a number of factors, including assumptions used in survey analysis, time and duration of outage, time of advanced notification of outage, customer profile, industry sector and many other factors. Average VOLLs for a developed, industrial economy range from approximately \$9,000/MWh to \$45,000/MWh. Looking on a more disaggregated level, residential customers generally have a lower VOLL (\$0/MWh - \$17,976/MWh) than commercial and industrial (C&I) customers (whose VOLLs range from about \$3,000/MWh to \$53,907/MWh).⁵³ Other trends include:

In general, residential customers are expected to have the lowest VOLLs, while small C/I customers have the highest VOLLs. Small C/I customers are more labor and capital intensive than residential customers and are less likely to prepare for operational risks such as outages by using interruptible contracts and back-up generation as hedges against outages than medium and large C/I customers, leading to generally higher VOLLs.

⁵³ London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

Residential VOLLs in the U.S. are in the \$1,000/MWh – \$4,000/MWh range, while VOLLs in international jurisdictions tend to be much higher. This variation may be due to a variety of factors, including different consumption patterns and costs of electricity in the regions studied, as well as the different methodologies used to estimate VOLL in each study.

Long duration outages lead to higher VOLL as the indirect and induced costs of the outage increase over time (loss of wages, loss of perishable goods, etc.).

Exhibit 7-16 shows the results of recent VOLL studies, broken down according to methodology applied and end-user group. Due to the different degrees of differentiation, the VOLL results of the studies are shown as ranges.⁵⁴

Exhibit 7-16. Results of Recent VOLL Studies

Region/Market	Methodology	System-wide VOLL	Residential	Non-Residential	
				Large C/I	Small C/I
US - Southwest	Analysis of past survey results		\$0	\$8,774	\$35,417
US - MISO	Analysis of past survey results/ Macroeconomic analysis		\$1,735	\$29,299	\$42,256
Austria	Survey		\$1,544		
New Zealand	Survey	\$41,269	\$11,341	\$77,687	\$30,874
Australia - Victoria	Survey	\$44,438	\$4,142	\$28,622	\$10,457
Australia	Analysis of past survey results	\$45,708			
Republic of Ireland (2010)	Macroeconomic analysis	\$9,538	\$17,976	\$10,272	\$3,302
Republic of Ireland (2007)	Macroeconomic analysis	\$16,265			
US - Northeast	Macroeconomic analysis	\$9,283-\$13,925			

Note: All values in 2012 US\$/MWh

Sources: London Economics International LLC. (2013, June). Estimating the Value of Lost Load.

Retrieved from

http://www.ercot.com/content/gridinfo/resource/2015/mktnanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

7.4 First Approach to Calculate Puerto Rico's VOLL

One approach to calculate Puerto Rico's VOLL is to understand which of the nine jurisdictional studies shown in Exhibit 7-16 has the most similarities to Puerto Rico. The applicability of the VOLL estimates from the nine jurisdictional studies to Puerto Rico is determined by considering the similarities between the studied geographic region/market and Puerto Rico. The metrics include: (1) economic and demographic (population and GNP, urban/rural, temperature); (2) electricity consumption patterns; and (3) market design. The mix of customer class also plays a role. In FY2016, residential, small C&I⁵⁵, and medium/large C&I⁵⁶ customers represented approximately 38%, 13% and 50% respectively

⁵⁴ London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktnanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

⁵⁵ Small C&I= customers with an annual consumption under 50,000 kWh

⁵⁶ Medium/Large C&I = customers with an annual consumption over 50,000 kWh

of PREPA's total sales. As shown in Exhibit 7-17, the most applicable study to PREPA is New Zealand, which has a system-wide VOLL of \$41,269/MWh (Residential: \$11,341/MWh, Commercial: \$77,687/MWh, Industrial: \$30,874/MWh) in 2012 dollar.

Exhibit 7-17. Proxy Estimates with Potential Applicability to PREPA

Economic and Demographic Factors	Puerto Rico	New Zealand ⁵	Ireland ⁵	Victoria, Australia ⁵	Australia ⁵
Population Density (people/mile ²) ¹	385	42	168	64	7.3
Average Temperatures (°F) ³	Winter: 64 Summer: 71	Winter: 50-59 Summer: 68-86	Winter: 42 Summer: 58	Winter: 44-59 Summer: 57-79	Winter: 33-91 Summer: 51-97
GNP per Capita (2011 USD\$) ²	35,093	38,563	48,423	59,378	60,979
Rural (%) ³	1% rural	14% rural	38% rural	6.5% rural	11% rural
Electricity Consumption Patterns					
Total Annual Consumption (MWh) ⁴	16,995,838	40,700,000	26,100,000	56,250,000	225,000,000
Peak Demand (MW) ⁴	3,685	6,330	5,090	9,378	13,781
Market Design					
Wholesale Market ⁶	No	Yes	Yes	Yes	Yes
Retail Market ⁶	No	Yes	Yes, but limited	Yes	Yes
Connection with other systems ⁶	No	No	Yes, limited	Yes	No
Overall Applicability⁶		High	High	Moderate	Moderate

Sources:

1. Trading Economics. Retrieved from <https://tradingeconomics.com/puerto-rico/population-density-people-per-sq-km-wb-data.html>
2. World Bank (2015, April). https://data.worldbank.org/indicator/NY.GDP.PCAP.PP.CD?order=wbapi_data_value_2013+wbapi_data_value+wbapi_data_value-last&sort=desc
3. NREL. (2015, March). Energy Transition Initiative. Retrieved from <https://www.nrel.gov/docs/fy15osti/62708.pdf>
4. PREPA (FY2016-2017)
5. London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

Adapting New Zealand's VOLL estimates of each sector and using the expected unserved power (kWh) per sector specific for Puerto Rico (using Puerto Rico's reliability index⁵⁷ and consumer load consumption), Puerto Rico's system wide VOLL results in \$31,897/MWh in 2018 dollar as shown in Exhibit 7-18.

⁵⁷ See Exhibit 7-18 and Exhibit 7-19 for more detail on reliability index.

Exhibit 7-18. 1st Approach VOLL Results Applicable to PREPA

Sector	Number of Customers	Unserved Energy	Cost Per Average MWh	Total Cost
		MWh	2018\$/MWh	2018\$
Residential	1,335,643	10,345	12,269	126,926,034
Small C&I	116,094	3,490	84,045	293,332,602
Medium and Large C&I	11,707	13,650	33,401	455,926,165
Total	1,463,444	27,471	31,895	876,184,801

Sources: Siemens, PREPA

7.5 Second Approach to Calculate Puerto Rico's VOLL

Puerto Rico's power grid is unique as it supports a large commercial and industrial load in a tropical climate and a hurricane zone, with pharmaceuticals, textiles, petrochemicals, and electronics being the major industries.

The Interruption Cost Estimate (ICE) calculator is a publicly available web-based tool developed by Lawrence Berkeley National Laboratory (Berkeley Laboratory) designed to estimate economic costs of power interruptions where you can modify the specific parameters/inputs. It is based on more than 20 years of utility-sponsored surveys on the costs of power interruptions to customers. To ensure its continued effectiveness, the tool continues to be augmented by research on the latest methods for collecting and developing information on the economic consequences of power interruptions on businesses, residences, and society at large.⁵⁸

As the first step, Siemens analyzed the reliability indices including System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) provided by PREPA and shown in Exhibit 7-19. These indices include the effect of all outages including generation transmission and distribution but not the effect of major event days (MED).

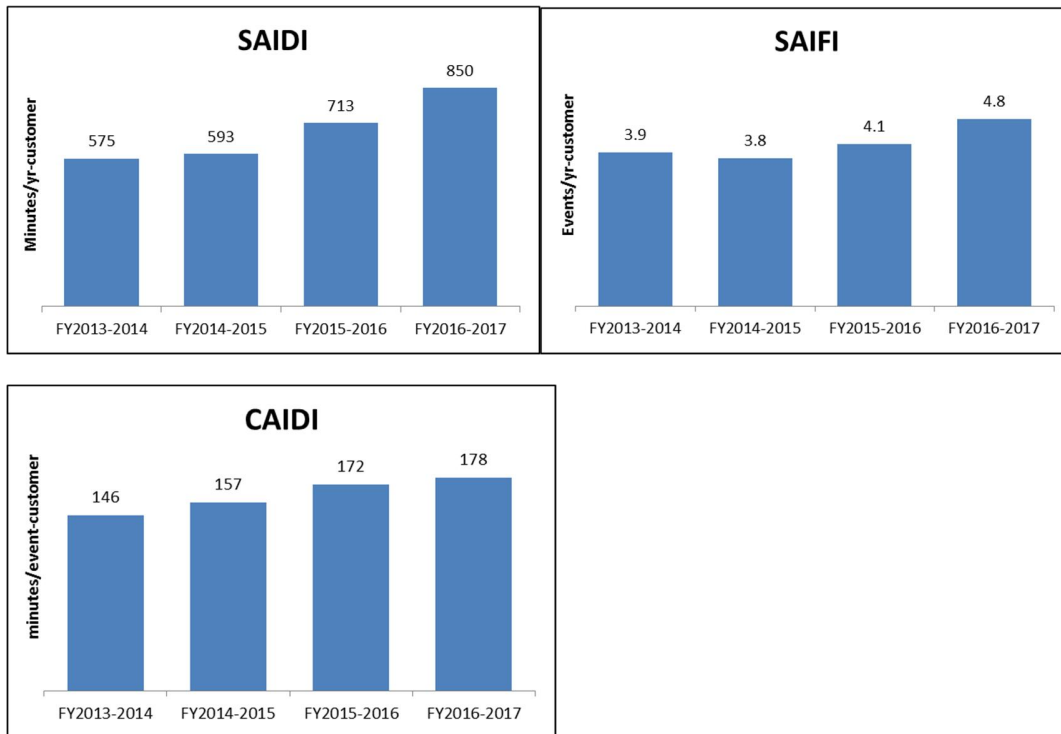
SAIDI index is based on the amount of time the average customers experience a sustained outage in a given year. From FY2013 to FY2016, the average SAIDI for Puerto Rico was about 683 minutes per customer per year.

SAIFI index represents the number of times the average customer experiences a sustained outage in a given year. From FY2013 to FY2016, the average SAIFI for Puerto Rico was about 4.2 events per customer per year.

CAIDI index represents the average restoration time when customers are impacted by a sustained outage. It is determined by dividing SAIDI by SAIFI. From FY2013 to FY2016, the average CAIDI for Puerto Rico was 163 minutes per event per customer.

⁵⁸ Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE) Calculator. Retrieved from <https://icecalculator.com/interruption-cost>

Exhibit 7-19. Puerto Rico's Reliability Indexes (SAIDI, SAIFI, and CAIDI)



Source: PREPA (IEEE Benchmark Report)

As the second step, Siemens introduced other inputs specific for Puerto Rico as presented in Exhibit 7-20.

Exhibit 7-20. PREPA's Parameters to Calculate the Interruption Costs

Parameter	Description	Units	Value
Reliability Index ¹	SAIDI	minute/year-customer	850
	SAIFI	events/year-customer	4.8
	CAIDI	minutes/event-customer	178
Annual Usage per Customer ²	Residential	MWh/customer	5
	Small C&I	MWh/customer	19
	Medium and Large C&I	MWh/customer	721
Number of Customers per Class ²	Residential	Number	1,335,643
	Small C&I	Number	116,094
	Medium and Large C&I	Number	11,707
Industry Composition ³	Construction	%	5%
	Manufacturing	%	9%
	Other Industries	%	86%

Parameter	Description	Units	Value
Household Income ³	Average	USD	27,017
Power Interruption Distribution ⁴	Outages from 5am to 5pm	%	46%
	Outages during Summer (June-Sept)	%	50%
Back-up Generation Percentage per Class ⁴	Small C&I with Back-up or Power Conditioning	%	30%
	Medium/ Large C&I with Back-up or Power Conditioning	%	46%
U.S. State ⁵	U.S. State	U.S. State	Hawaii

Sources:

1. PREPA- IEEE Benchmark Report (FY2016-2017)
2. PREPA (FY2016-2017)
3. U.S. Bureau of Labor Statistics. Retrieved from <https://www.bls.gov/eag/eag.pr.htm>,
4. Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE) Calculator. Retrieved from <https://icecalculator.com/interruption-cost>
5. The ICE Calculator uses a default set of inputs based on the selected state. Puerto Rico is not an option for the ICE Calculator; therefore, Siemens used Hawaii, as it is an island and has a similar GNP as Puerto Rico.

As a result, Siemens estimated Puerto Rico's system-wide VOLL at \$57,940/MWh (Residential: \$4,037/MWh, Small C&I: \$219,237/MWh, Large C&I: \$57,488/MWh) in 2018 dollars. The Berkeley Lab's ICE calculator generated results as shown in Exhibit 7-21.

Exhibit 7-21. Second Approach VOLL Results Applicable to PREPA

Sector	Number of Customers	Unserved Energy	Cost Per Average MWh	Total Cost
		kWh	2018\$	2018\$
Residential	1,335,643	10,345,165	4,037	41,763,433
Small C&I	116,094	3,490,198	219,237	765,180,534
Medium and Large C&I	11,707	13,650,221	57,488	784,723,925
Total	1,463,444	27,471,029	57,940	1,591,667,892

Source: Siemens, Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE) Calculator. Retrieved from <https://icecalculator.com/interruption-cost>

7.5.1 Conclusion

In summary, the two approaches yielded a wide range of estimated VOLL for Puerto Rico. The second approach estimates Puerto Rico's system-wide VOLL at \$57,940 which is \$26,043 higher than the first approach. Exhibit 7-22 summarizes the results for the two approaches. The 2nd approach results in small C&I and Medium/Large C&I VOLL numbers that are out of range compared to the literature VOLL trends discussed above as well as in other documentation reviewed. Additionally, Siemens estimated the VOLL for Puerto Rico using other weakly related markets like the Mid Continent ISO (MISO) in the U.S. and obtained values similar to those of method 1 (27,450 in 2018\$/MWh). Therefore, for the 2018 IRP, Siemens chose to utilize the results from the first approach as proxy to calculate the value of lost load for PREPA customers.

Exhibit 7-22. PREPA VOLL Estimates

Sector	1st Approach (2018\$/MWh)	2nd Approach (2018\$/MWh)
Residential	12,270	4,037
Small C&I	84,051	219,237
Medium and Large C&I	33,403	57,488
System	31,897	57,940

Resource Plan Development

This section presents the Scenarios, Strategies and Sensitivities described in Part 5, the result of the assessment of the resulting generation plans, and metrics and conclusions associated with the plans.

8.1 Overview of Scenario Results

Siemens investigated over 78 LTCE plans as potential resource plans for PREPA. These plans included numerous plausible generation portfolio options including those suggested by stakeholders. These different plans considered points that were critical for the final IRP including, among other issues:

- Uncertainty associated with the future customer demand
- Future prices of generations technologies, e.g., wind, solar, battery storage
- Future prices of fuels, particularly natural gas and the potential availability of infrastructure to deliver additional gas to the island
- Prudent methods to increase resilience and reliability
- Practical limits to PREPA's ability to interconnect new battery energy storage and renewables generation
- Timing of new generation resource additions and the timing of retirements of existing aged fossil fueled resources.

This initial screening of the over 78 LTCE plans resulted in the identification of a final set of 34 LTCE plans⁵⁹ that were assessed to identify the recommended resource plan and the common no regret / minimum regret elements across the plans with perceived merit.

Note that Scenario 2 is not included in the final 34 LTCE considered as it was dropped from further analysis based on the results of the initial screen and in accordance with PREB's Orders.

Exhibit 8-1 below provides the main results of the 34 LTCE plans with their Scenario, Strategy. For the determination of the NPV, we used a discount rate applicable to PREPA as a public utility; for this we selected we 9% (6.86% on a real dollar basis) as this was the same discount rate used in the first IRP and it is based on the assumption that PREPA (or its

⁵⁹ 32 LTCE's plans made it to the final analysis group and to this 2 more plans were added after assessing the results; a plan based on post-processing of S4S2 to reduce the number of peaking generation technologies and a plan for the ESM to reach 50% renewable penetration by 2040.

successors) is able to resolve its current financial issues and can finance its capital expenditures at this rate.

The discount rate used in the NPV calculations above should not be confused with the weighted average cost of capital (WACC) for private parties which is used to determine the fixed costs PREPA would be charged for projects financed by private parties.

Other parameters presented include the average cost of generation (all in) for the period 2019 to 2028 in \$/MWh, the level of RPS compliance achieved by 2038, the present value of the value of the energy that would be lost in case that the system had to revert to MiniGrid isolated operations for 1 month every 5 years (see further details in this section), the lowest reserve margin observed, a ratio of photovoltaic generation added to the system to the peak load as an indication of technology risk (i.e. potential challenges to manage generation whose output can be much higher than the peak load), reduction in emissions and capital costs.

To help visualize the results in Exhibit 8-1 we provide below a color scorecard for the different plans /scenarios under similar external conditions (load growth and cost of renewable) and we compare graphically the NPV.

Exhibit 8-1: Summary of Plans Results

Count	Case ID	Scenario	Strategy	Sensitivity	Load	NPV @ 9% 2019 2038 \$000	Average 2019-2028 2018\$/MWh	RPS 2038	NPV Deemed Energy Not Served MiniGrid Ops \$000 (1)	Lowest Reserve Margin	PV / Max Demand	Emissions Reductions	Capital Investment Costs (\$ Millions)
1	S1S2B	1	2		Base	16,216,702	101.1	81%	235,982	44% (2025)	175%	86%	6,579
2	S1S2H	1	2		High	17,903,791	101.7	89%	199,201	49% (2028)	178%	81%	7,694
3	S1S2L	1	2		Low	14,748,153	99.7	71%	185,656	49%(2025)	170%	87%	5,790
4	S1S3B	1	3		Base	16,076,200	100.4	76%	250,482	41%(2024)	175%	84%	6,645
5	S1S3H	1	3		High	17,835,218	101.3	93%	410,097	30% (2032)	175%	83%	7,287
6	S1S3L	1	3		Low	14,680,008	99.1	71%	265,850	39% (2028)	167%	87%	5,668
7	S1S2S1B	1	2	1	Base	15,434,453	97.1	84%	273,910	41%(2025)	180%	87%	6,718
8	S1S2S2B	1	2	2	Base	17,315,412	100.1	84%	338,854	51%(2033)	189%	81%	7,115
9	S1S2S3B	1	2	3	Base	15,858,601	100.3	59%	126,327	45%(2028)	124%	91%	5,275
10	S1S1B	1	1		Base	15,395,763	100.5	81%	594,235	50%(2025)	175%	86%	6,308
11	S3S2B	3	2		Base	14,714,793	93	87%	80,098	41% (2024)	189%	53%	7,247
12	S3S2H	3	2		High	16,141,041	94	99%	95,517	29%(2028)	188%	84%	7,931
13	S3S2L	3	2		Low	13,596,756	92.8	76%	54,035	32%(2025)	180%	88%	6,281
14	S3S3B	3	3		Base	14,749,058	93.3	87%	164,509	32%(2024)	186%	87%	7,059
15	S3S3H	3	3		High	16,181,429	93.9	96%	136,258	33%(2025)	188%	84%	8,065
16	S3S3L	3	3		Low	13,566,244	91.8	96%	173,547	33% (2025)	177%	88%	6,137
17	S4S2B	4	2		Base	15,195,166	96.3	49%	228,285	42% (2028)	104%	76%	6,131
18	S4S2B-M	4	2		Base	15,143,289	96.0	49%	226,360	42% (2028)	104%	76%	6,132
19	S4S2H	4	2		High	17,046,702	99.0	57%	169,249	38% (2034)	106%	72%	7,536
20	S4S2L	4	2		Low	14,094,994	96.6	48%	247,228	44% (2030)	108%	80%	5,468
21	S4S3B	4	3		Base	15,290,245	96.4	54%	343,059	30% (2030)	110%	77%	6,610
22	S4S3H	4	3		High	16,646,410	96.7	59%	452,412	32% (2028)	106%	72%	7,454
23	S4S3L	4	3		Low	14,013,227	95.8	45%	332,614	42% (2029)	99%	78%	5,656
24	S4S2S3B	4	2	3	Base	14,919,759	95.1	47%	262,528	37% (2026)	101%	54%	5,523
25	S4S2S4B	4	2	4	Base	15,288,253	96.4	53%	482,855	35% (2037)	110%	77%	6,509
26	S4S2S5B	4	2	5	Base	16,266,967	101.8	52%	195,783	47% (2037)	110%	75%	6,264
27	S4S2S6B	4	2	6	Base	16,203,306	101.7	22%	166,167	42% (2028)	37%	72%	5,821
28	S4S1B	4	1		Base	15,352,066	97.3	51%	476,701	29% (2034)	110%	74%	6,717
29	S5S1B	5	1		Base	14,769,222	92.7	49%	1,142,452	30% (2026)	101%	77%	5,468
30	S5S1S5B	5	1	5	Base	15,417,661	95.7	54%	1,027,570	32% (2030)	110%	76%	5,987
31	ESM Plan	4	2		Base	15,186,419	95.4	24%	319,291	45% (2028)	42%	66%	4,098
32	ESM high	4	2		High	16,589,582	95.8	40%	484,235	40% (2034)	69%	69%	4,954
33	ESM low	4	2		Low	14,111,364	95.7	20%	330,499	49% (2029)	37%	71%	3,355
34	ESM 50% RPS	4	2		Low	15,216,945	95.7	44%	306,724	47% (2028)	102%	75%	5,131

As can be observed in the exhibit below where the key metrics were normalized so that green is the best outcome and red is the worse; Scenario 1 (no new gas) has the worst performance in terms of costs and technology risk, but is the best on environmental and RPS. Scenario 4 and 5 with Strategy 1 and 3 have good to acceptable performance across most variables, but as expected Strategy 1 underperform with respect of the deemed cost of energy not served and S4S3 is acceptable (yellow) across all variables except in capital that underperforms. This analysis brings us to Scenario 4 Strategy 2 (Modified as described later in this report S4S2-M) and the ESM Base and ESM with the option to extend to 50% RPS. As can be observed, the ESM with 50% RPS has them best outcomes followed by S4S2B and the base ESM.

Exhibit 8-2: Scorecard for Scenario 1, ESM, Scenario 4 and Scenario 5 for the Reference Scenario (Base Load Growth, Renewable prices and fuel)

	S1S2B	S1S3B	S1S1B	ESM Plan	ESM 50% RPS	S4S2B-M	S4S1B	S4S3B	S5S1B
NPV @ 9% 2019-2038 \$000	Red	Red	Yellow	Green	Green	Green	Yellow	Yellow	Green
Average 2019-2028 2018\$/MWh	Red	Red	Red	Green	Green	Green	Yellow	Yellow	Green
Capital Investment Costs (\$ Millions)	Orange	Orange	Yellow	Green	Green	Yellow	Red	Orange	Green
NPV Deemed Energy Not Served	Green	Green	Orange	Yellow	Green	Green	Orange	Yellow	Orange
RPS 2038	Green	Green	Green	Orange	Yellow	Yellow	Yellow	Yellow	Yellow
Emissions Reductions	Green	Green	Green	Orange	Green	Yellow	Yellow	Yellow	Yellow
Technology risk (PV / Max Demand)	Red	Red	Red	Green	Yellow	Yellow	Yellow	Yellow	Yellow

For the case of high load growth, we observe below that Scenario 4 Strategy 3 has the best outcomes followed by the ESM and Scenario 2 Strategy 2. This results indicates that it is a good hedge to maintain the option of the CCGT at Mayagüez that this LTCE proposes in addition to the CCGTs in Palo Seco and Yabucoa.

Exhibit 8-3: Scorecard for Scenario 1, ESM, and Scenario 4 and Scenario 5 for the High Load Growth Case.

	S1S2H	S1S3H	S4S2H	ESM high	S4S3H
NPV @ 9% 2019-2038 \$000	Red	Red	Green	Light Green	Green
Average 2019-2028 2018\$/MWh	Red	Red	Green	Light Green	Green
Capital Investment Costs (\$ Millions)	Red	Yellow	Green	Orange	Green
NPV Deemed Energy Not Served	Green	Yellow	Yellow	Green	Green
RPS 2038	Green	Green	Orange	Yellow	Yellow
Emissions Reductions	Green	Green	Yellow	Yellow	Green
Technology risk (PV / Max Demand) ⁴	Red	Red	Green	Yellow	Yellow

For low load both the ESM and S4S3 have the best results with the exception of the RPS in the ESM, but as indicated earlier, the renewable additions for the ESM case can be easily modified.

Exhibit 8-4: Scorecard for Scenario 1, ESM, and Scenario 4 and Scenario 5 for the Low Load Growth Case.

	S1S2L	S1S3L	ESM low	S4S2L	S4S3L
NPV @ 9% 2019-2038 \$000	Red	Red	Green	Green	Green
Average 2019-2028 2018\$/MWh	Red	Red	Green	Yellow	Green
Capital Investment Costs (\$ Millions)	Red	Orange	Green	Yellow	Green
NPV Deemed Energy Not Served	Green	Yellow	Yellow	Light Green	Green
RPS 2038	Green	Green	Orange	Yellow	Yellow
Emissions Reductions	Green	Green	Yellow	Yellow	Green
Technology risk (PV / Max Demand) ⁴	Red	Red	Green	Yellow	Yellow

Scenario 3 is not compared in this way as it has lower cost of renewable and would render the comparison invalid, however we address Scenario 3 in the next comparison.

Finally, Exhibit 8-5 below provides a summary of the NPV results of the ten primary Scenario and strategy combinations for the Base, High and Low load forecasts.

Exhibit 8-5: Summary Scenarios



As can be seen in prior table and chart, Scenario 3 Strategy 2 (S3S2) and Scenario 3 Strategy 3 (S3S3) provide the lowest (\$14.71B) and second lowest (\$14.75B) NPV for the base load forecasts. These two plans assume a deeper reduction in the cost of renewable and storage (using the NREL Low for PV). However, these plans may have practical implementation issues given that the amounts of PV output over the long term is almost double the forecasted peak load. During periods of light load the PV output would be an even higher multiple of forecasted peak load. This large renewable capacity would strain the remaining resources on the system including the storage and could lead to unexpected curtailment. For this reason, we see this case as a guide to potential enhancements that can be considered if both the cost of PV declines faster than the base case and greater amounts of renewable can be safely operated. However, Scenario 3 is not considered the preferred portfolio due to its assumed deep reduction in renewable prices.

Scenario 5 Strategy 1 (S5S1) provides the second lowest NPV results (\$14.77B) for the base load forecast. This LTCE plan is based on a centralized strategy and was determined not to be the preferred resource plan, due to the high levels of load shedding that would be required during a major storm that segments the island in the MiniGrids proposed, as was also shown before

The fourth and fifth lowest NPV were for the ESM plan (\$15.19B) and Scenario 4 Strategy 2 (S4S2) (\$15.20B). These plans were determined to be practical and low cost plans that contain the recommended path forward. In fact, these plans also contain a common set of no regret / minimum regret elements in the near term plan that were shared by some of the other LTCE plans with favorable results depending on the future conditions.

The remainder of the LTCE plan (i.e., S1S1, S1S2, S1S3, S4S1, S4S3) had higher NPV costs for the Base load forecast and no other differentiators that would have positioned them as more desirable than ESM and S4S2.

We discuss each of the Scenarios below.

8.2 Scenario 4 Results

The generation portfolio identified as Scenario 4 Strategy 2 (S4S2) result in a plan that meets the criteria of least cost, resilience and viability in terms of installation of solar and battery storage, as well as added resilience and flexibility provided by local thermal generation within the MiniGrids. The Strategy 2 used for the formulation of the portfolio focused on distributed resources, which translate into a requirement that at least 80% of the peak demand needs to be supplied locally. This strategy provides a distributed system of flexible generation and MiniGrids that is more resilient and locates supply resources closer to the customer. The portfolio generation mix was also confirmed to be able to supply the forecasted levels of critical load.

The Scenario 4 considers the option of development of LNG terminals at Yabucoa (east coast) and Mayagüez (west coast) through ship-based LNG. The Scenario also includes gas in the north delivered through land-based LNG at San Juan. The Scenario uses the solar and storage costs and availability based on reference case assumptions.

The following additional assumptions were also included in the simulation of this Scenario:

- Load forecast is assessed at Base, High and Low cases
- The AES PPOA is assumed to expire in 2027 and EcoEléctrica is assumed to renew in 2022 with a 55% reduction of the fixed payments (new 2022 payment \$108 million down from 240 million the prior year) and the increased ability to cycle as required to support the integration of renewables.
- San Juan Units 5 & 6 are converted to gas in June 2019. The cost of the conversion is assumed to be structured as a capacity payment of \$5 million on an annual basis per unit ending on 06/30/2024.
- San Juan units are subjected to fuel constraints of delivery to San Juan (ship-based fuel constraints for July 2019-June 2025, and land-based LNG constraints from July 2024 through the end of the forecast period.
- Energy Efficiency programs are assumed to meet the requirement of Regulation No. 9021, i.e., 2% per year of incremental savings attributable to new energy efficiency programs for 10 years.
- The Scenario assumes solar and storage costs and availability based on reference case assumptions. New PV installations are limited to 300 MW annually in 2020 and 2021 and 600 MW annually thereafter. Storage installations are limited to 180 MW annually in 2019, 300 MW annually in 2020 and 2021, and 600 MW annually thereafter.
- Minimum RPS targets; 12% by 2022, 15% by 2027 and 20% by 2035. The plan achieved much higher levels.

As indicated in Part 5, the Scenario 4 was evaluated considering three load growth levels (low, base and high) and two strategies (2 and 3). Strategy 1 with the base load growth was

also considered as well as two sensitivities; no land based LNG terminal in San Juan (sensitivity 4) and high cost of gas (sensitivity 5). Exhibit 8-6 has a summary of the generation expansion under all cases considered for Scenario 4 that will be discussed in further detail in the next sections. As can be observed there is significant agreement on results, which can be used to identify the preferred robust decisions; i.e. those that would minimize the regret should future conditions be different than those anticipated in the assumptions (e.g. higher prices than expected, lower load, etc.).

Exhibit 8-6. Scenario 4 Summary of results

Case ID	Large & Medium CCGTs and peakers								Renewable and storage					
	F - Class Palo Seco 2025	F - Class Costa Sur 2025	F-Class Mayaguez 2025	F-Class Yabucoa 2025	Small CCGT (LPG/NG) North	F - Class San Juan 2029	Medium CCGT Yabucoa 2024	Peakers (small CC) 2019-2029	New Solar 2019 - 2022	BESS 2019 - 2022	New Solar 2023 - 2028	BESS 2023 - 2028	New Solar Total	BESS Total
S4S2B	✓	✓	✓	X	X	X	X	372	1200	900	1020	40	2220	1080
S4S2B-M	✓	✓	✓	X	X	X	X	387	1200	900	1020	40	2220	1080
S4S2H	✓	✓	✓	X	X	✓	✓	479	1200	800	1380	0	2580	960
S4S2L	✓	✓	X	X	X	X	X	280	1200	1100	900	60	2100	1160
S4S3B	✓	✓	✓	X	X	X	X	388	1200	900	1140	160	2340	1540
S4S3H	✓	✓	✓	✓	X	X	X	440	1200	1000	1380	0	2580	1420
S4S3L	✓	✓	X	✓ (2028)	X	X	X	280	1200	1080	720	0	1920	1080
S4S2S3B	✓	✓	X	X	X	X	X	303	1200	920	960	20	2160	1020
S4S2S4B	✓	✓ 2027	X	✓	X	X	X	327	1200	1160	1140	0	2340	1220
S4S2S5B	✓	✓	X	X	X	X	✓	591	1200	580	1140	80	2340	960
S4S2S6B	✓	✓	✓ (2025)	X	X	✓ (2028)	✓	204	720	620	0	0	780	620
S4S1B	✓	✓	✓	X	X	X	X	324	1200	900	1140	0	2340	1460

Strong no regret with no variation among cases that support decision being made
Decision common to multiple cases / little variation between scenarios that allow the decision to be taken
Decision common to few scenarios that allow the decision to be taken
Decision common to one scenario, PV / BESS: outlier or close follow up required.

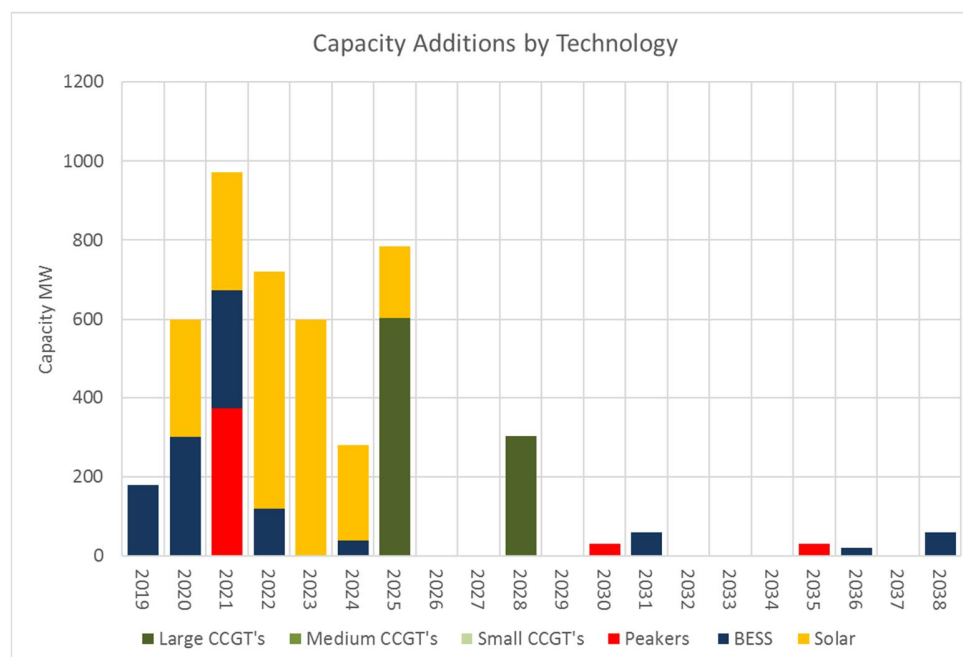
8.2.1 Capacity Additions and Retirements

The economic simulation of Scenario 4 under strategy 2 results in 2,220 MW of utility scale PV additions over the study period with the first 300 MW added in 2020. A total of 1,200 MW is added in the first four years of the plan, by 2022, which is consistent across the high and low load cases and it is also seen across the sensitivities that drive higher levels of renewable; high gas prices or lower costs of renewables (see Exhibit 8-6). Furthermore, even in Sensitivity 6 with high capital costs for renewables, the amount of solar built is consistent with 300 MW per year in 2020 and 2021.

The analysis of S4S2 and its sensitivities indicates that the recommendation to build at least 1,200 MW of solar in the short to medium-term in Puerto Rico, is robust (minimum regret) provided that the capital cost for solar photovoltaic are as projected (see Part 6 of this report) and that PREPA is able to contract for and interconnect this aggressive level of new PV additions. If the capital costs of solar photovoltaic projects result to be higher than forecasted, then smaller amounts of photovoltaic may be advisable (780 MW by 2022, as shown in Exhibit 8-6 S4S2S6B – Sensitivity 6).

In Scenario 4, 1,080 MW of battery energy storage is built over the study period, primarily in 2019-2022, when 900 MW is built. In the high and low load cases, 800 to 1,100 MW of storage is built, respectively, in the same period (see Exhibit 8-6). A robust decision is to build a minimum of 800 MW of storage by 2022, with the expected storage capital prices. However, since the benefits of the battery energy storage are largely drawn from its support of renewables, should installations of renewables be less than expected, it may be desirable to slow the addition of the energy storage so that it better aligns with the rate of renewable additions. With high storage prices, the recommended storage addition is reduced to 620 MW by 2022.

Exhibit 8-7:S2S2 Portfolio Base Load Forecast Capacity Additions



Technology / MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Large CCGT's	0	0	0	0	0	0	604	0	0	302
Medium CCGT's	0	0	0	0	0	0	0	0	0	0
Small CCGT's	0	0	0	0	0	0	0	0	0	0
Peaking Units	0	0	372	0	0	0	0	0	0	0
BESS	180	300	300	120	0	40	0	0	0	0
Total Distachable Additions	180	300	672	120	0	40	604	0	0	302
Solar	0	300	300	600	600	240	180	0	0	0
Total Additions	180	600	972	720	600	280	784	0	0	302

Three large F-Class CCGTs are installed (302 MW each for a total of 906 MW) in Scenario 4 under the base load forecast, one in Palo Seco (Bayamon) in 2025, one in Costa Sur (Ponce West) in 2025, and one is installed in 2028 in Mayagüez, after AES retirement. In the high load case, the same units are added, in addition to a fourth F-Class CCGT at San Juan in 2029 and a medium CCGT in Caguas (Yabucoa). With respect to this last high load case, and as will be shown below using Strategy 3, a plan was identified where a F-Class CCGT is installed at Caguas (Yabucoa) instead of the medium CCGT and the F-Class CCGT at San Juan. This option results in lower costs and may indicate a preferred strategy if this high load were to happen.

In the low load case, the F-Class at Palo Seco and Costa Sur are added but not the F-Class in Mayagüez in 2028 (see Exhibit 8-6).

The F-Class CCGT at Palo Seco was also called for under all Scenarios that considered that a land-based LNG terminal could be developed at San Juan with a pipeline connecting to the Palo Seco plant; that is Scenario 3 and Scenario 5. The F-Class in Palo Seco was also called for in Scenario 2 that was dropped from further analysis after the initial runs. Moreover, in most Scenarios this development should be carried out as soon as possible (assumed to be 2025 at the earliest) and only under Scenario 3, that assumes a deeper reduction in the cost of renewable, would the F-Class unit at Palo Seco be delayed to 2027 installation as

shown in Exhibit 8-6. Thus, Siemens considers that adding a F-Class CCGT at Palo Seco is a no regret decision.

Similarly, all Scenarios have a new F-Class CCGT needed at Costa Sur by 2025 with EcoEléctrica supply agreement allowed to expire. The decision to build an F-Class in Costa Sur is least cost, with the only caveat that should the renegotiation of the EcoEléctrica supply agreement yield a new agreement with lower fix payments and higher dispatch flexibility, it could be possible to avoid the need for the F-Class CCGT at Costa Sur and maintain EcoEléctrica instead. Thus, a minimum regret decision is to advance both processes in parallel; the CCGT at Costa Sur and the negotiation with EcoEléctrica.

As will be presented below (Section 8.2.10), the base case for Strategy 3 has the same decisions for the combined cycle generation and very similar decision for the renewables for (see Exhibit 8-6). Under the high load forecast Strategy 3 calls for an F-Class CCGT at Caguas (Yabucoa) and this results in lower cost than the corresponding case under Strategy 2 (2% lower). For the low load, Strategy 3 also calls for the F-Class CCGT at Yabucoa but by 2028 (rather than 2025 for Strategy 2) and reduces the amount of PV and storage as compared with Strategy 2 (costs are about 1% lower).

Based on the results described above, the decision to build a large combined cycle at Mayagüez and/or Yabucoa should be part of the least cost path and hence it is recommended to start the preliminary engineering and environmental assessment for both generating units and gas terminals.

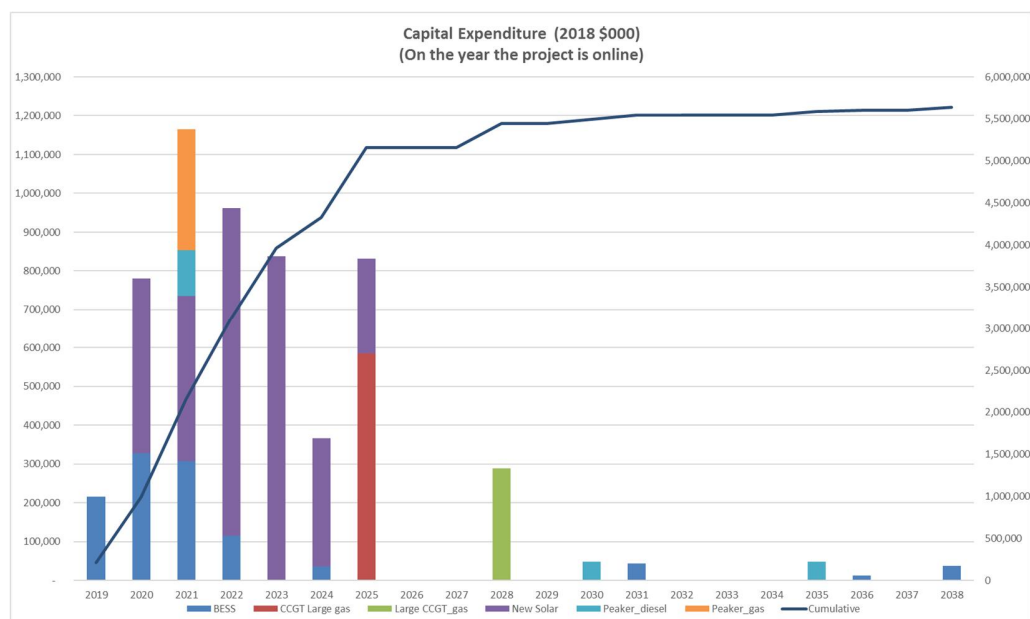
In addition, Scenario 4 calls for 436 MW of peaking generation is added (133 MW diesel and 303 MW gas fuel based - containerized) by 2038. Most of this generation is required to cover critical load and provide MiniGrid resiliency (Carolina, Caguas, Ponce East (Jobos), Cayey and Mayagüez North).

As discussed previously, San Juan 5 & 6 converted to gas in 2019. San Juan 6 is then retired by 2035 due to economics.

8.2.2 Capital Expenditures

While expressed as capital expenditures, we assumed that all new generation would be acquired through an RFP process for PPOAs and hence the capital investments will be made by developers and covered in a fixed charge calculated using the WACC and the economic life. The figure below shows the levels of capital expenditures required for the S4S2 Portfolio under the Base Load forecast. These capital costs are all in and include interest during construction but are expressed as a single capital expenditure in the year the plants come online (also known as overnight capital costs). We observe that the largest investment is required for the generation assets expected to be in service in 2021 (\$1.16 billion), for new solar, peaking generation and storage. Total capital investments reach \$ 5.6 billion (US\$ 2018) by 2038.

**Exhibit 8-8: S4S2 Portfolio Base Load Forecast
Capital Expenditure**



CapEx \$000 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
BESS	216,103	328,152	307,746	115,022	-	35,519	-	-	-	-
CCGT Large gas	-	-	-	-	-	-	585,827	-	-	-
Large CCGT_gas	-	-	-	-	-	-	-	-	-	288,353
New Solar	-	451,884	428,490	847,619	837,798	331,542	245,788	-	-	-
Peaker_diesel	-	-	116,769	-	-	-	-	-	-	-
Peaker_gas	-	-	312,088	(0)	0	-	(0)	0	-	(0)
Grand Total	216,103	780,036	1,165,094	962,641	837,798	367,061	831,614	0	0	288,353

8.2.3 Capacity Retirements

The installation of the PV and Storage in 2020, together with the long-term reduction in demand allows for the economic retirement of Aguirre ST 1 and 2 (end of 2019), Palo Seco ST 3 (end of 2023) and San Juan Steam units 7 & 8 (end of 2023 & 2021, respectively). Palo Seco ST 4 is retired by the end of 2024 due to the entry in 2025 of the new combined cycle at Palo Seco.

Even under high load conditions, the Aguirre units are retired by the end of 2019 (start on 2020), but the Palo Seco 3&4 and San Juan 7&8 units stay online until the end 2024, when they are retired by the entry of the large combined cycle at Palo Seco. Under low load conditions, the retirement plan stays mostly the same as under base case load.

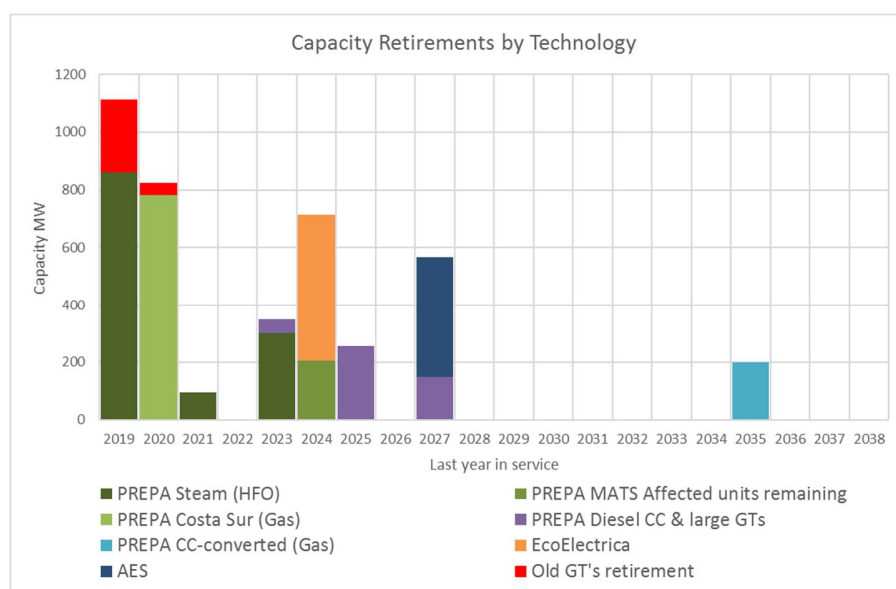
EcoEléctrica is economically retired by the end of 2024, in spite of the reduction the fixed payments, and assuming the unit has more flexibility by allowing it to cycle on a weekly basis. This retirement is triggered by the entry of a new CCGT at Costa Sur (F-Class) and happens irrespective of the load forecast.

Costa Sur 5 & 6 last year in service is 2020 as it could not compete with EcoEléctrica, under the base load and low load forecast. Under the high load case, one of the units stays online longer until the end of 2021.

The Aguirre CC 1 is retired in 2025, but the other is maintained online for reserves. Cambalache units 2 & 3 retire in 2031 and 2023 respectively. The Aero Mayagüez peakers are all retired by the end of 2027 triggered by the entry of the new combined cycle in 2028 under this Portfolio and base load forecast and high load forecast. On the low load forecast the Aero Mayagüez is required (at least 100 MW), for local reserves to the end of the forecast.

AES is retired by 2028, not economically but by model input.

Exhibit 8-9: Scenario 4 Capacity Retirements (last year in service)



Technology / MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PREPA Steam (HFO)	862	0	95	0	300	0	0	0	0	0
PREPA MATS Affected units remaining						206	0	0	0	0
PREPA Costa Sur (Gas)	0	782	0	0	0	0	0	0	0	0
PREPA Diesel CC & large GTs	0	0	0	0	50	0	257	0	150	0
PREPA CC-converted (Gas)	0	0	0	0	0	0	0	0	0	0
EcoElectrica	0	0	0	0	0	507	0	0	0	0
AES									416	0

Finally, the natural gas converted San Juan 6 is retired by 2035. San Juan 5 remains online under the base load forecast. Under a high load Scenario, both units are retired earlier (in 2030 and 2032). In contrast, under a low load, both are maintained for the duration of the planning period. Based on the above, it can be concluded that these units are expected to remain online once converted, at least through the end of the decade.

Overall, the steam units running on fuel oil have costs above those of the combination of PV + Storage and their inflexibly would create renewable curtailment, hence all the steam units are retired.

8.2.4 Future Generation Mix and Reserves

As shown in the exhibit below, the system transitions from one based on coal and oil to a system dominated by natural gas, renewables and energy storage. By 2038, 68% of the installed capacity in the system consists of renewable generation or facilities in place for its integration (battery storage), including solar and CHP distributed generation. Total renewable generation accounts for 47% of the total by 2038 with gas generation accounting for 48% of the total (Exhibit 8-11). Most of the gas generation comes from the three new large CCGTs and San Juan conversions. As such, the development of the LNG terminals is critical to reach the full potential of the new gas units.

As PREPA's units and the thermal PPOA's are phased out, the operating reserves decline from 79% in 2019 to a low of 44% by 2028 with the retirement of AES and three GTs at Mayagüez, despite the addition of the new CCGT in Mayagüez. Operating reserves rise afterwards driven by the decline in load and the addition of 200 MW in peakers and storage in the last ten years. The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this Scenario with the reserve margin of at minimum 37% through the forecast.

Exhibit 8-10: Scenario 4 Installed Capacity Mix

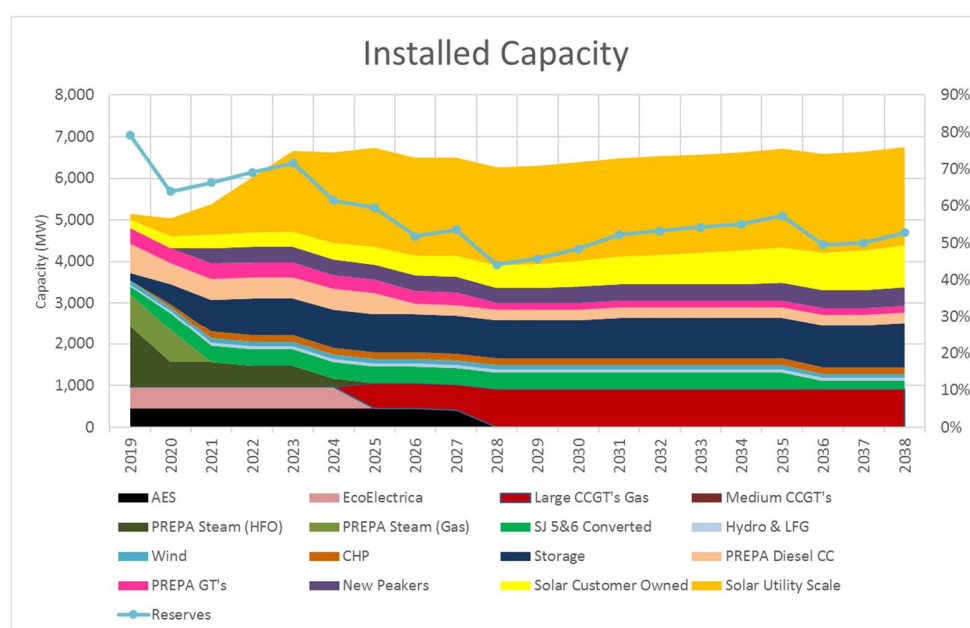
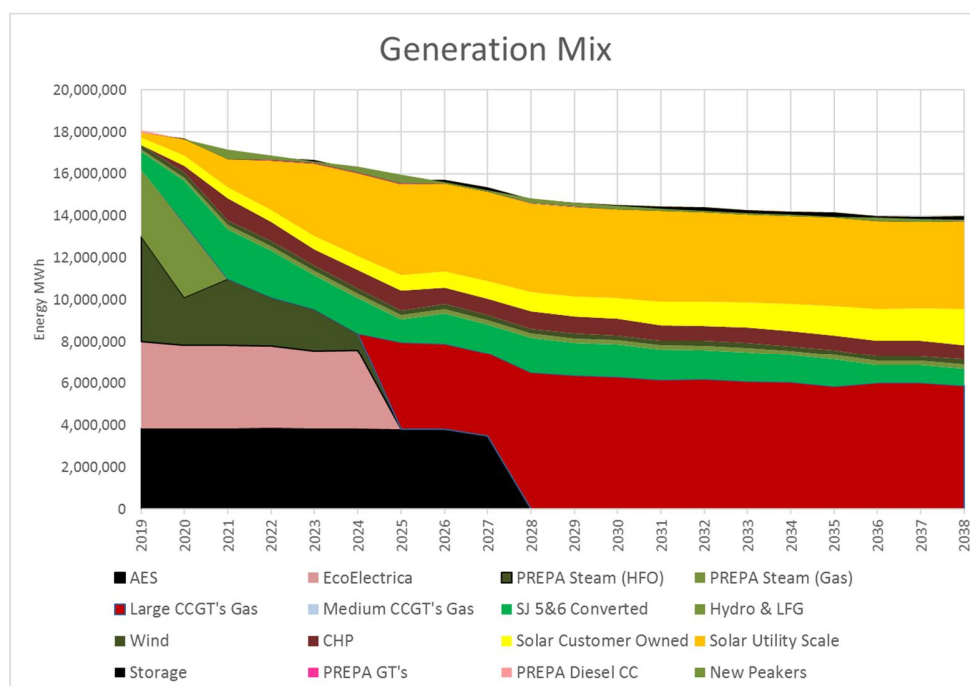
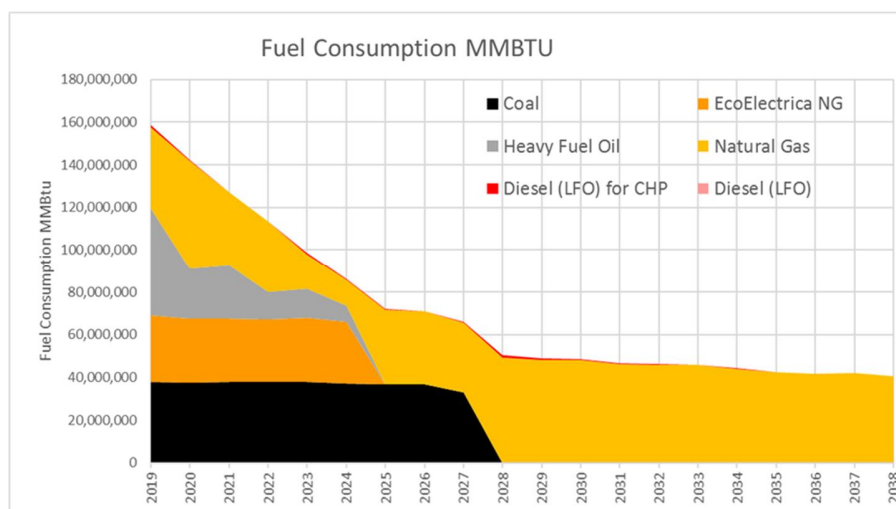


Exhibit 8-11: Scenario 4 Future Generation Production Mix

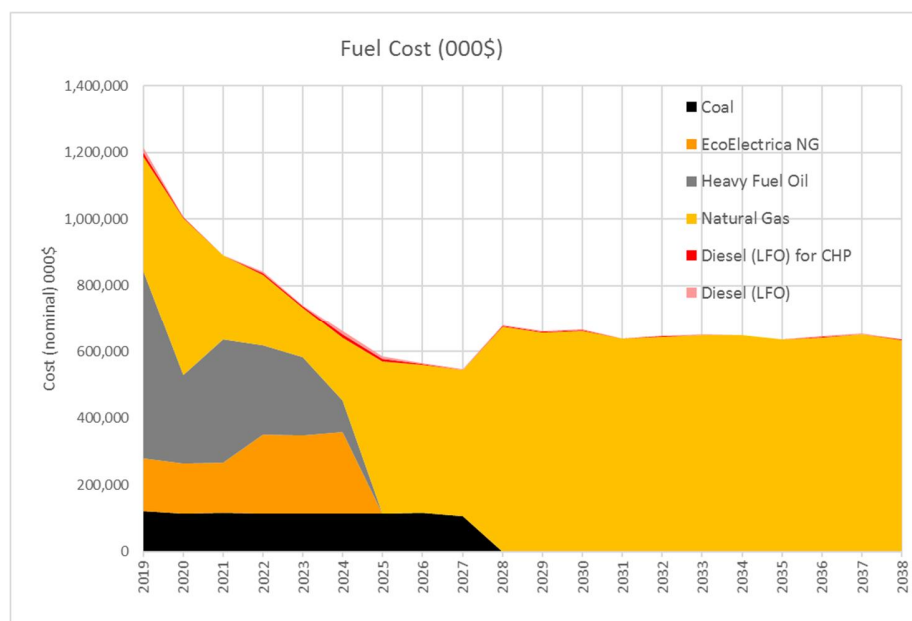
8.2.5 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines with the retirements EcoEléctrica in 2024, old gas and heavy fuel oil units and the peakers. Overall fuel consumption continues to fall through 2038 despite the new CCGTs in Palo Seco, Costa Sur and Mayagüez coming online in 2025-2028. Total fuel consumption drops 77% by 2038 with natural gas dominating this remaining fuel consumption.

Exhibit 8-12: Scenario 4 Fuel Consumption Trends

Fuel costs decline in line with the fall in fuel consumption to \$445 million by 2027 (55% below 2019 levels). Fuel costs increase in 2028 with the F-class CCGT built in Mayagüez, despite the retirement of AES in the same year. Fuel costs stay relative stable after 2028, on average at \$645 million in the last ten years of the study period.

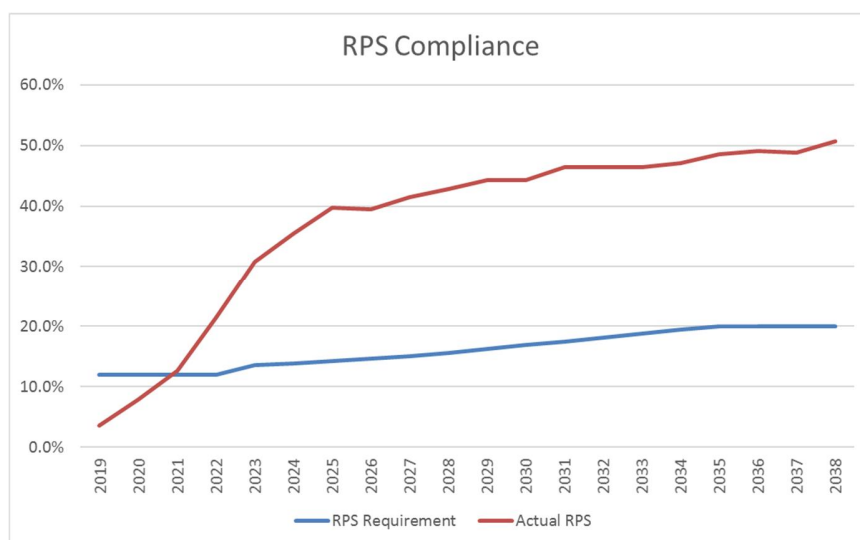
Exhibit 8-13: Scenario 4 Fuel Costs



8.2.6 RPS and Environmental Compliance

The Scenario 4 plan is MATS compliant after 2024 and achieves 51% RPS compliance by 2038 under the base case load forecast (57% under high load and 47% under low load growth).

The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met and exceeded in the Scenario 4 base case, as well as the high and low load cases and under all strategies. The plan achieved 51% renewable penetration by 2038, reaching proposed regulatory target than the 50% renewable generation by 2040 two years earlier than the target. Under the high load Scenario, 57% of all generation comes from renewables with 2,580 MW of solar installations, while in the low load Scenario 48% of all generation comes from renewables with 2,100 MW of solar installations. The base load case includes 2,220 MW of solar installations.

Exhibit 8-14: Renewable Portfolio Standards

CO₂ emissions for PREPA's fleet fall in the first ten years of the forecast driven by the retirement of the older fuel oil, diesel and gas units along with increased penetration of solar generation. Emissions fall 50% by 2027 and further 20% more in 2028 with AES coal retirement. Emissions continue falling in after 2028 reaching a 76% reduction by 2038. The emission rate for the fleet falls from 1,343 lbs./MWh in 2019 to 495 lbs./MWh in 2038. As expected the most efficient units, the CCGTs have the lowest emission rates at 820 lbs./MWh. San Juan units converted to natural gas also show lower emissions rates at around 850 lbs./MWh as well as EcoEléctrica prior to retirement. The unit with the highest CO₂ emission rates is AES coal at 2,155 lbs./MWh.

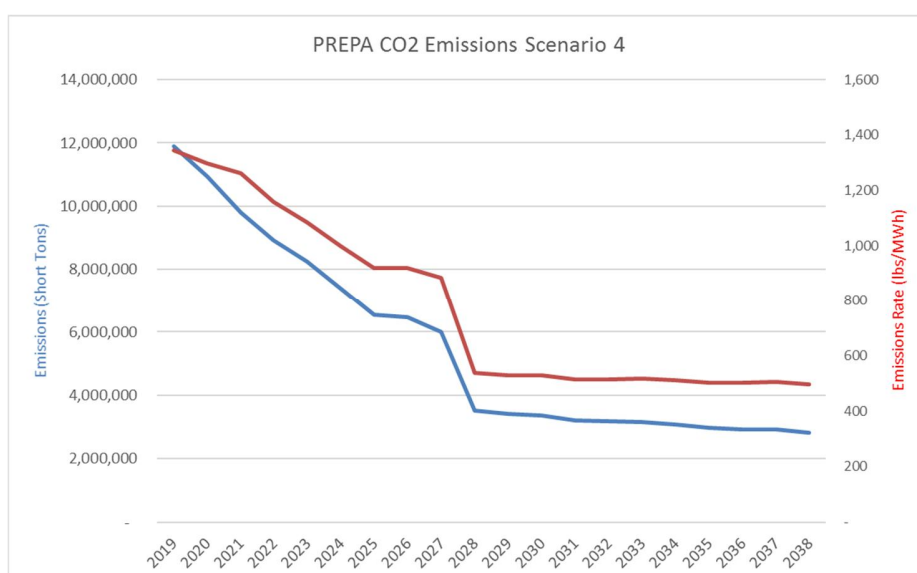
Exhibit 8-15: CO₂ Emissions PREPA System

Exhibit 8-16: CO2 Emissions by Unit Type

lb/MWh	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AES	2,154	2,155	2,154	2,154	2,154	2,155	2,155	2,155	2,155	-
EcoElectrica	876	876	876	877	879	881	-	-	-	-
Costa Sur 5&6	1,248	1,252	-	-	-	-	-	-	-	-
Existing Fleet (HFO)	1,426	1,721	1,666	1,664	1,690	1,660	-	-	-	-
Diesel CC (LFO)	93	-	1,335	1,335	1,335	1,335	1,334	1,335	1,335	1,335
Existing GTs (LFO)	1676	1759	0	1562	1611	1641	1488	0	0	0
SJ 5&6 With NG	857	852	851	850	849	850	849	851	850	851
New CCGT's	0	0	0	0	0	0	823	822	821	822
New Peaker gas	0	0	1200	1197	1206	1203	1202	1196	1194	1203
New Peaker diesel	0	0	2043	1894	1895	1799	1806	0	2043	1761
Total System	1,343	1,298	1,261	1,158	1,084	999	918	919	884	538

8.2.7 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from \$102/MWh in 2019 to \$90.5/MWh by 2027 (real \$2018), prior to AES Coal retirement, primarily due to the addition of solar and storage and the retirement of older generation. The costs increased in 2028, with AES retirement and the addition of the new CCGT, and then later decline due to falling fuel costs to reach \$93.1/MWh by 2038. Customer rates are expected to decline through 2027 under this plan.

The net present value of all operating costs reaches \$10.4 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is \$14.5 billion. Note that the 9% discount rate (6.86% on a real dollar basis), is the same discount rate used in the first IRP and it is based on the assumption that PREPA (or its successors) is able to resolve its current financial issues and can borrow the capital at this rate. It should not be confused with the WACC which the weighted cost of capital for private parties that are assumed to invest in the resource additions.

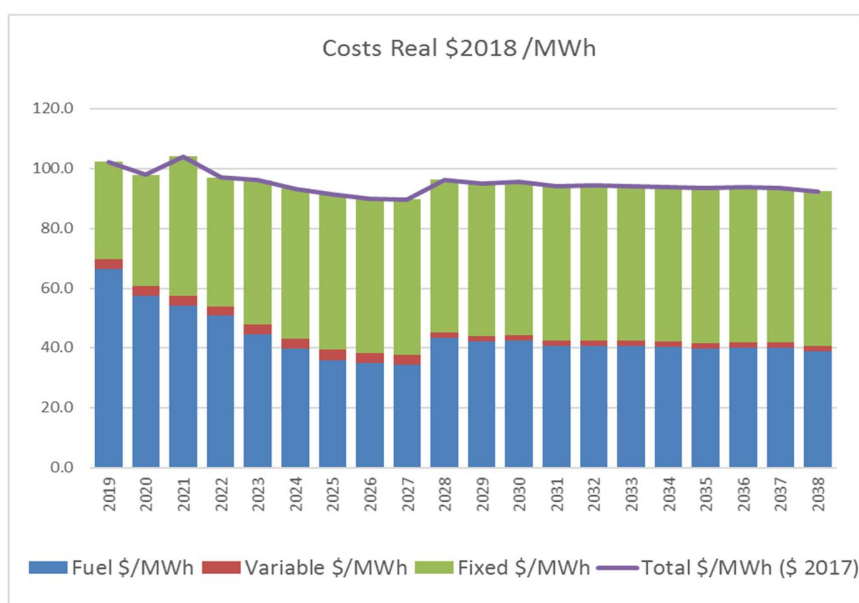
Exhibit 8-17: Scenario 4 Production Costs

Exhibit 8-18: System Costs High and Low Load Cases

Scenario	NPV @ 9% 2019-2038 \$Millions	Average 2019-2028 2018\$/MWh	NPV Deemed Energy Not Served MiniGrid Ops \$Millions	NPV + ENS \$Millions
Scenario 4 Base Load	15,195	96.3	228	15,423
Scenario 2 High load	16,995	99.0	169	17,164
Scenario 2 Low load	14,142	96.6	247	14,389

* Total system costs include generation, fuel, EE and regasification costs

Under the high load case, the production costs increase by \$2.7/MWh on average with an NPV of \$17.0 billion, \$1.8 billion higher than the base case. This is driven by an additional CCGT F-Class in San Juan build in 2029 to meet incremental loads in the north and a medium CCGT in Yabucoa in 2024. As discussed earlier, we are of the opinion that in the case the Strategy 3 expansion plan identified a better strategy.

Under the low load case, the average system costs are slightly higher compared to the base case but the overall NPV of the portfolio is lower at \$14.1 billion. The reduction in costs is mostly driven by not building the Mayagüez F-Class in 2028, under the low load case.

8.2.8 Resiliency (MiniGrid Considerations)

A critical component of the formulation of the 2018 Integrated Resource Plan (IRP) is the identification of electrical islands or “MiniGrid” into which the system may be segregated after a major atmospheric event (e.g. hurricane). In other words, the MiniGrids are regions of the system that are interconnected with the rest of the electric power system via lines that may take over a month to recover after a major event, and should be able to operate largely independently, with minimum disruption for the extended period of time that would take to recover full interconnection. In addition to the MiniGrids, there are also microgrids located within some of the MiniGrids that will be isolated from the MiniGrid after a major event. The methodology for the initial definition of the MiniGrids and Microgrids is described on Appendix 1.

The Siemens team evaluated the potential cost of energy not served in the case of a hurricane impacting the island and placing the system under a mini-grid operation for one month while the transmission network is repaired. This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of Scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impacted the island resulting in the operation of the MiniGrids for one month (“Deemed Energy Not Served”). The Deemed Energy Not Served was determined based on the total forecasted load at each MiniGrid, including critical, priority and balance, and the generation that would be available from thermal and renewable resources, complemented by storage. For the costs of energy not served we took into consideration that during grid isolated operation the load shedding will be on an announced and rotating basis and targeting loads where the impact would be the least (typically residential loads), with limited duration. The Siemens team used a value of \$ 2,000/MWh for costs of energy not served, about half of the lower expected cost for Puerto Rico (see Exhibit 7-22) and in line with the costs seen in another jurisdiction (see Exhibit 7-16).

As shown in Exhibit 8-20, the net present value of the overall portfolio costs under the base case would increase by \$228 million due to deemed energy not served. Under the high load case, the increase in portfolio costs is \$186 million, and in the low load case \$225 million. In the high case, the additional CCGT installations at San Juan and Yabucoa support mini-grid operation in these regions and reduce the overall potential costs of energy not served compared to the base case.

In Scenario 4, the critical and priority loads for the MiniGrid regions of Carolina, Caguas, Cayey, Arecibo, Mayagüez North and San Juan-Bayamon are not met with local generation while the plan is being developed in 2019 through 2022, as shown below for the Carolina MiniGrid. The total thermal maximum energy available including solar PV does not meet the critical, priority and balance loads through 2024 in Carolina (see Appendix 1 for more details on load generation balance and design of the MiniGrids).

Exhibit 8-19: Carolina Energy Coverage under a Minigrid Operation

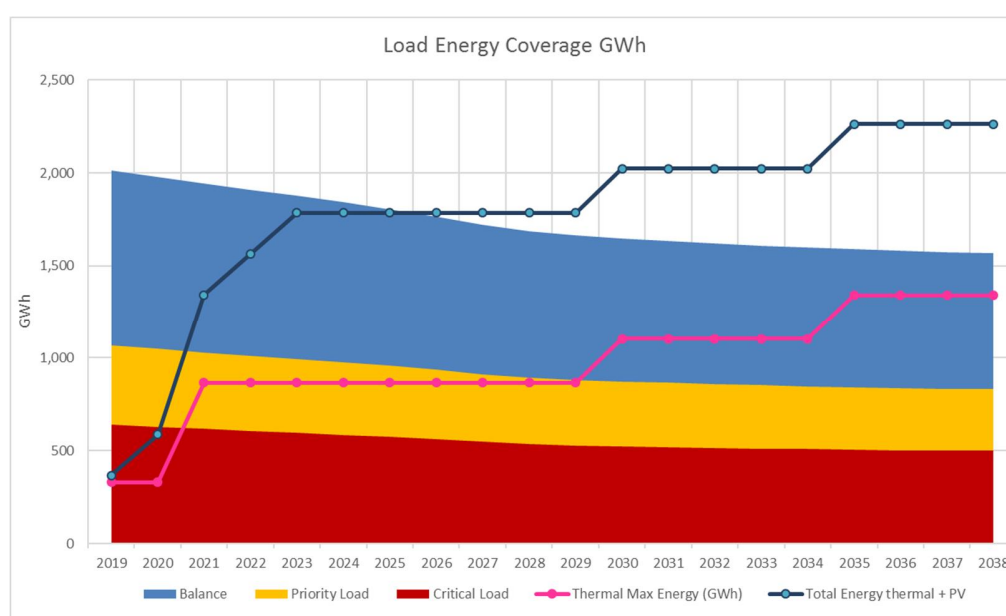


Exhibit 8-20 summarizes the present value of the cost of the “Deemed Energy Not Served” by MiniGrid region for Scenario 4 Strategy 2 and base load forecast.

Exhibit 8-20: Present Value of Cost of Deemed Energy Not Served by MiniGrids

MiniGrid	NPV Cost (\$000)
San Juan-Bayamon	\$ 8,874
Ponce	\$ -
Carolina	\$ 40,737
Caguas	\$ 127,850
Arecibo	\$ 25,110
Mayaguez-North	\$ 518
Mayaguez-South	\$ -
Cayey	\$ 25,196
Total	\$ 228,285

The largest potential costs are for Caguas and Carolina, followed by Arecibo and Cayey.

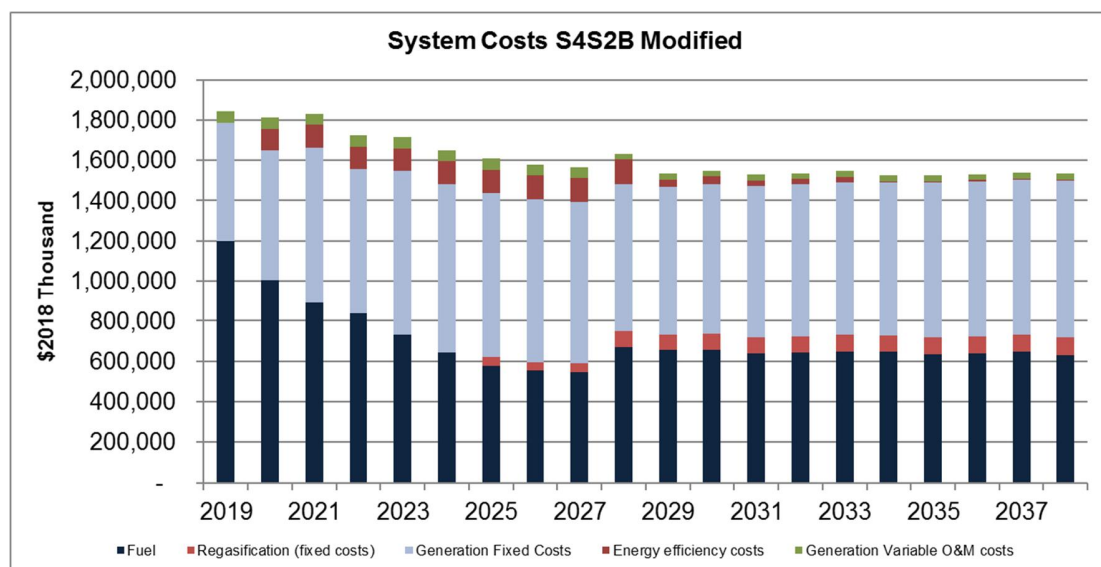
8.2.9 Scenario 4. Strategy 2 – Expert Review

The Siemens team performed an expert review of the results of Scenario 4 and recommended changes to the plan which we designated S4S2-Modified (or S4S2-M). The changes include replacing the two RICE 16 MW RICE units the plan calls for at Mayagüez with two 23 MW mobile peakers in Mayagüez North. In addition the single 21 MW LM2500 peaker the plan calls for at Carolina should be replaced with an additional 23 MW mobile peaker at the same location. The mobile peakers provide more flexibility at the mini-grid level for the Mayagüez North and Carolina regions. In addition, installing the same technology (mobile), rather than the three technologies that were called for in the original results, will provide benefits in the form of common maintenance practices, common spare parts inventory and the ability to relocate these units if needed in the future. The mobile peakers use containerized LNG as a fuel option. These are after the fact adjustments to the long-term capacity expansion plan developed by the Aurora model to make the Scenario 4 more a more practical plan for PREPA to implement and maintain.

In addition, the present value of the production costs resulting from these modifications are \$51.8 million lower than the pre-modified plan, with similar potential costs of energy not served at the minigrid level. The modified plan provides 15 MW more peaking capacity with 387 MW built by 2022 and 451 MW by 2038 in total. There is no significant change in emissions reductions, renewable curtailments or reserve margins through the study period.

Exhibit 8-21: System Costs Scenario 4 Modified

Case ID	NPV @ 9% 2019-2038 \$Millions	Average System Production Costs 2019-2028 2018\$/MWh	NPV Deemed Energy Not Served MiniGrid Ops \$Millions	NPV + ENS \$Millions	CO2 Emissions Reductions	Capital Investment Costs (\$ Millions)
S4S2B	15,195	96.3	228	15,423	76%	6,131
S4S2B-Modified	15,143	96.0	226	15,370	76%	6,132



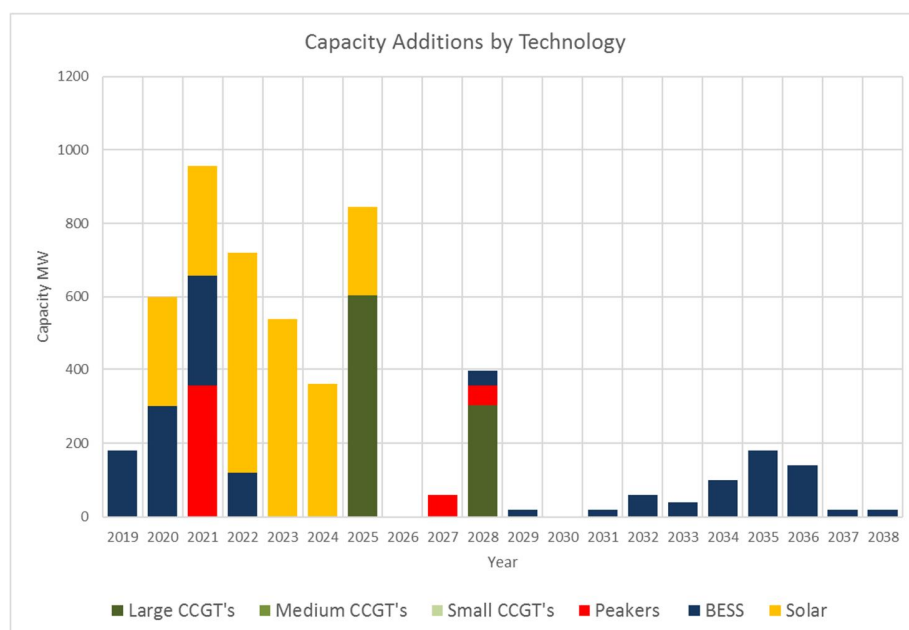
8.2.10 Considerations under Strategy 3

Under strategy 3, at least 50% of the peak demand needs to be supplied with local generation. Under this strategy, the economic simulation yields a very similar expansion plan to Strategy 2. However, this strategy provides less flexibility and resiliency at the mini-grid level and for this reason has higher potential costs from energy not served, in case of a major disruptive hurricane.

Under Strategy 3 and Base load forecast, the expansion plan is very similar with 1,200 MW of solar PV built in 2019-2022, maximizing the level of available solar PV capacity additions in this period. A total of 2,340 MW of solar PV is built during the study, only 120 MW higher than strategy 2 (see Exhibit 8-6).

There is 900 MW of battery storage built in 2019-2022 (in line with Strategy 2). In the long-term, there is an incremental 460 MW of battery storage built under this strategy. Two F-class CCGTs at Palo Seco and Costa Sur are built in 2025 along with an additional F-Class CCGT at Mayagüez, the same as Strategy 2. In addition, 388 MW of peakers are built in 2019-2022 (likewise Strategy 2) with 471 MW in total over the study period.

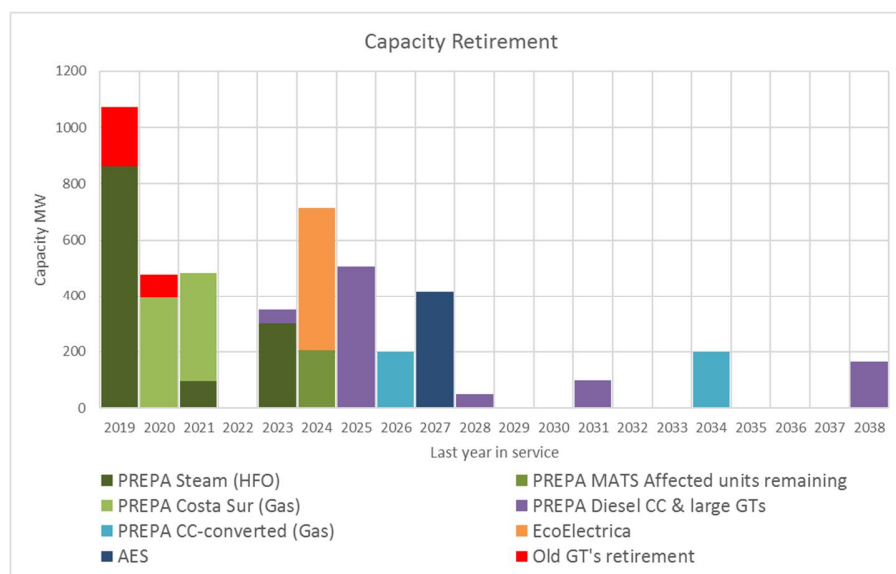
Under the high case, an additional F-Class CCGT at Yabucoa is built in 2025, the same for the low case but in 2028. This is the major difference with respect of Strategy 2. In the low case, the F-Class CCGT at Mayagüez is not built.

Exhibit 8-22: Capacity Additions Scenario 4, Strategy 3

Capacity by Technology MW		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Large CCGT's		0	0	0	0	0	0	604	0	0	302
Medium CCGT's		0	0	0	0	0	0	0	0	0	0
Small CCGT's		0	0	0	0	0	0	0	0	0	0
Peaking Generation		0	0	356	0	0	0	0	0	60	55
BESS		180	300	300	120	0	0	0	0	0	40
Total Distachable Additions		180	300	656	120	0	0	604	0	60	397
Solar		0	300	300	600	540	360	240	0	0	0
Total Additions		180	600	956	720	540	360	844	0	60	397

Retirements follow the same schedule of units retired as strategy 2, with the economic retirement of Aguirre ST 1 and 2 at the end of 2019, Palo Seco ST 3 and ST4 by the end of 2023 and 2024, respectively. San Juan units ST 7 & 8 are retired by the end of 2023 & 2021, respectively).

EcoEléctrica is economically retired by the end of 2024. Likewise, this retirement is triggered by the entry of a new CCGT at Costa Sur (F-Class) and happens irrespective of the load forecast. Costa Sur 5 & 6 last year in service is 2020 and 2021, respectively.

Exhibit 8-23: Capacity Retirements Scenario 4, Strategy 3 (last year in service)

Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PREPA Steam (HFO)	862	0	95	0	300	0	0	0	0	0
PREPA MATS Affected units remaining						206	0	0	0	0
PREPA Costa Sur (Gas)	0	393	388	0	0	0	0	0	0	0
PREPA Diesel CC & large GTs	0	0	0	0	50	0	506	0	0	50
PREPA CC-converted (Gas)	0	0	0	0	0	0	0	200	0	0
EcoElectrica	0	0	0	0	0	507	0	0	0	0
AES									416	0
Total Dependable Gen Retirement	862	393	483	0	350	713	506	200	416	50

Under this strategy, renewable penetration is slightly higher at 54% by 2038. Overall emissions decline over 70% by 2028, in line with strategy 2.

The overall portfolio costs are slightly higher under Strategy 3 at \$15.3 billion, 96 million higher than Strategy 2. Including the potential costs of energy not served under mini-grid operations, the overall costs of the portfolio is \$15.6 billion, at present value.

Exhibit 8-24: Comparison Portfolio Costs Scenario 4, Strategy 2 and 3 for Base Load

Scenario	NPV @ 9% 2019-2038 \$Millions	Average 2019- 2028 2018\$/MWh	NPV Deemed Energy Not Served MiniGrid Ops \$Millions	NPV + ENS \$Millions
Scenario 4 Strategy 2 Base Load	15,195	96.3	228	15,423
Scenario 4 Strategy 3 Base Load	15,290	96.4	343	15,633

At the regional MiniGrid level, the MiniGrids with the highest risk and potential costs of having load not served during a disruptive hurricane are San Juan-Bayamon and Caguas. As a

result, the present value cost of deemed energy not served is \$343 million, \$124 million higher than Strategy 2. For this reason, Strategy 2 provides a lower cost plan with higher resiliency and reliability at the mini-grid level.

Under the high load case, strategy 3 is a lower cost strategy compared to the high load case under strategy 2 without the development of an additional CCGT as San Juan in 2029, as shown under strategy 2. Thus, the overall portfolio cost is \$117 million lower, despite a greater potential cost from energy not served in the event a disruptive hurricane.

8.2.11 Considerations under Strategy 1

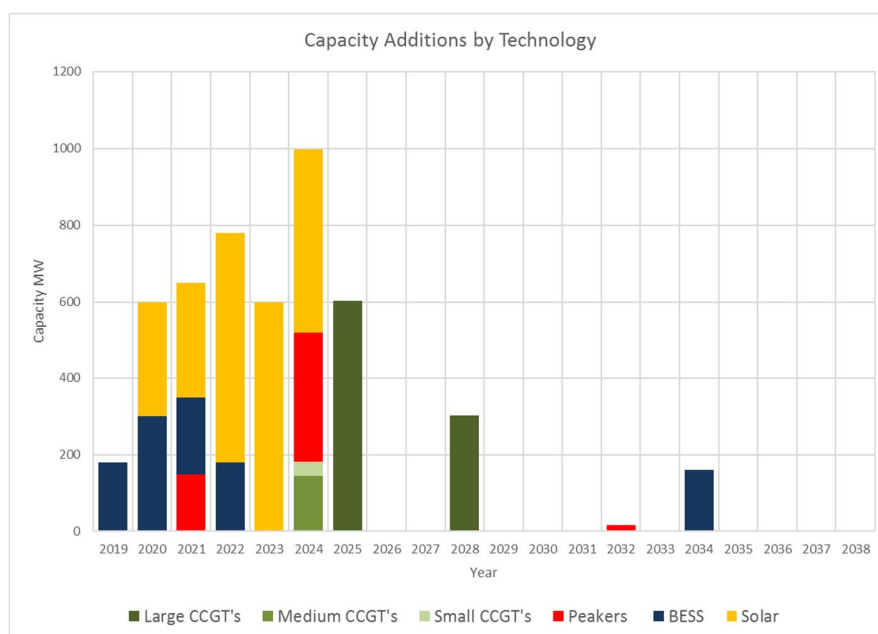
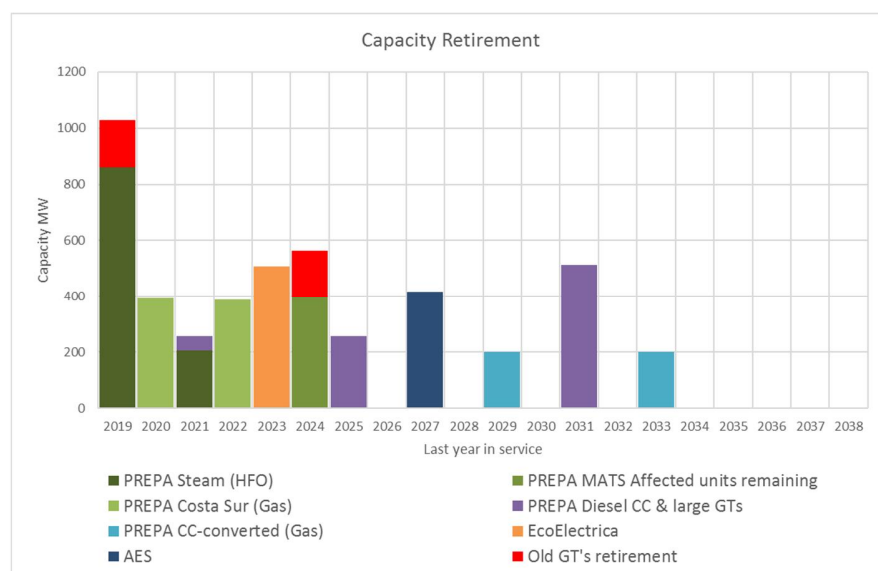
Strategy 1 is a centralized plan with no minimum generation requirements at the MiniGrid level. The Strategy produces an expansion plan that is slightly more expensive than strategy 2, which is Siemens' recommended plan, even before the cost of lack of resiliency is considered. A centralized plan has a greater risk and potential costs for unserved energy after a disruptive hurricane. The expansion plan is very similar to strategies 2 and 3 with more solar and battery storage generation (see Exhibit 8-6 S4S1B).

The expansion plan is very similar with 1,200 MW of solar PV build in 2019-2022, maximizing the level of available solar PV capacity additions in this period. A total of 2,340 MW of solar PV is built during the study period, only 120 MW higher than strategy 2.

There is 900 MW of battery storage build in 2019-2022 (in line with Strategy 2). In the long-term, there is an incremental 340 MW of battery storage build under this strategy. Two F-Class CCGTs at Palo Seco and Costa Sur are built in 2025 along with an additional F-Class at Mayagüez in 2028, in line with Strategy 2. In addition, 324 MW of peakers are built in 2019-2022 64 MW lower than Strategy 2 with 500 MW in total over the study period.

Retirements follow the same schedule of units retired as strategy 2, with the economic retirement of Aguirre ST 1 and 2 at the end of 2019, Palo Seco ST 3 and ST4 by the end of 2024 and 2021, respectively. San Juan units 7 and 8 units are retired by the end of 2024.

EcoEléctrica is economically retired by the end of 2023, a year earlier compared to Strategy 2. Likewise, this retirement is triggered by the entry of a large CCGT at Costa Sur (F-Class) in 2025. Costa Sur 5 & 6 last year in service is 2020 and 2022 as it could not compete with EcoEléctrica.

Exhibit 8-25: Capacity Additions Scenario 4, Strategy 1**Exhibit 8-26: Capacity Retirements Scenario 4, Strategy 1**

The overall portfolio costs are higher under this strategy driven by higher operating costs and potential costs from Deemed Energy Not Served under a mini grid operation in the event of a major hurricane. Portfolio costs are \$405 million higher, compared to strategy 2 and \$195 million higher, compared to strategy 3.

The potential for unserved energy arises in most MiniGrid regions, except for San Juan-Bayamon and Ponce. The regions with highest potential costs from unserved energy under MiniGrid operations are Carolina, Caguas and Arecibo.

Exhibit 8-27: Comparison Portfolio Costs Scenario 4 Strategy 2, 3 and 1

Scenario	NPV @ 9% 2019-2038 \$Millions	Average 2019- 2028 2018\$/MWh	NPV Deemed Energy Not Served MiniGrid Ops \$Millions	NPV + ENS \$Millions
Scenario 4 Strategy 2 Base Load	15,195	96.3	228	15,423
Scenario 4 Strategy 3 Base Load	15,290	96.4	343	15,633
Scenario 4 Strategy 1 Base Load	15,352	97.3	477	15,829

Under this strategy, the renewable portfolio standards are met with a 51% renewable generation by 2038.

8.2.12 Sensitivities Considerations

The Siemens team evaluated 4 sensitivities under Scenario 4 to isolate the impacts of certain important variables while holding other assumptions constant. For the 2018 IRP, four sensitivities were modeled.

Sensitivity 3: Economic retirement of AES Coal and EcoEléctrica regardless of contract term.

Under Sensitivity 3, AES is not retired on an economic basis and continues operating through 2038. The unit is a low-cost plant dispatching at \$76/MWh on average during the study period and capacity factors higher than 93%. With AES coal staying online, the CCGT at Mayagüez is not developed, as happens under strategies 2 and 3 in 2028.

EcoEléctrica retires at the end of 2024, in line with strategy 2 and 3 under base load. Under this sensitivity, the two F-Class CCGTs at Palo Seco and Costa Sur are also developed in 2025. Overall, there is over 2,160 MW of solar build supported by 1,020 MW of battery storage (see Exhibit 8-6 S4S2S3B).

Overall portfolio costs are \$275 million below the portfolio costs under the base case (strategy 2), driven by lower fuel, variable and capital costs. However, fuel consumption is 75% higher under this sensitivity with thermal generation accounting for 52% of total generation.

The renewable portfolio standards are met with 47% of total generation coming from renewables. However, there is an increase in curtailment levels reaching 5% by 2038, compared to 1%, under the base case, due to the inflexibilities of the AES coal plant.

Overall emissions are 93% higher compared to the base case with an overall emissions reduction of 54% by 2038.

Sensitivity 4: Ship-based LNG at San Juan is assumed to achieve permitting approval, but not the land based. The ship-based LNG at San Juan can basically supply the conversion of

San Juan 5 and 6 and provide limited gas to other developments. It has reduced capacity in comparison to the land-based LNG option.

Under Sensitivity 4, there is more gas generation added to the system. The Sensitivity installs, in addition to the CCGT's for the base case (S4S2), one additional F-Class CCGTs at Yabucoa in 2025 and the CCGT at Costa Sur in 2027. Solar and battery storage installations are slightly higher with 120 MW and 140 MW more, respectively by 2038 (see Exhibit 8-6 S4S2S4B).

With more availability of gas, the Aguirre CC2 stays online through the study period, as well the San Juan unit 5 conversion. San Juan 6 retires in 2035 as in the base case.

Overall portfolio costs are about 93.0 million higher under this sensitivity, driven by higher CapEx and fuel costs. This case also has higher potential costs from unserved energy during a hurricane event.

Sensitivity 5: High gas prices.

As in the base case, both the F-Class at Palo Seco and Costa Sur are found economic to be in place in 2025. Under this sensitivity, the simulation favors the development of 393 MW of additional gas-fired peakers (90% more), in addition to a medium CCGT at Yabucoa. The medium CCGT is developed, instead of a large CCGT at Mayagüez. Solar and battery storage installations are similar to the base case (see Exhibit 8-6 S4S2S5B).

Under a high gas price Scenario, EcoEléctrica stays online through the study period. Both of Aguirre CCs are retired as well as both of San Juan converted units, the last of which retires in 2036. AES is scheduled to be retired in 2027 but if it would not under a high gas price Scenario, the economics will be more robust.

Overall portfolio costs are \$1 billion higher under a high gas price Scenario at \$16.2 billion over the study period (at present value). The increase is driven by higher fuel costs, the continuation of EcoEléctrica and capital payments with the development of more peakers. The risk to the portfolio from higher gas prices is significant.

Sensitivity 6: High cost of renewables

Under this sensitivity, there is a significant reduction in solar installations with only 780 MW of solar PV installed over the study period, 1,400 MW below the base case. Batteries to support the solar developments are reduced as well by 460 MW to 620 MW in total. The RPS targets are met through 2035 but the plan will fall short of the proposed long-term target of 50% by 2040 reaching only 22% renewable penetration by 2038 (compliance with current regulations is achieved). CO2 emissions in this case are 38% higher compared to the base case by 2038 with overall emissions reductions falling by 67% over the study period.

There is more gas capacity installed with 1,200 MW of new large CCGTs installed, including an F-Class at Mayagüez in 2025 (3 years earlier than the base case) and an F-Class in San Juan in 2028 (installation only seen in high load cases). In addition, there is a medium CCGT developed in Yabucoa in 2024 (see Exhibit 8-6 S4S6S6B).

Overall portfolio costs are \$1 billion higher compared to the base case, mostly driven by \$1.1 billion more in fuel costs and capital expenditures, partially offset by lower variable and fixed

costs. The potential costs from energy not served under MiniGrid operation is lower by \$62 million, compared to the base case with more gas available locally in some regions.

Exhibit 8-28: Scenario 4, Sensitivity 6 System Costs

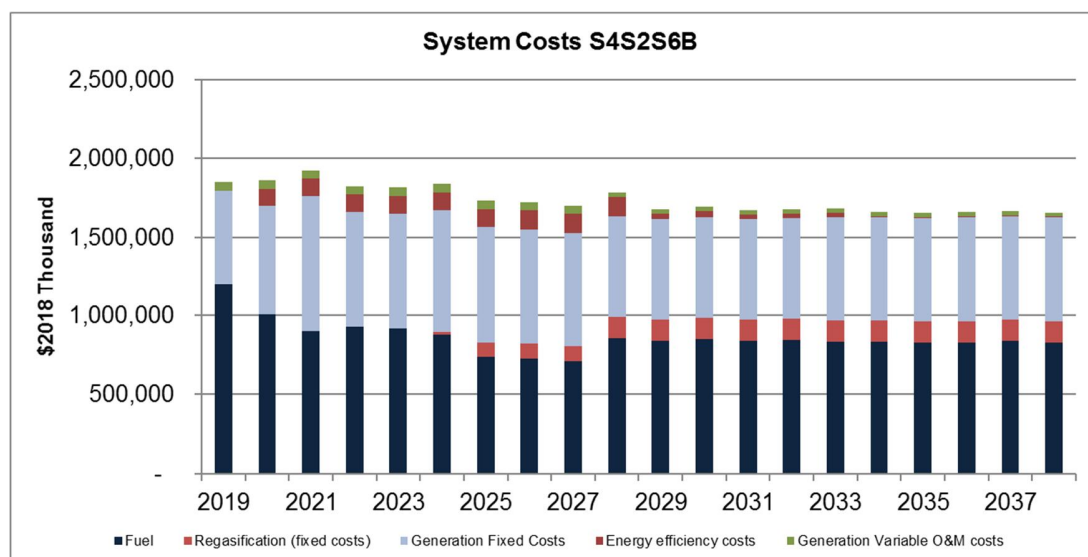


Exhibit 8-29: Comparison Portfolio Costs Scenario 4 Sensitivities

Scenario	NPV @ 9% 2019-2038 \$Millions	Average 2019- 2028 2018\$/MWh	NPV Deemed Energy Not Served MiniGrid Ops \$Millions	NPV + ENS \$Millions
Scenario 4 Strategy 2 Base Load	15,195	96.3	228	15,423
Sensitivity 3	14,919	95.1	263	15,182
Sensitivity 4	15,288	96.4	483	15,771
Sensitivity 5	16,267	101.8	196	16,463
Sensitivity 6	16,203	101.7	166	16,369

* System costs includes generation costs, EE programs, fuel and regasification costs

8.2.13 Rate Impact

In the sections above, we presented the composition of least cost portfolio formulated under Scenario 4. In this section we estimate the potential impact of the S4S2B portfolio on the final rates to customers and compare the resulting final rates with the possible costs that the

customers would incur for self-supply as described in Appendix 4 Demand-Side Resources and that basically include:

- a) Residential Solar Photo-Voltaic (PV), use of net-metering
- b) Grid-Defection; PV plus storage at levels that allowing become an autonomous self-supplier.
- c) Combined Heat and Power (CHP)
- d) Diesel Generator

8.2.13.1 Rate Components

We provide below a high-level description of the individual components that make up the final rates resulting from the S4S2 generation portfolio.

The final customer rate can be broken down into at least three basic components:

- a) Generation cost of energy delivered to the customers (generation)
- b) Non-generation utility component (transmission & distribution)
- c) Balance non-bypassable component (charges for legacy liabilities)

The generation rate component is directly dependent upon the Capital, Fixed Operating and Maintenance (FO&M), Regasification, Fuel, and Variable Operating and Maintenance (VO&M) costs incurred in building and operating the generation portfolio. This component is portfolio specific and will change as the generation asset mix changes. Also, this rate reflects the total generation needed to serve the customer load accounting for the technical and non-technical losses in the transmission and distribution network and PREPA's internal self-consumption. The Portfolio includes a certain amount of customer self-supply and the total generation is reduced by this self-supply for the purposes of calculating the costs.

The non-generation utility component is PREPA's Non-Fuel and Power Purchase (non-F&PP) rate less the non-bypassable component included in the non-F&PP rate. This component reflects the transmission and distribution costs and is held constant across generation portfolios and was provided by PREPA's advisors for this analysis; it has an average value of nominal 14.2 cents per kWh for the next 10 years and considers the reduction in load and energy efficiency effects.

Finally, the third basic component is PREPA's Non-Bypassable Non-F&PP rate that reflects PREPA's charges for legacy liabilities such as pension and debt. The amount included is approximately 3 cents per kWh for debt service and 2 cents per kWh for pension funding in \$2018 terms (6.2 cents per kWh nominal average for the next 10 years considering the reduction in load and energy efficiency effects). This component is static and does not change with the portfolio asset mix.

The final resulting rate for the case is computed as the sum of the three individual components described above and is then compared with the cost of customer-based alternatives.

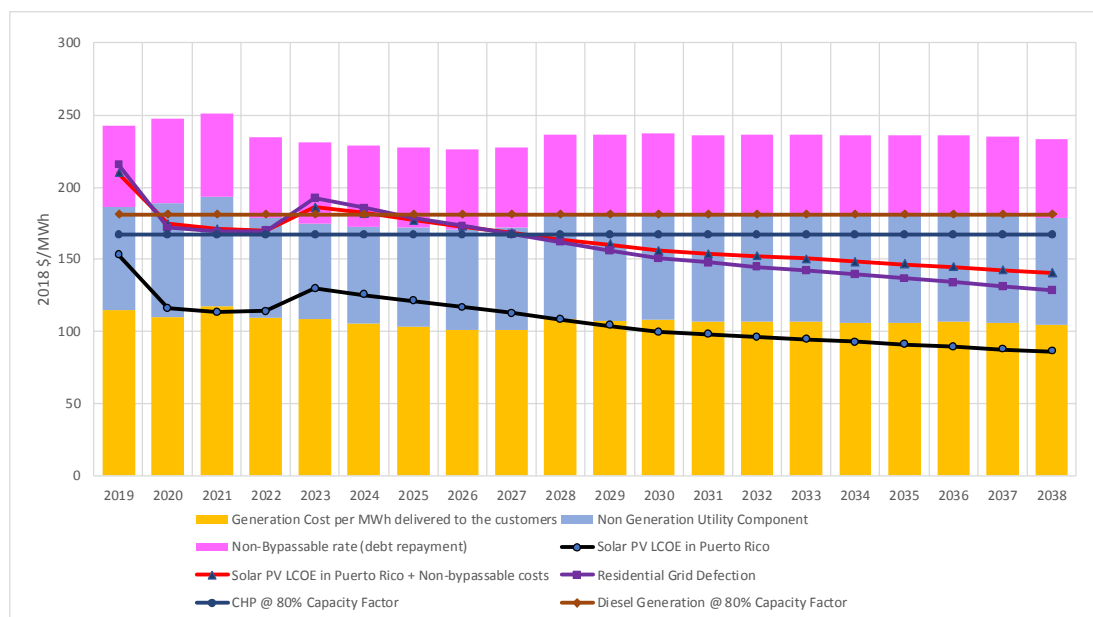
8.2.13.2 Results of Comparison to Customer Based Alternatives

In this section we describe the results of the analysis we performed comparing the final S4S2 rates to unit costs for customer-based alternatives.

From the results, which are illustrated in Exhibit 8-30, we have the following observations and inferences:

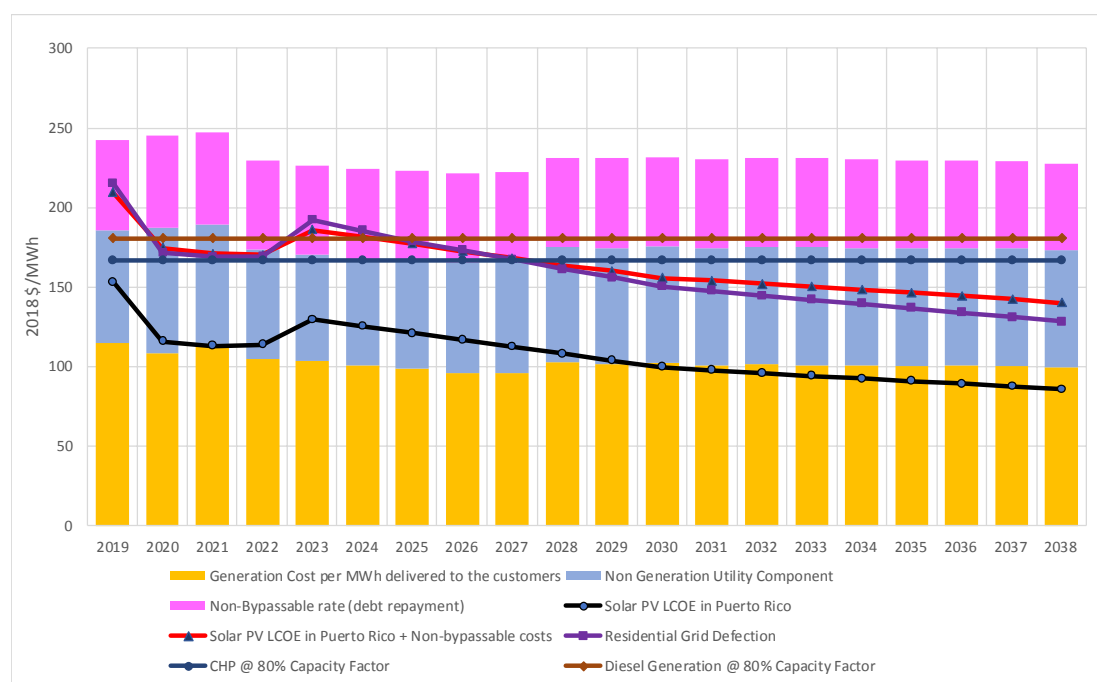
- The unit costs for all the customer alternatives considered are lower than the final all-in S4S2 generation portfolio rate.
- The levelized cost of customer owned generation is higher than the cost of the utility generation delivered to the customer (that includes the effect of losses), until 2028 (when AES Coal retires). However, this cost of customer owned generation is significantly lower than the total rate even before the non-bypassable component is added and confirms the assumption in the DG forecast that the continuance of 'net-metering' rates will foment customer side roof top PV concurrent with the high adoption rates observed to date.
- These results also indicate that, given PREPA's forecasted non-bypassable rate component, coupled with the expected reduction in renewable generation costs, customers may be motivated to self-supply if they are able to raise the capital investment required for installing the self-supply option or if a developer installs the equipment and recovers the investment through leases or other financing options.
- It is also interesting to note that when the Non-Bypassable charge is added to the case where the customer only has PV and uses PREPA as a bank (net-metering) the costs are very similar to the complete self-supply option. However, in this case there is an added advantage of no need for the initial capital outlay. So, provided that the PREPA service meets the reliability expectations of the customer, it can be reasonably concluded that the customer will continue to be connected to the PREPA grid.

Exhibit 8-30: Final S4S2 Generation Portfolio Rates Compared to Unit Costs of Customer Alternatives



We analyzed another case where we reduced the non-technical losses to typical values observed in the US (0.5% or less). The resulting final rate for the S4S2 generation portfolio, also reduces, but not to the extent that our observations and inferences discussed above change. This updated comparison chart is given in the exhibit below.

Exhibit8-31: Final S4S2 Generation Portfolio Rates Assuming Reduced Losses



8.2.14 Nodal Analysis Scenario 4, Strategy 2

The Siemens team evaluated the least cost plan under Scenario 4 using a nodal simulation. The objective is to identify the effects of transmission on the key metrics of technical losses, production costs, renewable curtailment and energy not served.

The results of the nodal runs show that in the first 10 years (2019 – 2028) the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment (see Exhibit 8-32). The losses in each of the nodal cases was less than that of the zonal runs used, due to the more accurate modeling of the transmission system. On average the reduction in losses is 0.8% as shown in Exhibit 8-33.

The amount of curtailment observed for the new solar generation was higher in the Nodal runs towards the end of the model period as shown in Exhibit 8-32, but this was found to be not related with transmission but rather with differences in the strategies for the dispatch of the storage used in the nodal runs.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

Exhibit 8-32: Production Costs Nodal vs. Zonal and Renewable Curtailment

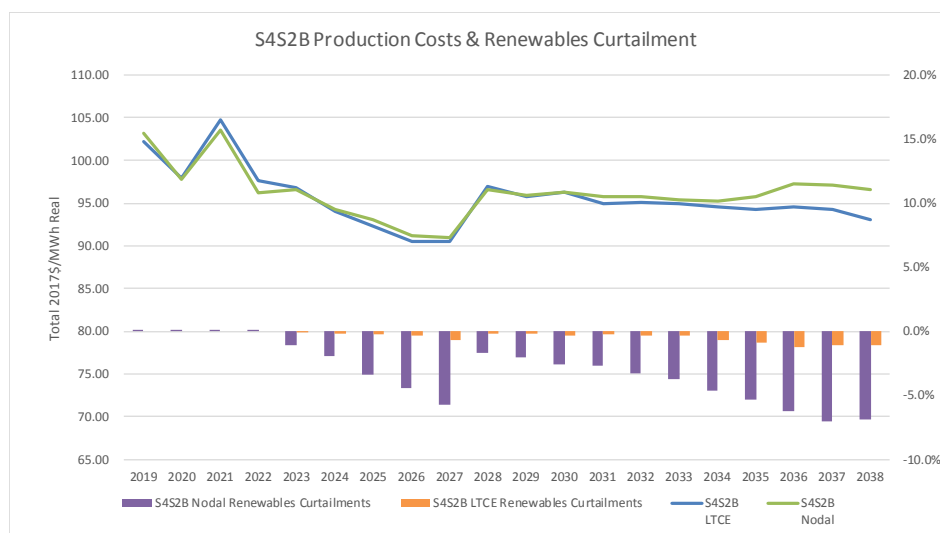


Exhibit 8-33: Transmission Losses Differences

Loss Difference	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
LTCE Losses	3.8%	3.2%	1.9%	1.9%	1.9%	2.0%	1.4%	1.4%	1.4%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.7%	0.8%	0.7%
NODAL Losses	1.1%	1.0%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
DIFFERENCE	2.6%	2.2%	1.3%	1.3%	1.3%	1.4%	1.0%	0.9%	0.9%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.2%

8.2.15 Nodal Analysis Scenario 4, Sensitivity 6

The Siemens team evaluated the least cost plan for sensitivity 6 using a nodal simulation. The objective is to evaluate potential areas of maximum stresses of the system including transmission constraints, solar curtailments and heavier use of the transmission facilities. The Siemens team used four metrics to evaluate the impact, including losses, generation, production costs and curtailments.

The results of the nodal runs show that in the twenty year (2019 – 2038) the production costs of the nodal runs match very closely with the LTCE runs. The losses in each of the nodal cases was less than that shown in the LTCE cases resulting in slightly lower peak load than in the LTCE cases. Losses are lower in the nodal simulation because of the direct use of the transmission grid parameters in the model. On average the reduction in losses is 0.8%. The difference in losses observed is higher in the first ten years (2019 – 2027) averaging 1.4% below the zonal simulation. From 2028 – 2038 the difference is about 0.3% (below in the nodal case). As a result, we may conclude that generation is serving a lower demand in the nodal simulation than in the zonal simulation.

The energy demand was unchanged. The transmission losses in the Nodal run are determined by the transmission model.

From a transmission point of view there were no binding constraints of the transmission system in the nodal runs.

The installed battery to solar ratio benefits the efficiency of the storage system as well as the level of curtailment of solar.

Exhibit 8-34: Production Costs Nodal vs. Zonal and Renewable Curtailment

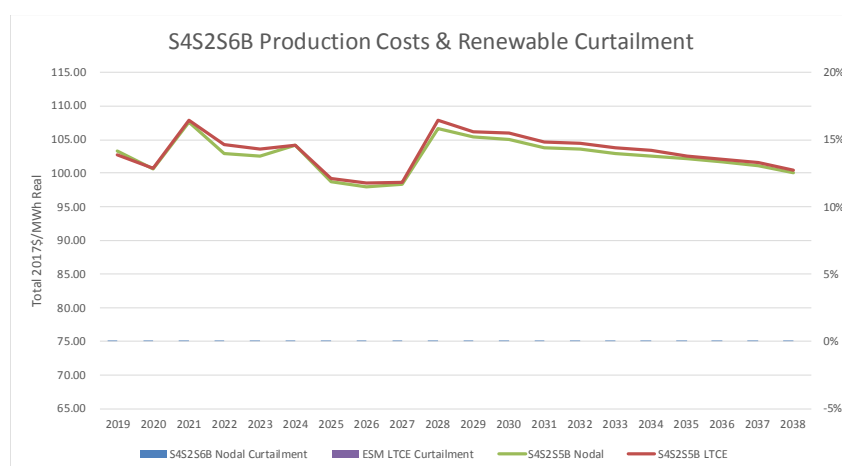


Exhibit 8-35: Transmission Losses Differences

Loss Difference	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
LTCE Losses	3.8%	3.2%	2.5%	1.9%	2.0%	2.1%	1.6%	1.5%	1.5%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%
NODAL Losses	1.1%	1.0%	0.8%	0.6%	0.6%	0.7%	0.5%	0.5%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
DIFFERENCE	2.6%	2.2%	1.8%	1.3%	1.4%	1.4%	1.1%	1.0%	0.9%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

8.3 The ESM Plan

The Energy System Modernization Plan (ESM) is a plan developed by PREPA based on several generation expansion additions. The purpose of the ESM Plan is to expedite the implementation of a preferred plan utilizing procurement options presented by the Public Private Partnership Authority, identify the pricing structure necessary to retain existing natural-gas fired generation in the south, consider locational alternatives for new large scale CCGTs, and ensure reliable capacity in the San Juan area. The corresponding least cost long term capacity expansion plan (LTCE) is developed taking into consideration some pre-defined decisions as described below. Siemens compared the ESM plan to the applicable least cost plan (Scenario 4, strategy 2) under base load forecast.

The ESM is based on the following fixed decisions:

- Replace all 18 existing Frame 5 GT's at optimized locations with new mobile units GTs (23 MW each) or equivalent, as a fixed decision to come online by 2021 and with containerized LNG as a fuel option (418 MW total).
- Develop an LNG terminal at Yabucoa (Caguas) and a 302 MW F-Class CCGT in June 2025 to be built as a fixed decision.
- Develop an F-Class CCGT at Palo Seco by 2025 fueled by a land-based LNG at San Juan
- Develop new ship-based LNG at Mayagüez and conversion to dual fuel of the Aero Mayagüez units (4x50MW) as a fixed decision. In addition, as an option, the case includes the possibility of building a 302 MW F-Class CCGT at Mayagüez . The last option was not selected by the LTCE.
- Develop a new 114 MW thermal plant (combined cycle assumed 3x38 MW) burning natural gas or LPG in the San Juan area. The actual technology to be used will be determined via an RFP process and the modeled plant is not prescriptive and only a conservative assumption.

The following assumptions were also included in the simulation of this Scenario:

- Load Forecast is treated via a Base, High and Low case.
- EcoEléctrica is assumed to stay in service but with the fixed payment reduced to 60% (new 2022 payment \$88 million down from \$240 million the prior year). This reduction is enough for it to be competitive with the CCGT option. The unit is assumed to be fully flexible for cycling.
- AES is assumed to expire in 2027, in line with the least cost plan.
- Solar and storage costs and availability based on reference case assumptions. Solar PV addition is limited to 240 MW in 2021, 480 MW in 2022-2023, 300 MW in 2024 and 480 MW after 2024. Storage addition is limited to 20 MW in 2019, 100 MW in 2021 and 160 MW onwards.
- San Juan units 5 & 6 are converted to natural gas in June 2019 (in line with the least cost plan). San Juan units are subjected to a capacity payment of \$5 million per unit until 06/30/2024, on an annual basis. Afterwards, the capacity payment is zero. San Juan units are subjected to fuel constraints at San Juan (ship-based fuel constraint

for July 2019–June 2025, and land-based LNG constraint from July 2024 through the end of the planning period.

- Energy Efficiency is assumed to meet the requirement of Regulation No. 9021, i.e., 2% per year of incremental savings attributable to new energy efficiency programs for 10 years.
- Minimum RPS targets of 12% by 2022, 15% by 2027 and 20% by 2035.

8.3.1 Generating Additions

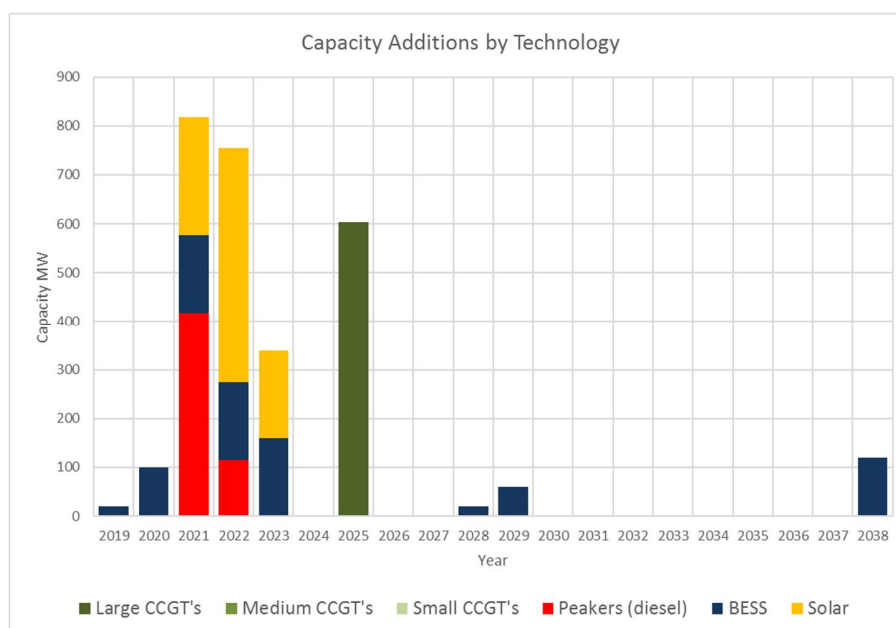
The economic simulation of the ESM case results in 900 MW of utility scale PV additions over the planning period, 1,320 MW below Scenario 4. Most of solar PV installations happen in 2020–2022, with 720 MW installed (in line with the maximum annual limits set for the ESM case). Under the high demand case, 1,680 MW of solar PV is installed over the study period, with the incremental load primarily supplied from 780 MW of additional solar PV. There is no change in terms of solar PV additions in the 2020–2022 period, as the predefined maximum levels are installed. In contrast, under the low demand case 720 MW of solar PV is installed (180 MW less than the base case), with all the PV installed in the 2020–2022 period.

800 MW of battery energy storage is built over the planning period, about one half of the total is installed in 2019–2022. The ratio of solar PV to battery storage is much higher in the ESM case compared to the least cost plan under Scenario 4 (0.88 MW per 1 MW of solar in ESM vs. 0.4 MW per 1 MW in the least cost plan). A similar amount of battery storage is installed under the high demand case. Under the low demand case 640 MW of battery storage is installed by 2038, 160 MW less than the base load.

The thermal additions are largely the ones identified as an input to the plan, with the exception of a medium diesel CCGT (141 MW) installed in Ponce East by 2035. The plan does not develop a new CCGT at Costa Sur, due to the assumed continued operation of EcoEléctrica. Under the high demand case, the medium diesel CCGT at Ponce East is not installed but instead a small 29 MW gas-fired CCGT in San Juan is installed and two diesel peakers (39 MW each) at Carolina and CAYMG are installed. Other thermal additions are the same as the base case, including the mobile gas-fired peaking capacity and Mayagüez conversions in the South. Overall, there is a net reduction in fast ramping capacity of 63 MW in the high demand case⁶⁰. Under the low demand case, a small CCGT in Ponce is built instead of the medium diesel CCGT in the base case with a net reduction of fast ramping capacity of 113 MW.

The mobile peakers provide MiniGrid resiliency, in particular for Carolina, Caguas, Cayey, Ponce (Jobos) and Mayagüez North.

⁶⁰ The amount of battery and gas-fired peaking capacity to support over 1,600 MW of solar PV under the high demand case may need further refinement.

Exhibit 8-36: ESM Plan Capacity Additions

Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Large CCGT's	0	0	0	0	0	0	604	0	0	0	0
Medium CCGT's	0	0	0	0	0	0	0	0	0	0	0
Small CCGT's (LPG enabled)	0	0	0	114	0	0	0	0	0	0	0
Peakers (diesel) CT's and CCGTs	0	0	418	0	0	0	0	0	0	0	0
BESS	20	100	160	160	160	0	0	0	0	20	60
Total Distachable Additions	20	100	578	274	160	0	604	0	0	20	60
Solar	0	0	240	480	180	0	0	0	0	0	0
Total Additions	20	100	818	754	340	0	604	0	0	20	60

8.3.2 Capacity Retirements

The installation of the PV and Storage in 2020 allows for the economic retirement of Aguirre ST 1 and 2 (end of 2019 & 2020), Palo Seco ST 3 & 4 in 2024 and San Juan ST 7 & 8 in 2023.

EcoEléctrica is modelled to remain in service with an adjustment to the contract that was defined to be competitive with a CCGT. The fixed payments are reduced to about 40% of current values and the unit is assumed to be able to cycle as required to accommodate the renewable generation production variations. This reductions were determined to make EcoEléctrica competitive with the CCGT.

Costa Sur 5 & 6 last year in service are 2021 and 2020, respectively, retired by the fall in load and the entry of solar PV and Storage.

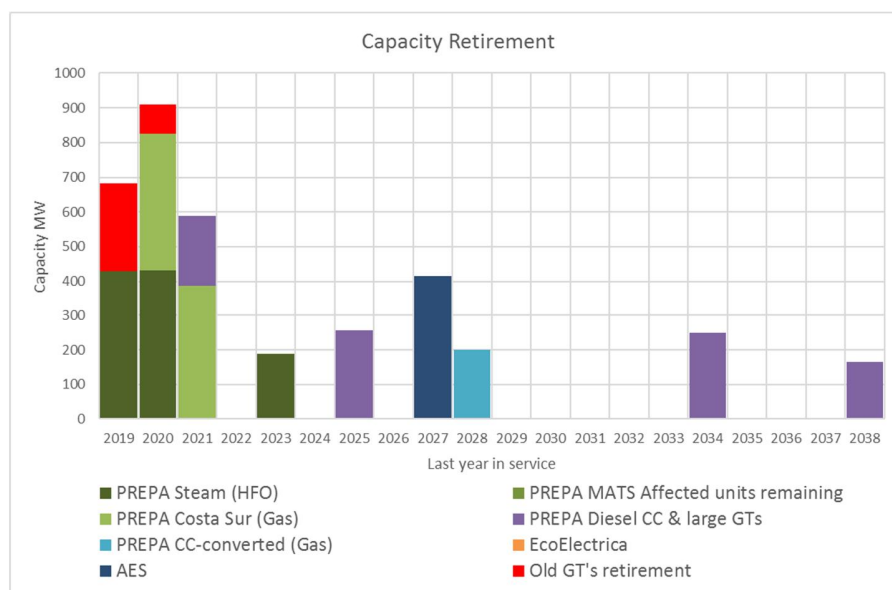
AES is retired at the end of 2027, not economically but by defined model input.

The Aguirre CCGT unit 1 is retired in 2025 and unit 2 later in 2034. Under the high demand case, Aguirre CCGT unit 2 is not retired and stay online through the study period. Under the low demand case there is no change in capacity retirements or their timing.

The four units of Aero Mayagüez are converted to gas by 2022 and stay online through the planning period. The Cambalache units stay online for reserves and MiniGrid support.

Finally, the natural gas converted San Juan 5 stays online through the planning period, while San Juan 6 is retired in 2028.

Exhibit 8-37: ESM Capacity Retirements (last year in service shown)



Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PREPA Steam (HFO)	429	432	0	0	189	0	0	0	0	0	0
PREPA MATS Affected units remaining						0	0	0	0	0	0
PREPA Costa Sur (Gas)	0	393	388	0	0	0	0	0	0	0	0
PREPA Diesel CC & large GTs	0	0	200	0	0	0	257	0	0	0	0
PREPA CC-converted (Gas)	0	0	0	0	0	0	0	0	0	200	0
EcoElectrica	0	0	0	0	0	0	0	0	0	0	0
AES									416	0	0
Total Dependable Gen Retirement	429	826	588	0	189	0	257	0	416	200	0

8.3.3 Future Generation Mix and Reserves

During the planning, under the ESM portfolio, the system moves away primarily from coal and oil to natural gas, renewables and energy storage. By 2038, 53% of the installed capacity in the system consists of renewable generation or facilities in place for its integration (battery storage). This number includes customer driven distributed solar. However, total renewable generation is only 24% of the total compared to 49% in the S4S2 plan (see Exhibit 8-39). Most of the gas generation comes from the two new large CCGTs and EcoEléctrica. As such, the development of the LNG terminals is critical for the feasibility of the new gas units. As PREPA's units and the thermal PPOA's are phased out, the operating reserves decline from 73% in 2019 to a low of 51% by 2029 with the retirement of AES coal. Operating reserves rise gradually afterwards driven by the decline in load and the medium diesel CCGT. The Planning Reserve Margin was not found to be binding at any time on the LTCE decisions.

Exhibit 8-38: ESM Future Installed Capacity Mix

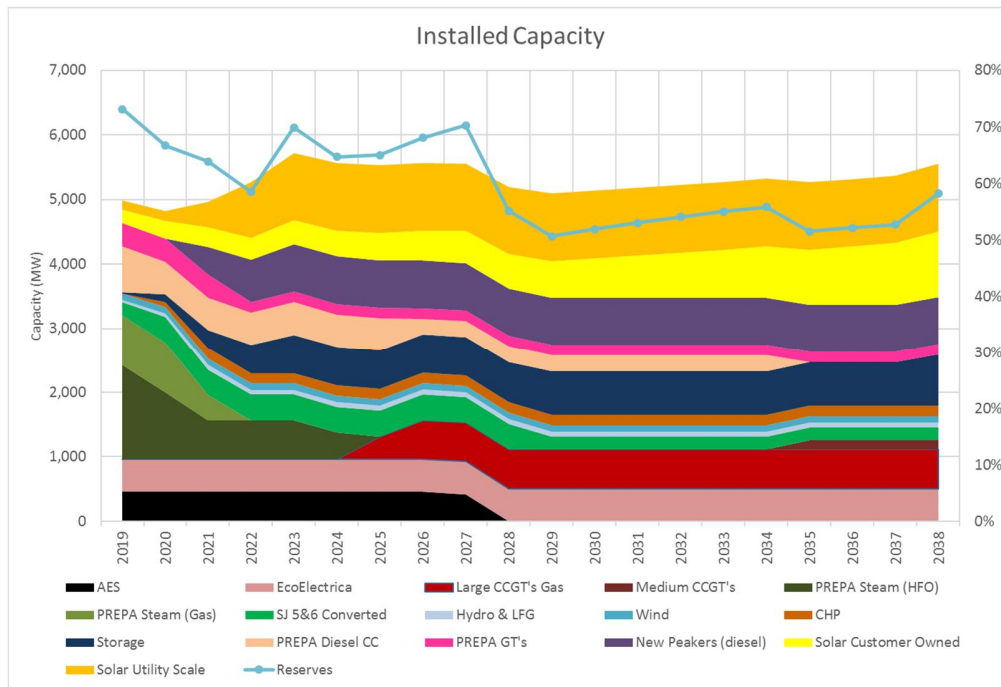
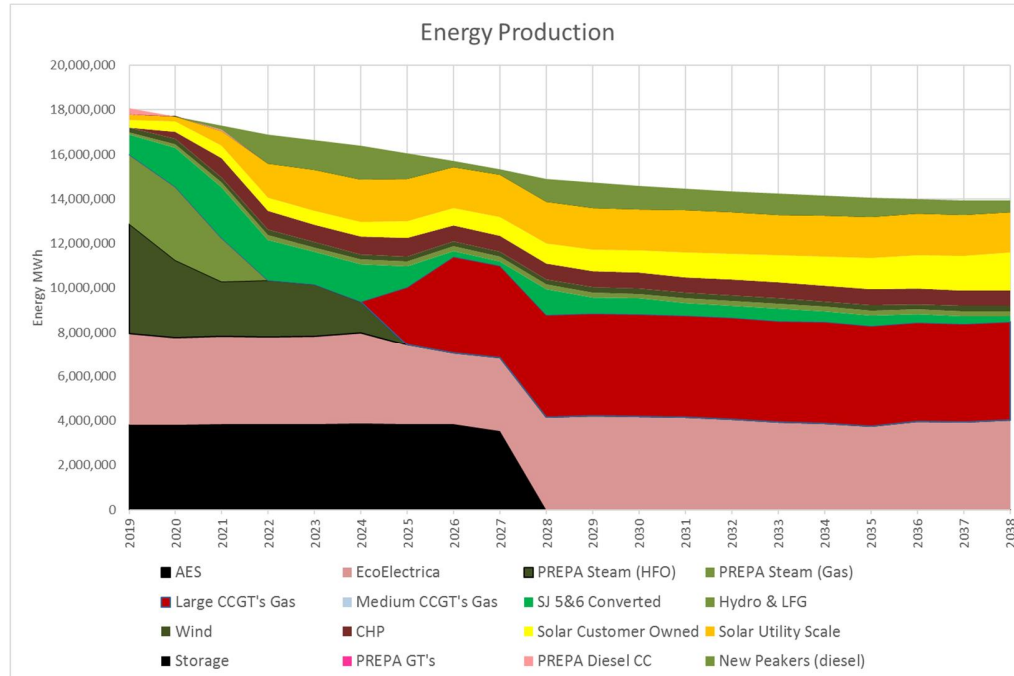


Exhibit 8-39: ESM Future Generation Mix

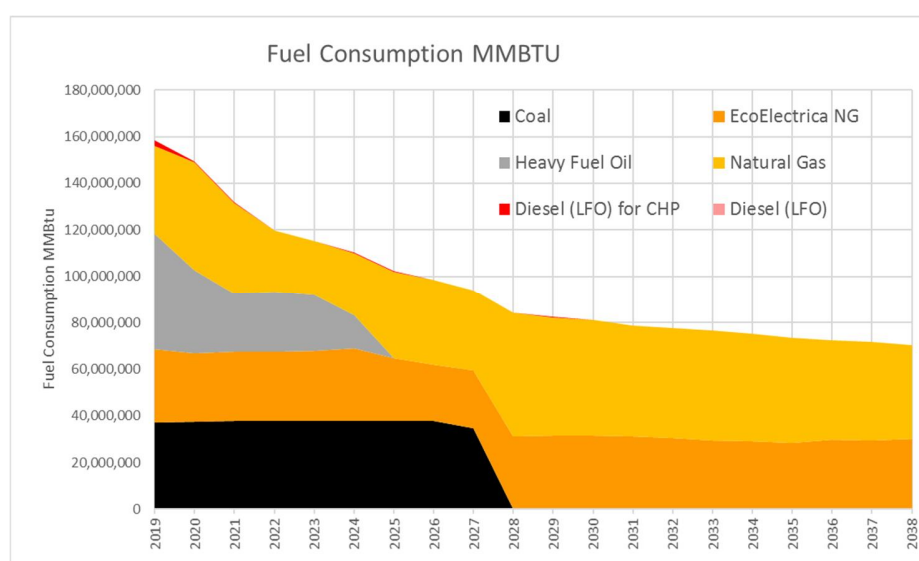


8.3.4 Fuel Diversity

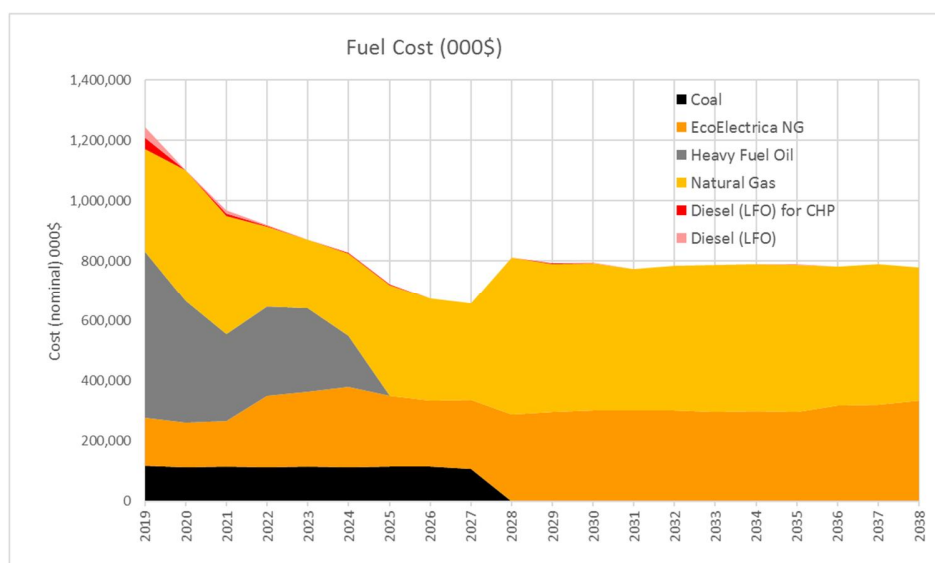
In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas. There is a significant decline in the overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines 44% by 2038 with the retirements of old Steam gas, heavy fuel oil and coal units. Under the high demand case, fuel consumption is 6% higher compared to the base load, driven by higher demand and Aguirre CCGT unit 2 staying online. Under the low demand case, fuel consumption is 10% lower driven by lower generation, peaking capacity and small CCGT in Ponce instead of a medium diesel CCGT in the base load.

However, fuel consumption is 95% higher compared to the least cost plan under Scenario 4.

Exhibit 8-40: ESM Plan Fuel Consumption



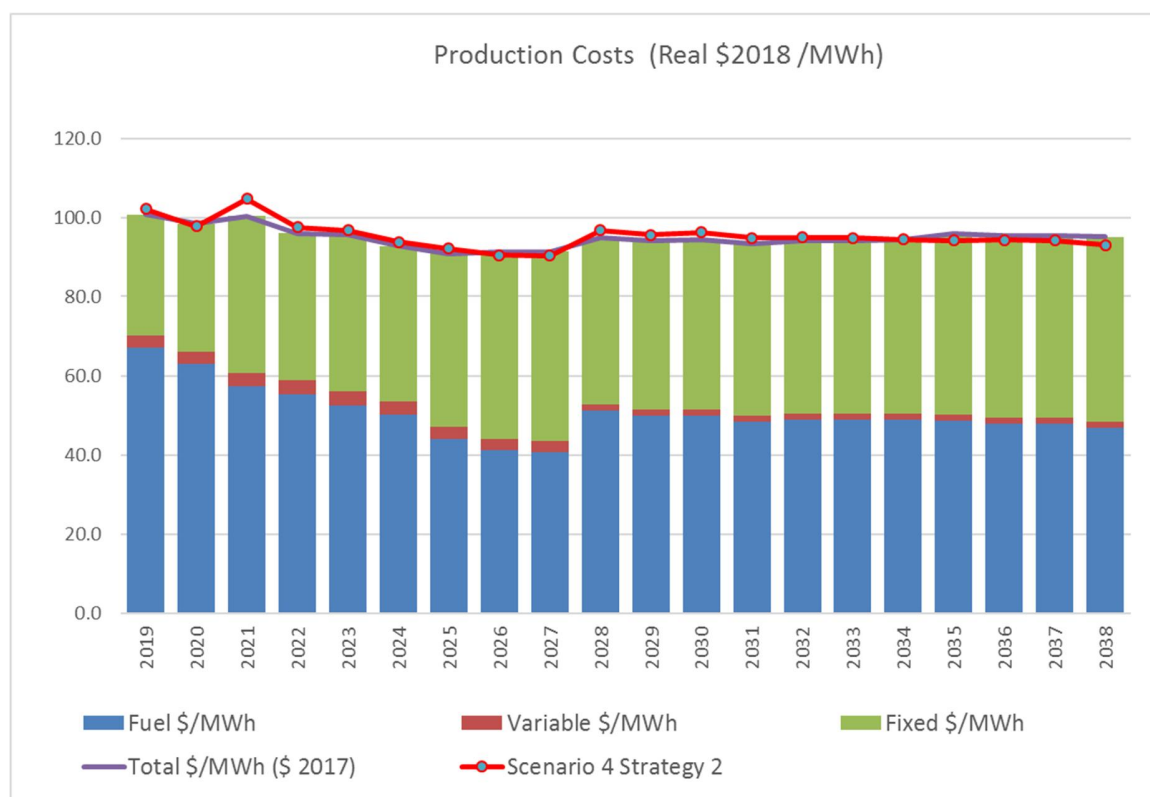
Fuel costs decline in line with the overall fall in fuel consumption falling to a low of \$659 million by 2027 (55% below 2019 levels) with all the retirements, including AES. Fuel costs increase in 2028 due to increase generation from EcoEléctrica and San Juan unit 5, after the retirement of AES. Fuel costs stay relative stable after 2028, on average at \$787 million in the last ten years of the planning period. Overall, fuel costs decline 36% by 2038. Under the high demand case, fuel costs are 8% higher compared to the base load case. In contrast, fuel costs are 11% lower under the low demand case.

Exhibit 8-41: ESM Plan Fuel Costs

8.3.5 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan and Base Load forecast from \$100.9/MWh in 2019 to \$91.0/MWh by 2025 (real \$2018), primarily due to the retirement of older generation and the addition of solar and storage. The overall costs increase in 2028 due to rising fuel costs with higher generation from EcoEléctrica and San Juan unit 5, after the retirement of AES (despite the offset from AES costs). Production costs average \$95.1/MWh for the first 10 years of the plan, 1.0% lower than the least cost plan under Scenario 4 portfolio (S4S2). In the last ten years of the plan, production costs average \$94.7/MWh, slightly lower than the least cost plan under Scenario 4.

The net present value of all operating costs reaches \$10.4 billion in 2019-2028 (nominal @ 9% rate). Over the planning period, the NPV is \$15.2 billion, only 0.06% lower than the least cost plan under Scenario 4 Portfolio.

Exhibit 8-42: Production Costs**Exhibit 8-43: System Costs ESM Plan, High and Low Load Cases**

Scenario	NPV @ 9% 2019-2038 \$Millions	Average 2019-2028 2018\$/MWh	NPV Deemed Energy Not Served MiniGrid Ops \$Millions	NPV + ENS \$Millions
ESM Plan Base Load	15,186	95.4	319	15,506
ESM Plan High Load	16,589	95.8	484	17,074
ESM Plan Low load	14,111	95.7	330	14,442

Under the high demand case, total system costs reach \$16.6 billion, \$1.4 billion above the plan under base load, mostly driven by higher capital investments (solar PV) and fuel costs. Under the low demand case, total system costs are \$1.1 billion below the plan under the base load driven by lower generation and capital investments. In other words, the upside risk in total costs is greater under the high demand case.

8.3.6 Resiliency (Mini Grid Considerations)

In the ESM plan, the critical loads are fully met with local generation by 2021, however the balance of the load is not fully covered while the plan is being developed in 2019 through 2022. After 2022, it varies depending on the MiniGrid region.

Siemens estimated the costs from unserved energy in the case of a major hurricane impacting the transmission system⁶¹. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a \$2000/MWh value for unserved energy, which considers that the load shedding will be rotated to minimize impact. The \$2000 is consistent with the cost of unserved energy for residential customers⁶².

Exhibit 8-20 summarizes the economic costs by MiniGrid region for the ESM plan. The largest potential costs are for Caguas and Carolina, followed by Arecibo and Cayey. Overall, there is an incremental 319 million in potential costs from unserved energy in the case of a major hurricane impacting the island under this plan. This compares to \$228 million for the least cost plan under Scenario 4 due to the fact that this plan has greater amounts of distributed solar resources. Considering the approximations made to determine these costs of Deemed Energy Not Served, the differences, however, are not considered material as the impact in the NPV of the Total Costs when the effect of the Deemed Energy Not Served is added, is about 82 million (0.6%).

Exhibit 8-44: Cost of Energy Not Served by MiniGrids

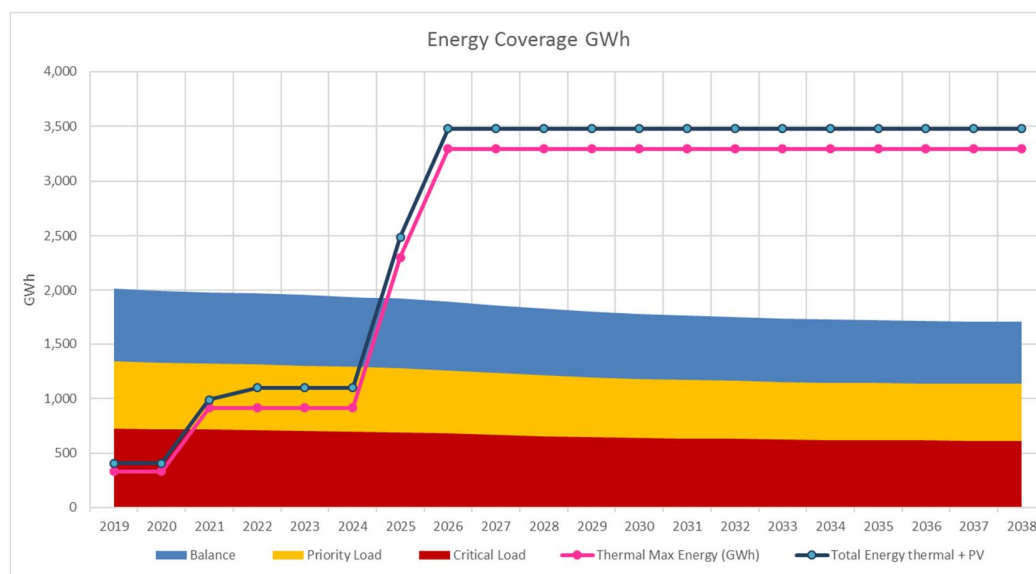
MiniGrid	ESM NPV Cost (\$000)	Scenario 4 NPV Cost (\$000)
San Juan-Bayamon	\$ 15,228	\$ 8,874
Ponce	\$ -	\$ -
Carolina	\$ 77,508	\$ 40,737
Caguas	\$ 103,020	\$ 127,850
Arecibo	\$ 63,825	\$ 25,110
Mayaguez-North	\$ 12,868	\$ 518
Mayaguez-South	\$ 12,837	\$ -
Cayey	\$ 34,004	\$ 25,196
Total	\$ 319,291	\$ 228,285

In Caguas, the total thermal energy available (inclusive of solar PV) covers the critical loads but not the priority loads through 2024 under the ESM case. The deployment of 115 MW of peakers (mobile) in 2021 seeks to cover the critical loads in this region under a MiniGrid operation (see Exhibit 8-45). The balance load is met in 2025 and onwards with the addition of a 302 MW F-Class CCGT in 2025 in Caguas. There is excess generation in this MiniGrid region afterwards.

⁶¹ This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of Scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served")

⁶² This value is much lower compared to the VOLL determined for PR, in the range of \$30,000/MWh

Exhibit 8-45: Caguas Energy Coverage under a Minigrid Operation

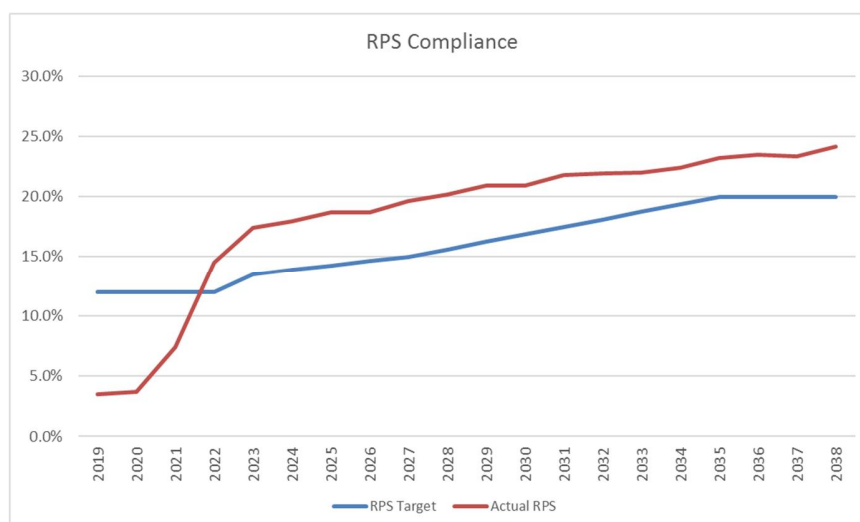


8.3.7 RPS and Environmental Compliance

8.3.7.1 Renewable Compliance

The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met in the ESM case. The plan achieved 24% renewable penetration by 2038, above the current regulation. Under the high demand case, the Plan reaches 40% renewable penetration due to the incremental solar PV with most of the incremental demand met with solar generation. Under the low load demand case, the Plan achieves 20% renewable penetration, somewhat lower than the base demand case.

The ESM plan may need to be revisited in the late 2020s if the proposed regulation of 50% renewable generation by 2040 is implemented. To assess the impact of this eventuality, Siemens ran a sensitivity analysis with a 50% renewable penetration by 2040, for which the results are provided in section 8.3.8.

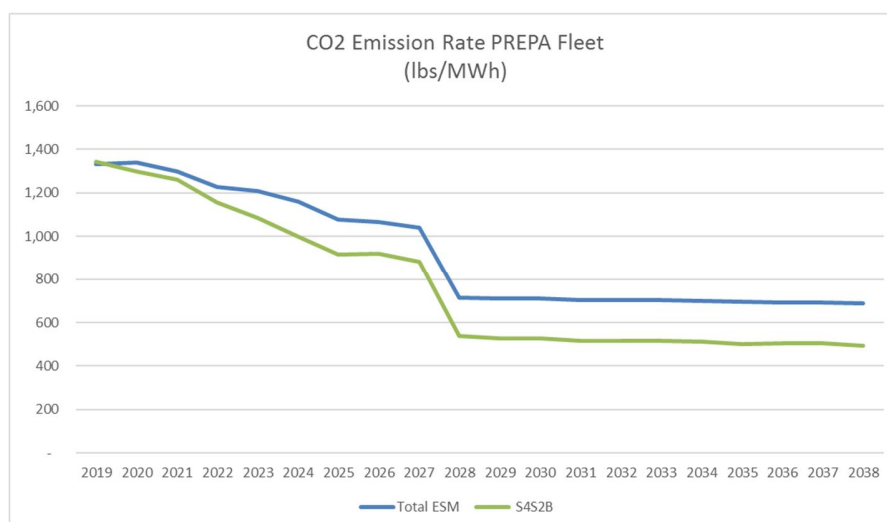
Exhibit 8-46: Renewable Portfolio Standards

8.3.7.2 Environmental Progress

CO₂ emissions for PREPA's fleet fall in the first ten years of the forecast driven by the retirement of the older fuel oil, diesel and gas units along with increased penetration of solar generation. Emissions fall 39% by 2027 and further by 60% a year later with AES coal retirement in 2028. Emissions continue falling but more gradually after 2028 reaching a 66% reduction by 2038. The emission rate for the fleet falls from 1,334 lbs./MWh in 2019 to 687 lbs./MWh in 2038. Total emissions under the ESM plan are 39% higher compared to the least cost plan under Scenario 4.

Under the high demand case, overall CO₂ emissions decline by 69% with more solar in the mix. Under the low demand case, emissions decline further 71% by 2038 due to overall lower demand and fossil generation.

The new CCGTs have the lowest emission rates at 820 lbs./MWh. San Juan units converted to natural gas also show low emissions rates at around 850 lbs./MWh. EcoEléctrica is also a low emitter at 877 lbs./MWh. The small 144 MW CCGT unit in the North has higher emissions rate at 918 lbs./MWh, which is shown in the total for CCGTs below prior to 2025 when the new CCGTs are in place. The unit with the highest CO₂ emission rates is AES coal at 2,155 lbs./MWh.

Exhibit 8-47: CO2 Emissions PREPA System**Exhibit 8-48: CO2 Emissions by Unit Type**

lb/MWh	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AES	2,155	2,155	2,154	2,154	2,154	2,154	2,154	2,154	2,154	-
EcoElectrica	877	877	876	878	878	878	878	879	879	877
Costa Sur 5&6	1,248	1,255	1,242	-	-	-	-	-	-	-
Existing Fleet (HFO)	1,430	1,526	1,704	1,699	1,716	1,687	-	-	-	-
Diesel CC (LFO)	159	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335
Existing GTs (LFO)	1771	1464	0	1813	0	0	0	0	0	0
SJ 5&6 With NG	866	863	852	852	850	851	849	850	846	849
New CCGT's	0	0	0	918	918	918	820	815	814	821
New Peaker gas	0	0	1211	1063	1038	1041	1065	1043	1047	1028
New Peaker diesel	0	0	0	0	0	0	0	0	0	0
Total ESM	1,334	1,340	1,300	1,229	1,207	1,161	1,076	1,066	1,039	713

8.3.8 ESM with 50% RPS Sensitivity

The Siemens team ran a sensitivity with a 50% renewable penetration by 2040 with the objective of evaluating the incremental costs and additional generation needed to meet the proposed long-term goal of 50% RPS by 2040. Under this sensitivity, PREPA would have to accelerate the renewable development in the late 2020s to reach 45% renewable penetration by 2038 and achieve the 2040 goal.

The plan has most of the additional solar PV added after 2031 with 840 MW additional PV added beyond that in the base ESM case. Solar PV additions do not change in 2020-2022 as they are also installed up to the predefined annual maximums. In 2023, there is 240 MW of incremental solar PV, compared to the base case. Battery storage additions are fairly aligned with the base case with 820 MW added during the study period.

System costs are only \$30 million higher (0.2%) under this plan (in present value) with most of the incremental capital investments happening after 2030. Overall production costs do not change significantly as the variable costs of operating solar is minimal. Thus, the ESM could be easily modified to achieve compliance with a 50% target by investing in additional solar PV starting in the late 2020s with minimal impacts on the economics.

Exhibit 8-49: EMS with 50% RPS Sensitivity System Costs

	50% Renewable	Base Case
NPV System Costs (\$000)	14,531	14,501
Average Production Costs \$/MWh (2019-2028)	95.4	95.3
RPS 2038	44%	23%

8.3.9 Rate Impact

In the sections above, we presented the composition of least cost portfolio formulated under the Energy System Modernization (ESM) Plan Base Case.

In this section, similar to the calculations for Scenario 4, we estimate the potential impact of the ESM portfolio on the final rates to customers; and compare the resulting final rates with the possible costs that the customers would incur for self-supply and other customer based alternatives.

The comparison is made considering the “Rate Components” presented earlier (see section 8.2.13.1)

8.3.9.1 Results of Comparison to Customer Based Alternatives

For rate comparison we considered, as before and are described in greater detail in Appendix 4, Demand Side Resources.

In this section we describe the results of the analysis we performed comparing the final ESM rates to unit costs for customer based alternatives.

The ESM generation portfolio costs are slightly lower compared to the S4S2 portfolio; however, the cost reduction is not significant enough to change the comparison observations and inferences for the S4S2 rate impact analysis. The comparison analysis results are illustrated in Exhibit 8-50, and are summarized below:

- The unit costs for all the customer alternatives considered are lower than the final all-in ESM generation portfolio rate.
- The levelized cost of customer alternatives (especially Solar PV and Grid Defection) is higher than the cost of the generation delivered to the customer and that includes the effect of losses until 2028 (when AES Coal retires). However, this cost is significantly lower than the total rate even before the non-bypassable component and confirms the assumption in the DG forecast that the continuance of ‘net-metering’ rates will occur, and the customer side roof top PV adoptions will continue to be in line with the high adoption rates observed to date.
- These results also indicate that, given PREPA’s forecasted non-bypassable rate component, coupled with the expected reduction in renewable generation costs, the customers may be motivated to self-supply if they are able to raise the capital investment required for installing the self-supply option or if a developer installs the equipment and recovers the investment through leases or other financing options.

- It is also interesting to note that when the Non-Bypassable charge is added to the case where the customer only has PV and uses PREPA as a bank (net-metering) the costs are very similar to the complete self-supply option. However, in this case there is an added advantage of no need for the initial capital outlay. So, provided that the PREPA service meets the reliability expectations of the customer, it can be reasonably concluded that the customer will continue to be connected to the PREPA grid.

We analyzed another case where we reduced the non-technical losses to typical values observed in the US (0.5% or less). Note that the distribution technical losses are within the expected values of PREPA's peers and account for the reduction in losses due to the increased penetration of distributed generation. Keeping all else the same, the resulting final rate for the ESM generation portfolio, also reduces, but not to the extent that our above observations and inferences change. This updated comparison chart is given in the exhibit below.

Exhibit 8-50: Final ESM Generation Portfolio Rates Compared to Unit Costs of Customer Alternatives

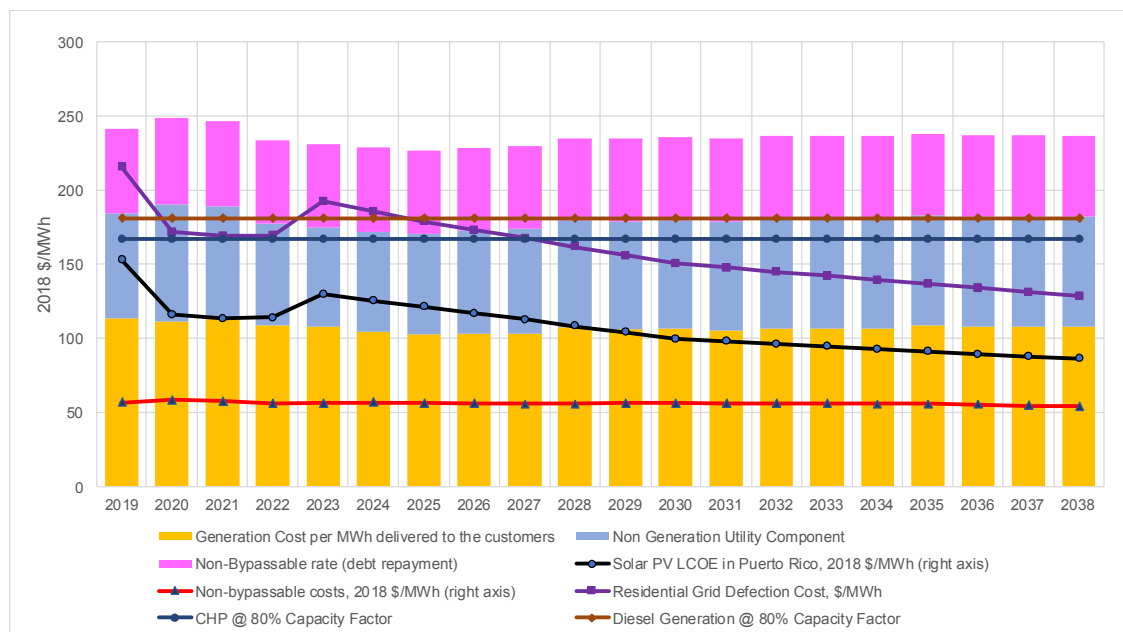
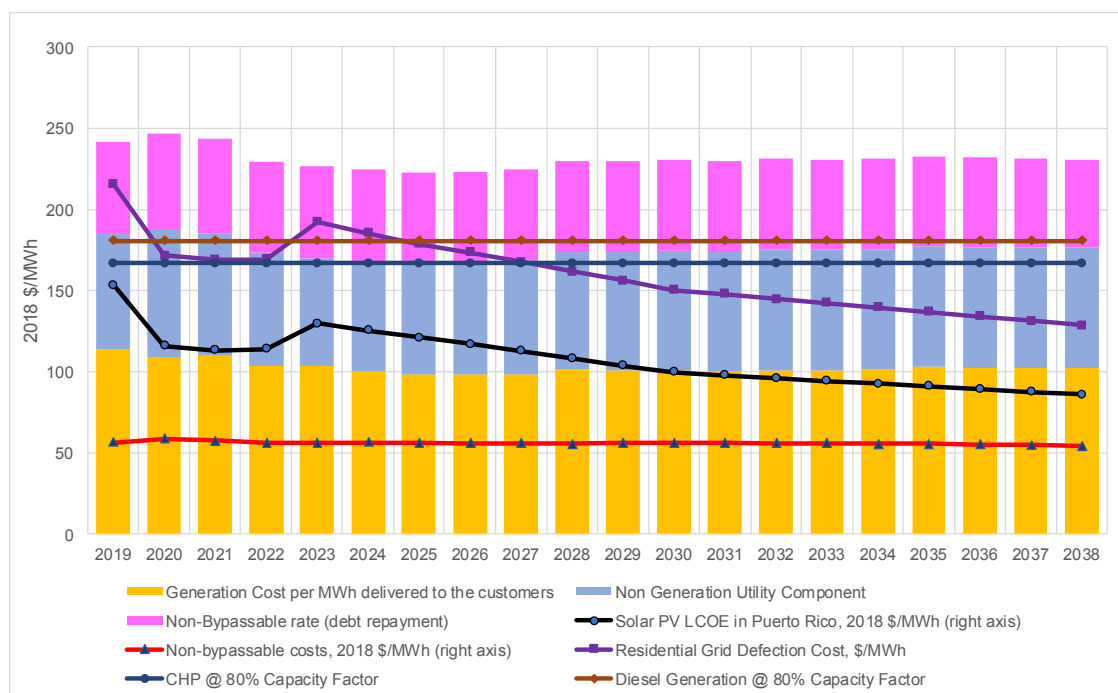


Exhibit 8-51: Final ESM Generation Portfolio Rates Assuming Reduced Losses



8.3.10 Nodal Analysis of the ESM

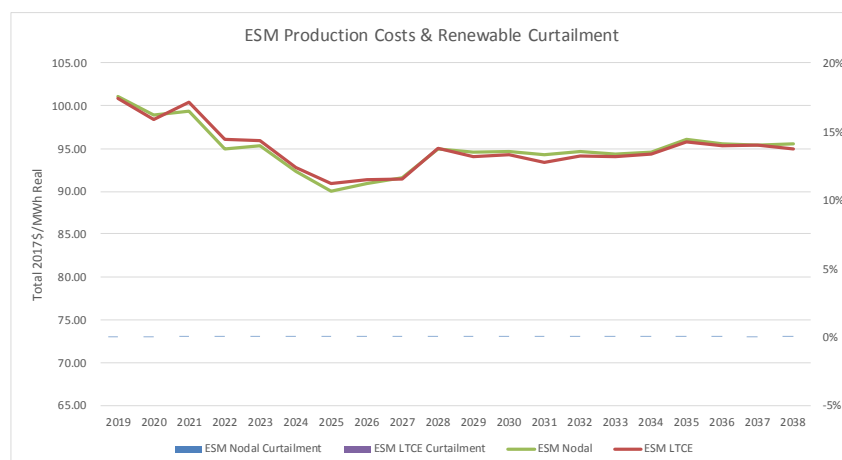
As was the case of Scenario 4, we analyzed the ESM using a nodal simulation. The objective again was to identify the effects of transmission on the key metrics of technical losses, production costs, renewable curtailment and energy not served.

The results of the nodal runs show the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment for the entire period and that there is no curtailment (see Exhibit 8-52).

The losses in each of the nodal cases was less than that of the zonal runs used, due to the more accurate modeling of the transmission system. On average the reduction in losses is approximately 1.0%. The difference in losses noted from 2019 – 2028 is an average of 1.5% lower. From 2029 – 2038 the losses difference is an average of 0.7% lower; see Exhibit 8-53.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

Exhibit 8-52: Production Costs Nodal vs. Zonal and Renewable Curtailment**Exhibit 8-53: Transmission Losses Differences**

Loss Difference	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
LTCE Losses	3.7%	3.2%	2.6%	2.6%	2.0%	2.1%	2.0%	2.0%	1.9%	1.1%	1.0%	1.0%	0.9%	0.9%	0.9%	0.9%	0.8%	0.8%	0.8%	0.7%
NODAL Losses	1.1%	1.0%	0.8%	0.7%	0.6%	0.5%	0.6%	0.6%	0.5%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
DIFFERENCE	2.6%	2.2%	1.8%	1.8%	1.4%	1.6%	1.4%	1.5%	1.4%	0.6%	0.5%	0.5%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.2%

8.4 Scenario 1 Results

Scenario 1 is a portfolio in which there is no new LNG terminals can be developed in the island. Only existing gas at the Cost Sur LNG terminal is available. The Scenario also considers base case assumptions for solar and storage costs and availability.

Scenario 1 was simulated under the base high and low load forecast and under three strategies, strategy 2 (decentralized 80% of demand met by local resources base case), strategy 3 (50% of demand met with local generation) and strategy 1 (centralized system).

Three sensitivities were run also with this Scenario; Sensitivity 1; low cost of renewable, Sensitivity 2 low levels of energy efficiency (1% reduction for 10 year) and Sensitivity 3 (Economic retirement of AES)

In general Scenario 1 result in a plan that has higher production costs compared to other plans including Scenario 4 and the ESM. Most of the increase in costs comes from a much larger development of solar and storage required to meet the load. Scenario 1 achieves much higher levels of renewable penetration in the order of 82% that requires intensive use of the storage and could be challenging to operate (3846 MW on a system that could have peak load little over 2,000 MW).

Resiliency at the MiniGrid level is comparable to the Scenario 4.

Exhibit 8-54 below provides a summary of the investments results for Scenario 1 and the key cost metrics in comparison with the S4S2B and the ESM case. Sensitivity 3 is being revised as of this writing as the AES plant was retired and this is inconsistent.

Exhibit 8-54. Scenario 1 Summary of results and comparison with Scenario 4 and ESM

Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	F-Class Mayaguez 2028	F-Class Yabucoa 2025	Small CCGT (LPG/NG) North	F - Class San Juan 2029	Medium CCGT Yabucoa 2024	Peakers (small CC) 2019-2022	New Solar 2019 - 2022	BESS 2019 - 2022	New Solar 2023 - 2028	BESS 2023 - 2028	New Solar Total	BESS Total
S1S2B	X	✓ (2025, 2028)	X	X	X	X	X	396	1200	1200	2520	380	3720	2140
S1S2H	X	✓ (2025 x 2, 2033)	X	X	X	X	✓ Palo Seco 2027	472	1200	1240	3060	120	4320	1880
S1S2L	X	✓ (2025, 2028)	X	X	X	X	X	303	1200	1160	2100	180	3300	1800
S1S3B	✓ (2025, 2028)	✓ (2025, 2028)	X	X	X	X	X	343	1200	1120	2520	160	3720	1640
S1S3H	✓ (141 MW)	✓ (2025, 2028)	X	X	X	X	✓ Palo Seco 2027	476	1200	940	3060	120	4260	2500
S1S3L	X	✓ (2025, 2028)	X	X	X	X	X	303	1200	1120	2040	20	3240	1900
S1S2S1B	✓ (141 MW)	✓ (2025, 2028)	X	X	X	X	X	345	1200	1120	2640	500	3840	2700
S1S2S2B	X	✓ (2025 x 2, 2028)	X	X	X	X	X	444	1200	1140	2820	80	4020	1800
S1S2S3B	✓ (S. Juan LFO)	✓ (2025)	X	X	X	X	✓ (LFO)	350	1200	1140	1140	0	2640	1560
S1S1B	X	✓ (2025, 2028)	X	X	X	X	X	297	1200	1160	2520	0	3720	2220
S4S2B-M	✓	✓	✓	X	X	X	X	387	1200	900	1020	40	2220	1080
S4S2H	✓	✓	✓	X	X	✓	✓	479	1200	800	1380	0	2580	960
S4S2L	✓	✓	X	X	X	X	X	280	1200	1100	900	60	2100	1160
ESM Plan	✓	Eco Instead	X	✓	✓	X	X	418	720	440	180	140	900	800
ESM high	✓	Eco Instead	X	✓	✓	X	X	477	720	440	960	160	1680	780
ESM low	✓	Eco Instead	X	✓	✓	X	X	418	720	440	0	140	720	640

Case ID	NPV @ 9% 2019-2038 \$000	Average 2019-2028 2018\$/MWh	RPS 2038
S1S2B	15,458,037	101.1	81%
S1S2H	17,177,891	101.7	89%
S1S2L	14,120,288	100	71%
S1S3B	15,401,758	101	76%
S1S3H	17,109,321	101	93%
S1S3L	14,052,124	99	71%
S1S2S1B	14,852,306	97	84%
S1S2S2B	16,640,966	100	84%
S1S2S3B	15,184,151	100	59%
S1S1B	15,395,763	101	81%
S4S2B-M	15,143,289	96.0	49%
S4S2H	16,995,234	99.0	57%
S4S2L	14,141,564	96.6	48%
ESM Plan	15,186,419	95.4	24%
ESM high	16,589,582	95.8	40%
ESM low	14,111,364	95.7	20%

8.4.1 Capacity Additions and Retirements for Scenario 1

The economic simulation of Scenario 1, Strategy 2 Base load (S1S2B) forecast 3,720 MW of utility scale PV additions over the study period with 1200 MW added in 2019-2022, maximizing solar PV capacity additions in the short to medium term, consistent with the least cost plans, e.g. Scenario 4, ESM and Scenario 3. All solar PV additions happen in the first 10 years of the plan. The high load case for Strategy 2 adds 600 MW of incremental solar to the base case results, or 4320 MW in total. The low load case for Strategy 2 adds 420 MW less than under the base load case or 3300 MW in total. Under strategy 3, solar additions are similar (see Exhibit 8-54).

To support the operation of large influx of solar, a total of 2,744 MW of battery energy storage is added over the study period, with about half of the total installed in 2019-2022. A second group of storage installations happen after the retirement of the AES in 2028. Storage additions are lower under the high load case (due to more CCGT additions) and the low load case (less need).

Two large CCGTs are installed, both in Costa Sur, one in 2025 and another in 2028, after the retirement of AES. These two plants utilize the gas available in the South after the retirement of the existing Costa Sur units, one retired in 2022 and the other in 2030. Under the high load case, an additional large CCGT is installed in Costa Sur in 2033 and a medium CCGT in Bayamon in 2027. Under the low load case, CCGT additions are the same as the base load case. There is not much difference either under Strategy 3, under

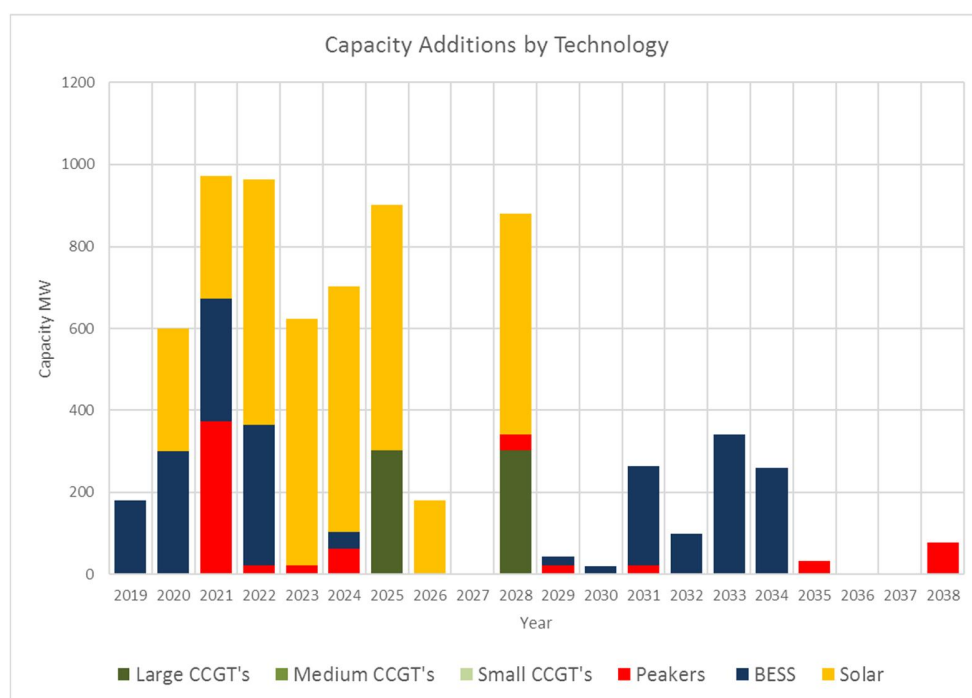
the high load case except for a small CCGT at Palo Seco in 2025 and a medium CCGT in Bayamon (see Exhibit 8-54).

The need for peaking capacity is somewhat larger compared to Scenario 4 over the planning period due to the higher renewable penetration, with an incremental 242 MW more of peakers (over the period 2019 -2022 values are similar). San Juan 5 & 6 are not converted to gas since in this Scenario assumes no new gas terminals are added to the island. San Juan 6 is retired in 2023 and San Juan 5, ten years later in 2033, under the base load case.

Under strategy 1 (a centralized plan), the expansion plan is very similar, both in terms of solar PV and storage additions, as well as CCGT capacity. Overall system costs are slightly lower but the risk and costs from unserved energy due to a disruptive hurricane are larger (see Exhibit 8-54).

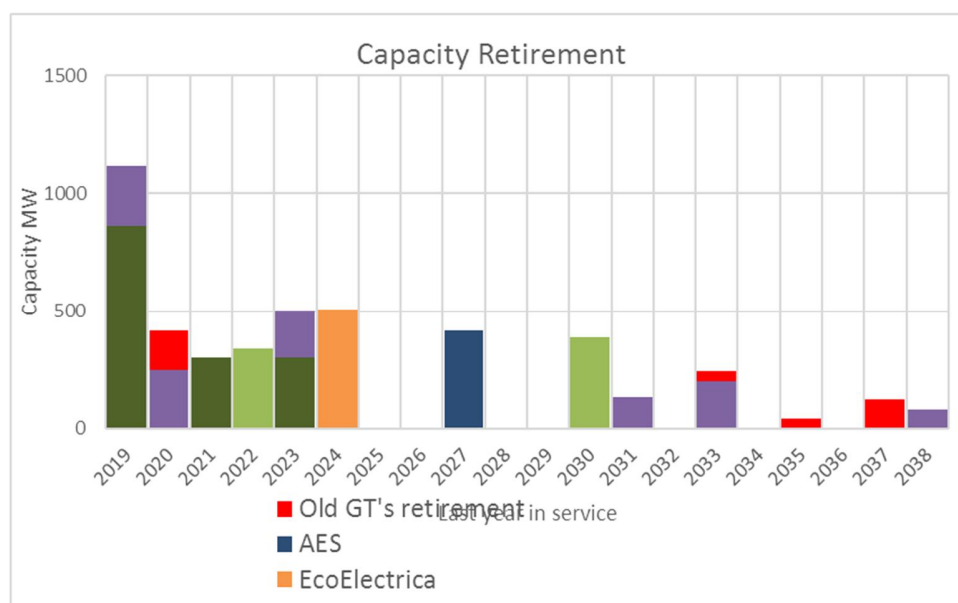
The plan is MATS compliant after 2024 and achieves 81% RPS compliance by 2038 (much higher than Scenario 4 or the ESM, with most of the new capacity coming from solar and storage).

Exhibit 8-55: Scenario 1 Base Load Capacity Additions



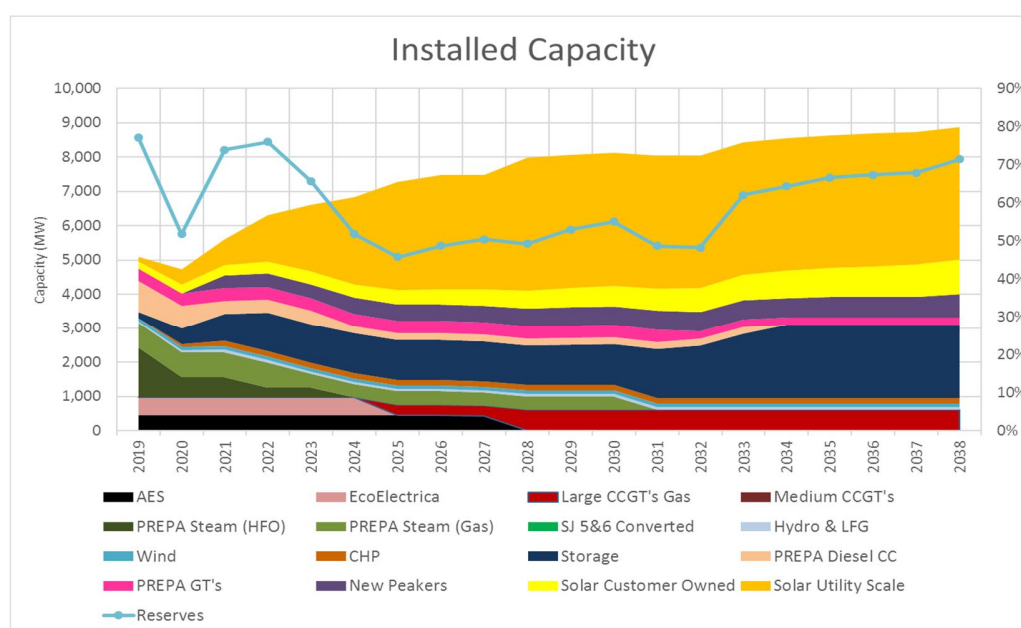
Capacity by technology MW		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Large CCGT's		0	0	0	0	0	0	302	0	0	302	0
Medium CCGT's		0	0	0	0	0	0	0	0	0	0	0
Small CCGT's		0	0	0	0	0	0	0	0	0	0	0
Peakers		0	0	373	23	23	62	0	0	0	39	23
BESS		180	300	300	340	0	40	0	0	0	0	20
Total Distchable Additions		180	300	673	363	23	102	302	0	0	341	43
Solar		0	300	300	600	600	600	600	180	0	540	0
Total Additions		180	600	973	963	623	702	902	180	0	881	43

Exhibit 8-56: Scenario 1 Base Load Capacity Retirements



Capacity by technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PREPA Steam (HFO)	862	0	300	0	301	0	0	0	0	0	0
PREPA MATS Affected units remaining						0	0	0	0	0	0
PREPA Costa Sur (Gas)	0	0	0	339	0	0	0	0	0	0	0
PREPA Diesel CC & large GTs	257	249	0	0	200	0	0	0	0	0	0
PREPA CC-converted (Gas)	0	0	0	0	0	0	0	0	0	0	0
EcoElectrica	0	0	0	0	0	507	0	0	0	0	0
AES									416	0	0
Total Dependable Gen Retirement	1119	249	300	339	501	507	0	0	416	0	0

Exhibit 8-57: Scenario 1, Future Capacity Mix



As PREPA's units and the thermal PPOA's are phased out, the operating reserves decline from 77% in 2019 to a low of 46% by 2025. The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this Scenario and observes a minimum of 41% in 2025.

8.4.1.1 Sensitivity Considerations

The Siemens team evaluated sensitivities under Scenario 1 to isolate the impacts of certain important variables while holding other assumptions constant. For the 2018 IRP, three sensitivities were modeled: low costs of solar and storage, low energy efficiency and economic retirements of AES.

Under low costs of renewables, there is a modest increase of 120 MW in solar additions and 560 MW from storage. This illustrates that even with lower costs of solar; an optimal amount of solar is installed under the base load case. In the case with low EE penetration, there is 300 MW of additional solar but 300 MW less storage.

8.4.2 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas and diesel along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. By 2038, 80% of the generation is coming from renewables.

Fuel consumption declines with the retirement of old gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Overall fuel consumption continues to fall through 2038 despite the new CCGTs install in Costa Sur in 2025-2028. Total fuel consumption drops to 20% by 2038 with most of the fuel used coming from natural gas.

Fuel costs decline in line with the overall fall in fuel consumption falling to a low of \$484 million by 2038 (60% below 2019 levels) with all the retirements, including AES. In this Scenario, 16% of the total fuel costs still come from diesel generation by 2038.

Exhibit 8-58: Scenario 1 Fuel Consumption

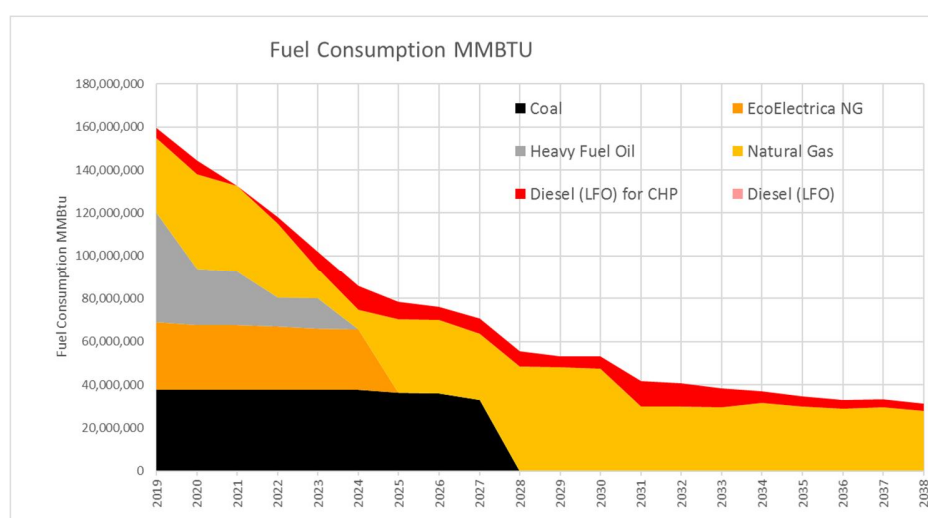
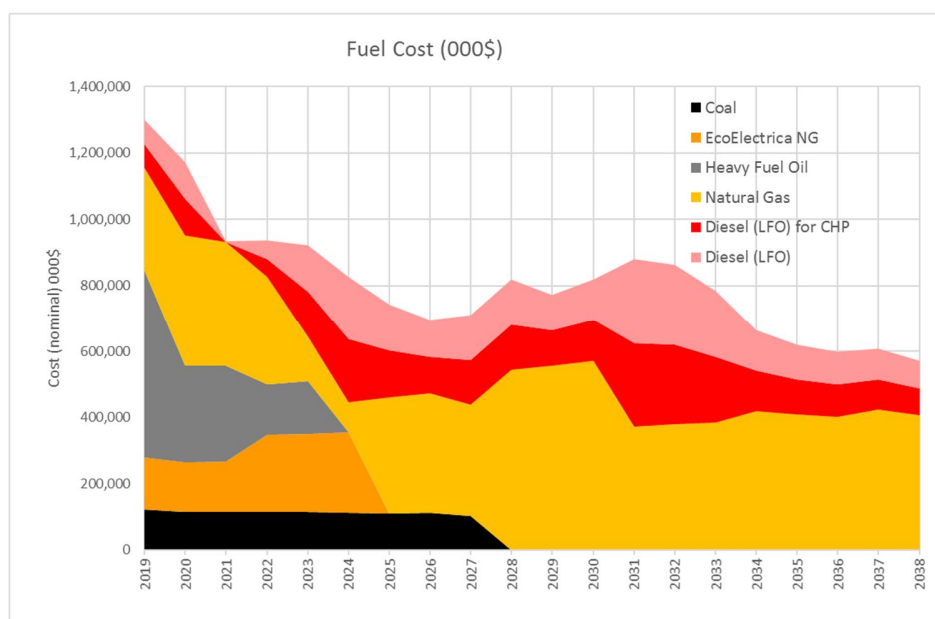
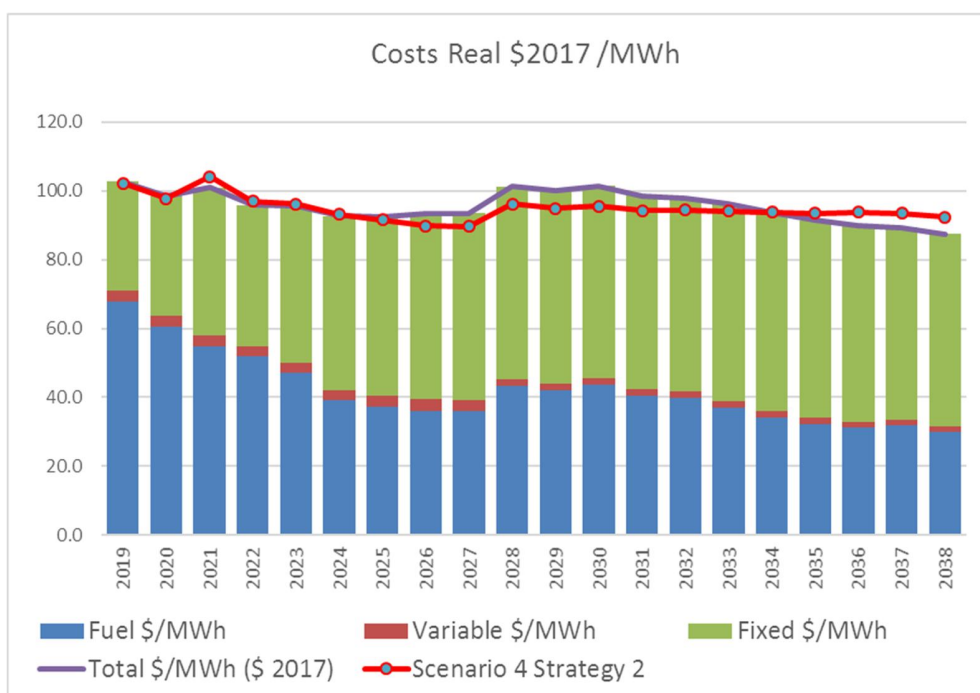


Exhibit 8-59: Scenario 1 Fuel Costs

8.4.3 System Costs

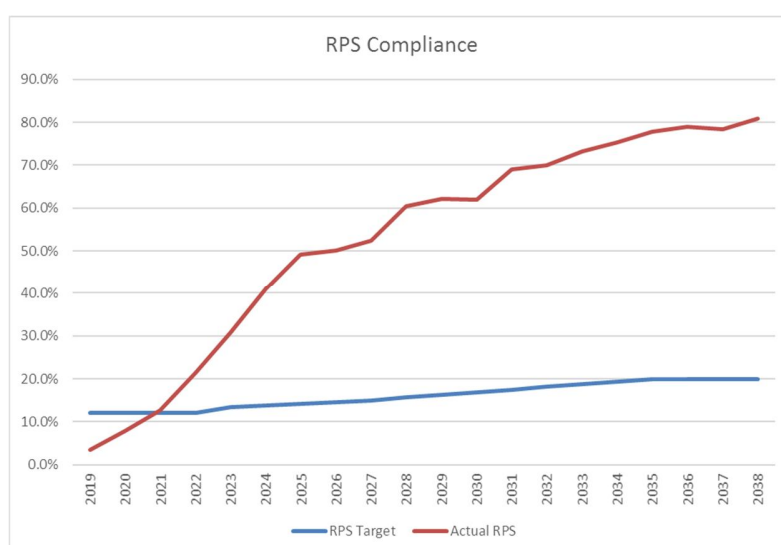
The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from \$ 103.4/MWh in 2019 to \$99.5/MWh by 2026 (real \$2018), prior to AES Coal retirement, with the addition of solar and storage and the retirement of older generation. The costs increased in 2028 to \$108.6/MWh with the addition of the new CCGT. The, system costs decline with falling fuel costs to reach \$100.0/MWh by 2038.

The net present value of all operating costs reaches \$10.9 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is \$15.4 billion. This plan is \$917 million more expansive compared to the reference Scenario 4, primarily due to higher capital investment costs with a lot more renewables and fuel costs with more diesel in the mix.

Exhibit 8-60: Scenario 1 Production Costs

8.4.4 RPS Compliance

The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met and exceeded in the Scenario 1 base case under all strategies. The plan achieved 81% renewable penetration by 2038, far exceeding the proposed regulatory goal of 50% renewable generation by 2040. This plan achieves much higher renewable contribution than Scenario 4.

Exhibit 8-61: Scenario 1 RPS Compliance

8.4.5 Rate Impact

In the sections above, we presented the composition of least cost portfolio formulated under the Scenario 1, Strategy 2 (S1S2) Base Case.

In this section and as was done before, we estimate the potential impact of the ESM portfolio on the final rates to customers; and compare the resulting final rates with the possible costs that the customers would incur for self-supply and other customer based alternatives.

The comparison is made considering the “Rate Components” presented earlier (see Scenario 4 Rate Impact)

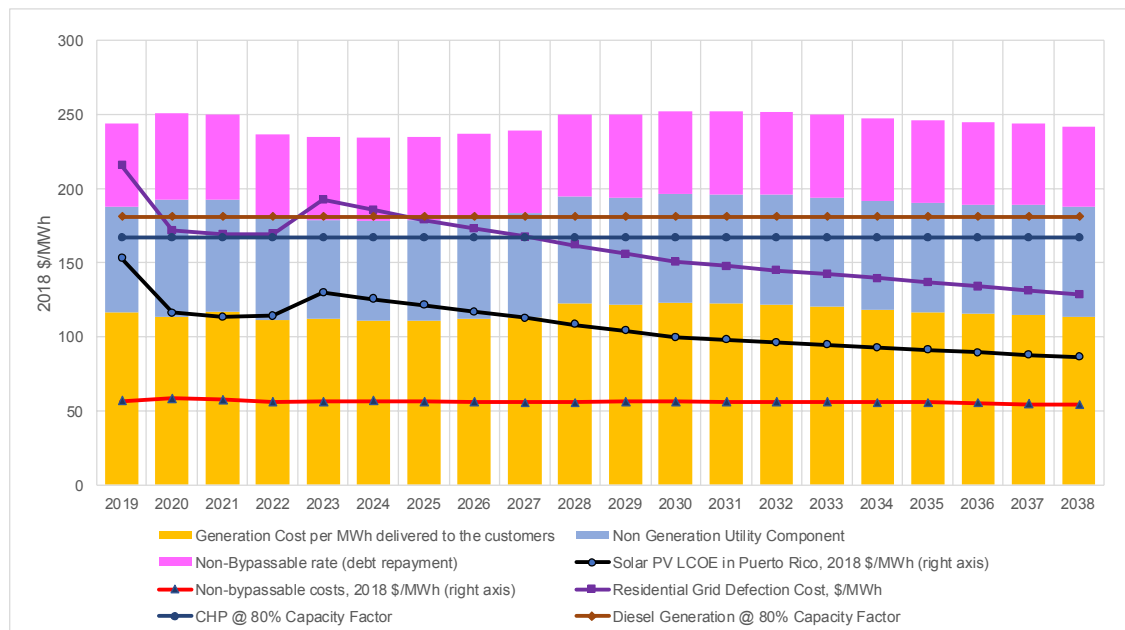
8.4.6 Results of Comparison to Customer Based Alternatives

In this section we describe the results of the analysis we performed comparing the final S1S2 rates to unit costs for customer based alternatives.

The S1S2 generation portfolio costs are higher than those of the S4S2 costs, but the comparison observations and inferences remain largely the same as those for the S4S2 rate impact analysis. The comparison analysis results are illustrated in Exhibit 8-62, and are summarized below:

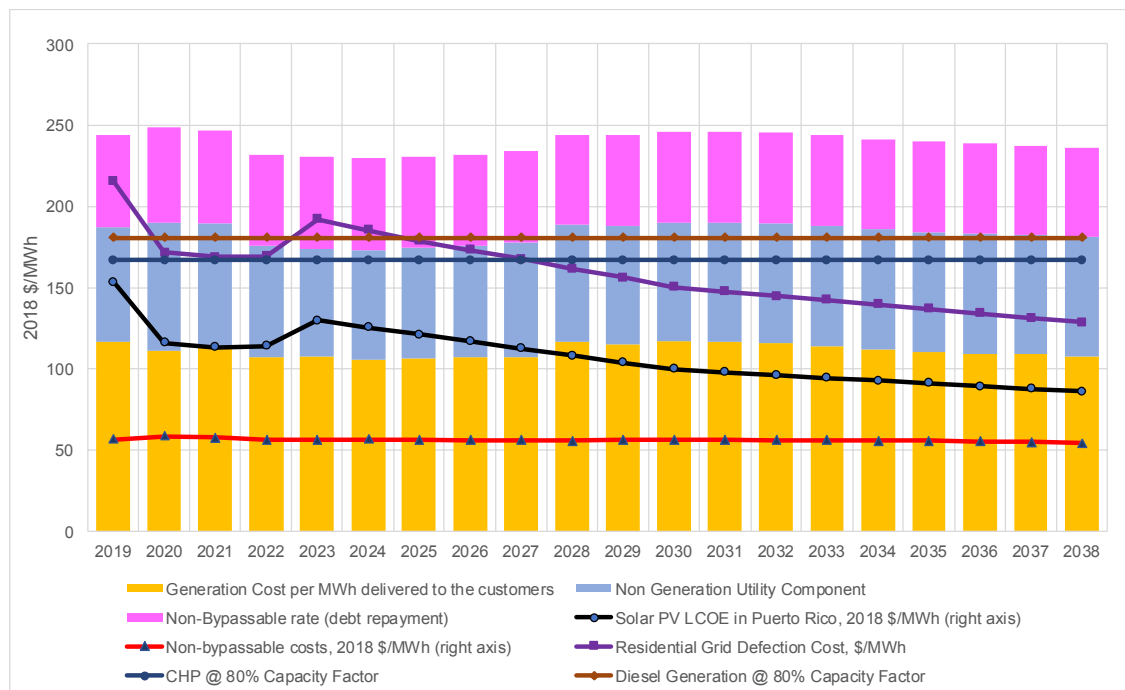
- The unit costs for all the customer alternatives considered are lower than the final all-in S1S2 generation portfolio rate.
- The levelized cost of customer alternatives (especially Solar PV and Grid Defection) is higher than the cost of the generation delivered to the customer and that includes the effect of losses until 2028 (when AES Coal retires). However, this cost is significantly lower than the total rate.
- These results also indicate that, given PREPA’s forecasted non-bypassable rate component, coupled with the expected reduction in renewable generation costs, the customers may be motivated to self-supply if they are able to raise the capital investment required for installing the self-supply option or if a developer installs the equipment and recovers the investment through leases or other financing options.

Exhibit 8-62: Final S1S2 Generation Portfolio Rates Compared to Unit Costs of Customer Alternatives



As before, we analyzed another case where we reduced the non-technical losses to typical values observed in the US (0.5% or less) and the resulting final rate for the S1S2 generation portfolio, also reduces, but not to the extent that our above observations and inferences change. This updated comparison chart is given in the exhibit below.

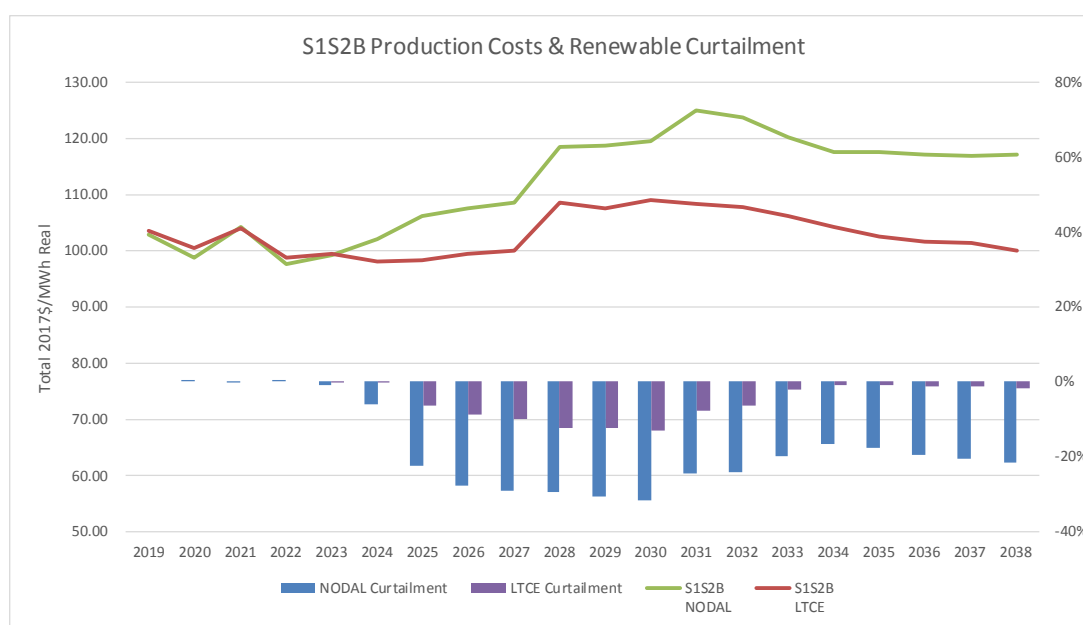
Exhibit 8-63: Final S1S2 Generation Portfolio Rates Assuming Reduced Losses



8.4.7 Nodal Analysis of the S1S2B

The nodal assessment highlighted the difficulty to manage the storage to integrate the large amounts of renewable in the case and potentially lead to large curtailment. The nodal runs used a different strategy to dispatch the storage that resulted in high levels of curtailment and increase in costs. We are not of the opinion that the results below are realistic and to be expected, but rather highlight this difficulty and risk. We are reviewing the dispatch logic and as a follow up of this report, we will provide an update. We expect that the curtailment will be in line with the long term capacity expansion plan and/or more storage will be required for the integration. The technical loss reduction was also noted with values similar as before.

Exhibit 8-64: Production Costs Nodal vs. Zonal and Renewable Curtailment



8.5 Scenario 3 Base Case Results

8.5.1 Capacity Additions and Retirements

The generation portfolio identified as Scenario 3 Strategy 2 (S3S2) result in a plan that has lower production costs as compared to the Scenario 4 and the ESM. The portfolio has a good balance of resources for a distributed system on a minigrid level capable of supplying the critical and priority loads for the customer in an event of a major disruptive hurricane.

However, the implementation of 4,020 MW of solar in a system with a 2,200 MW peak demand would be a significant challenge and could be difficult to achieve for practical reasons. The operation of the system would be a challenge with such a high level of solar penetration and its natural variability, increasing the risk of curtailment (that would negate some of the perceived economies) and putting strain and reliance on the energy storage.

The Scenario assumes lower capital investment costs for solar and storage (NREL Low Case) coupled with high availability of renewables (early ramp up). It also assumes gas available at Yabucoa (east) and Mayagüez (west) through ship-based LNG, in addition to gas

to the north supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approvals.

The economic simulation of the Scenario 3 case results in 4,020 MW of utility scale PV additions over the study period with 1,500 MW added as soon as 2022 (the maximum available, consistent with the PREB orders). Solar installations are 1,800 MW larger compared to Scenario 4. The amount of solar capacity additions varies depending on the load forecast with 4,560 MW under a high load case and 3,480 MW under a low load case. If the Scenario is simulated under Strategy 3, there is a slight reduction in solar builds with 3,960 MW under a base load case due to lower capacity requirements at the MiniGrid level (see Exhibit: 8-65).

In strategy 2 2,380 MW of battery energy storage is built over the study period, mostly in 2019-2023 hitting the annual installation limits allowed for most years (2019 to 2022). A second batch of storage is installed after AES and San Juan 5 retirement.

Only two large CCGTs are installed with 302 MW each in Costa Sur and Palo Seco (Bayamon), under the base load case. Under the low load case, the Palo Seco CCGT is added by 2027. In the high load case, there is no change under strategy 2 but the Palo Seco CCGT unit is delayed for strategy 3 until 2027.

Due to the higher renewable penetration, there is a larger need for peaking capacity to balance the system with 517 MW, 135 MW more compared to Scenario 4. San Juan units 5 & 6 converted to natural gas in 2019, with San Juan 5 retired economically in 2034 and San Juan 6 in 2032. EcoEléctrica is retired in 2024, in line with Scenario 4.

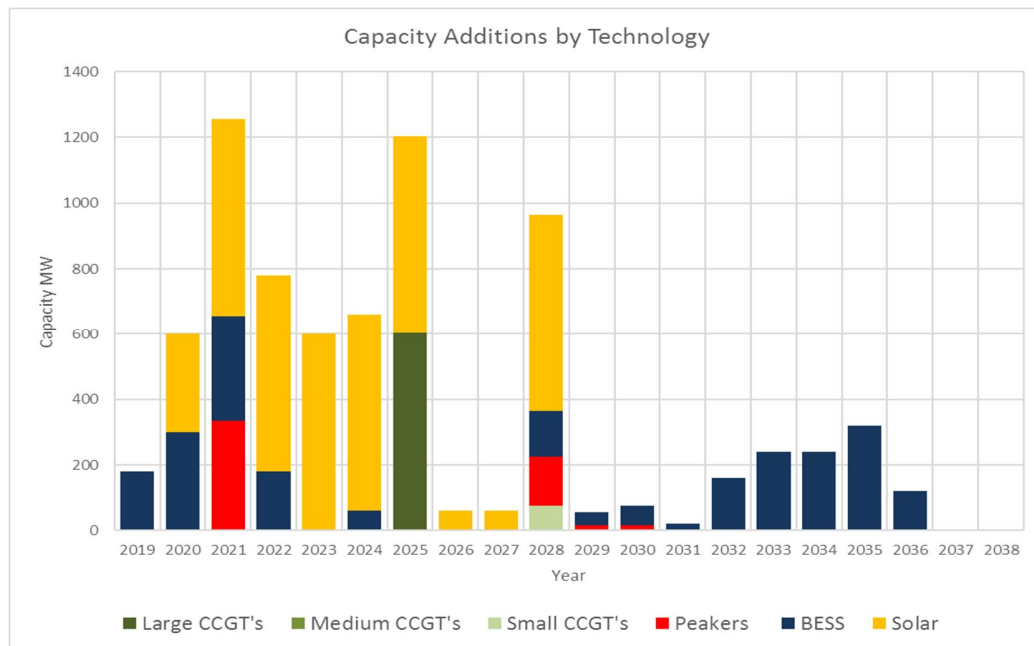
The plan is MATS compliant after 2024 and achieves 87% RPS compliance by 2038 (much higher than the Scenario 4 portfolio) as a result of lower costs of renewables and higher availability.

Exhibit: 8-65: Scenario 3 Results and comparison with Scenario 4 and the ESM

Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	F-Class Mayaguez 2028	F-Class Yabucoa 2025	Small CCGT (LPG/NG) North	F - Class San Juan 2029	Medium CCGT Yabucoa 2024	Peakers (small CC) 2019-2022	New Solar 2019 - 2022	BESS 2019 - 2022	New Solar 2023 - 2028	BESS 2023 - 2028	New Solar Total	BESS Total
S3S2B	✓	✓	X	X	X	X	X	303	1500	980	2520	200	4020	2380
S3S2H	✓	✓	X	X	X	X	X	303	1500	1180	4560	200	4560	3260
S3S2L	✓ 2027	✓	X	X	X	X	X	303	1500	940	1980	240	3480	1980
S3S3B	✓	✓	X	X	X	X	X	303	1500	1020	2460	260	3960	3960
S3S3H	✓ 2027	✓	X	X	✓ (76MW)	X	✓	303	1500	1100	2880	100	4560	2220
S3S3L	✓ 2027	✓	X	X	X	X	X	303	1500	960	1860	260	3420	2440
S4S2B	✓	✓	✓	X	X	X	X	372	1200	900	1020	40	2220	1080
S4S2B-M	✓	✓	✓	X	X	X	X	387	1200	900	1020	40	2220	1080
S4S2H	✓	✓	✓	X	X	✓	✓	479	1200	800	1380	0	2580	960
S4S2L	✓	✓	✓	X	X	X	X	280	1200	1100	900	60	2100	1160
ESM Plan	✓	Eco Instead	X	✓	✓	X	X	418	720	440	180	140	900	800
ESM high	✓	Eco Instead	X	✓	✓	X	X	477	720	440	960	160	1680	780
ESM low	✓	Eco Instead	X	✓	✓	X	X	418	720	440	0	140	720	640

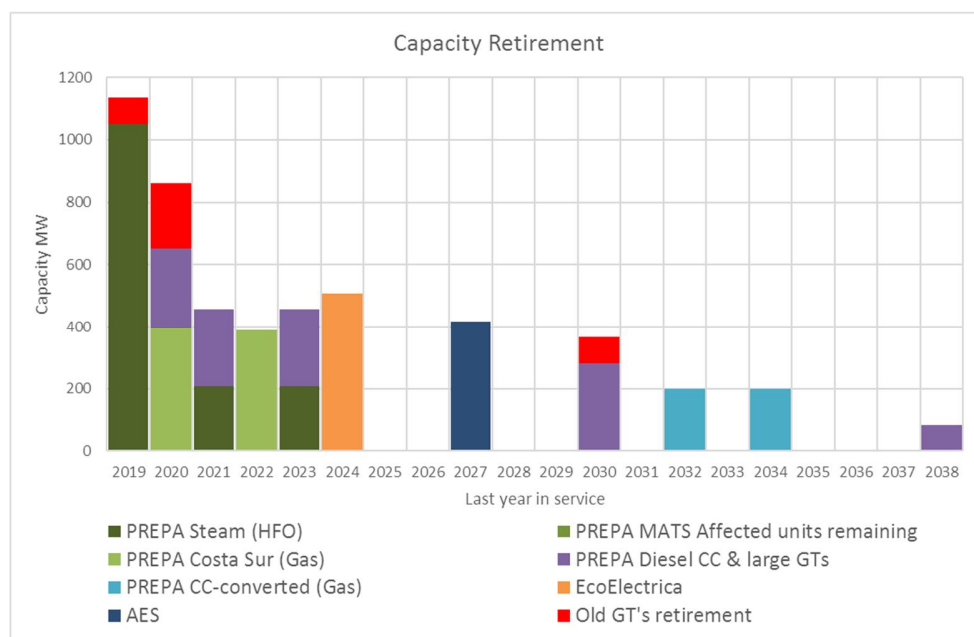
Case ID	NPV @ 9% 2019 2038 \$000	Average 2019-2028 2018\$/MWh	RPS 2038
S3S2B	14,167,571	93	87%
S3S2H	15,414,838	94	99%
S3S2L	12,910,613	92.3	76%
S3S3B	14,074,355	93.3	87%
S3S3H	15,394,694	93.4	96%
S3S3L	12,876,825	91.8	96%
S4S2B	15,195,166	96.3	49%
S4S2B-M	15,143,289	96.0	49%
S4S2H	16,995,234	99.0	57%
S4S2L	14,141,564	96.6	48%
ESM Plan	15,186,419	95.4	24%
ESM high	16,589,582	95.8	40%
ESM low	14,111,364	95.7	20%

Exhibit 8-66: Scenario 3 Base Load Forecast Capacity Additions



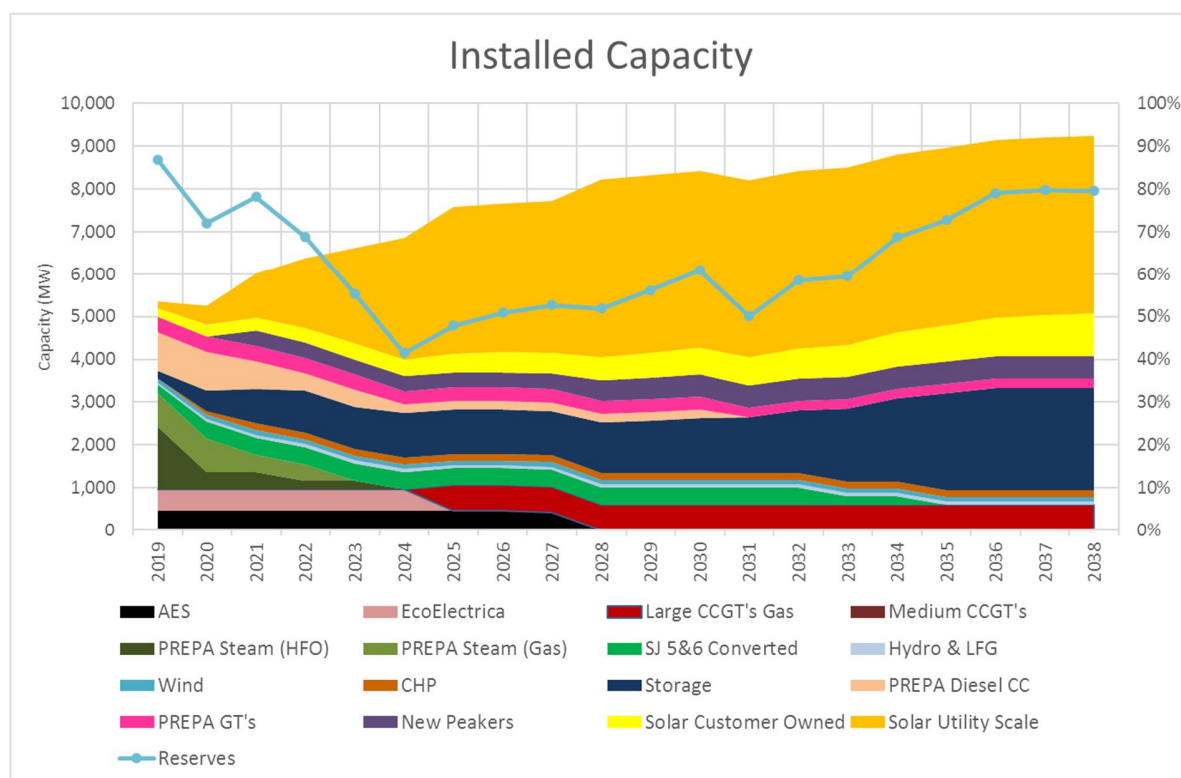
Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Large CCGT's	0	0	0	0	0	0	604	0	0	0	0
Medium CCGT's	0	0	0	0	0	0	0	0	0	0	0
Small CCGT's	0	0	0	0	0	0	0	0	0	76	0
Peakers	0	0	335	0	0	0	0	0	0	149	16
BESS	180	300	320	180	0	60	0	0	0	140	40
Total Distachable Additions	180	300	655	180	0	60	604	0	0	365	56
Solar	0	300	600	600	600	600	600	60	60	600	0
Total Additions	180	600	1,255	780	600	660	1,204	60	60	965	56

Exhibit 8-67: Scenario 3 Base Load Forecast Capacity Retirements



Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PREPA Steam (HFO)	1050	0	206	0	206	0	0	0	0	0	0
PREPA MATS Affected units remaining						0	0	0	0	0	0
PREPA Costa Sur (Gas)	0	393	0	388	0	0	0	0	0	0	0
PREPA Diesel CC & large GTs	0	257	249	0	250	0	0	0	0	0	0
PREPA CC-converted (Gas)	0	0	0	0	0	0	0	0	0	0	0
EcoEléctrica	0	0	0	0	0	507	0	0	0	0	0
AES									416	0	0
Total Dependable Gen Retirement	1050	650	455	388	456	507	0	0	416	0	0

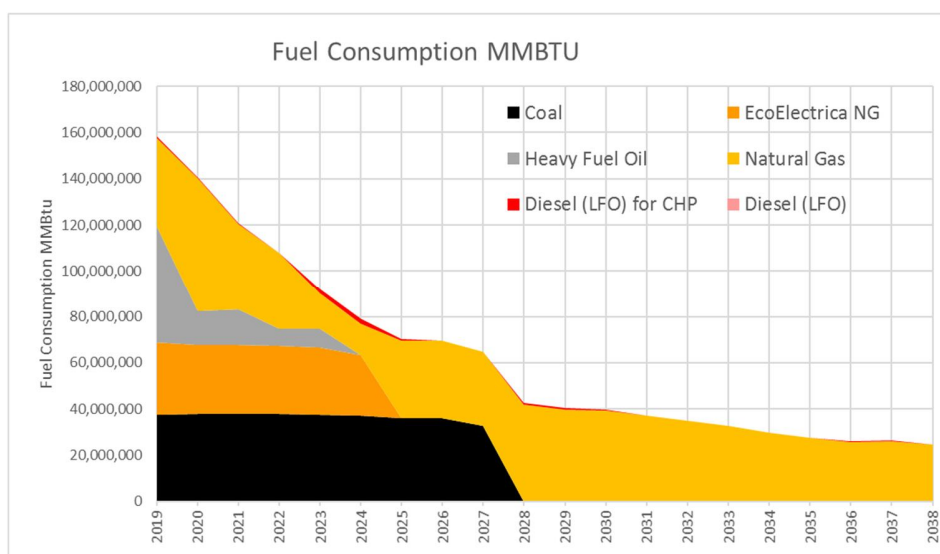
As PREPA's units and the thermal PPOA's are phased out the operating reserves decline from 87% in 2019 to a low of 41% by 2024, after EcoEléctrica's retirement. The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this Scenario and observes a minimum of 38% in 2024.

Exhibit 8-68: Scenario 3 Future Capacity Mix

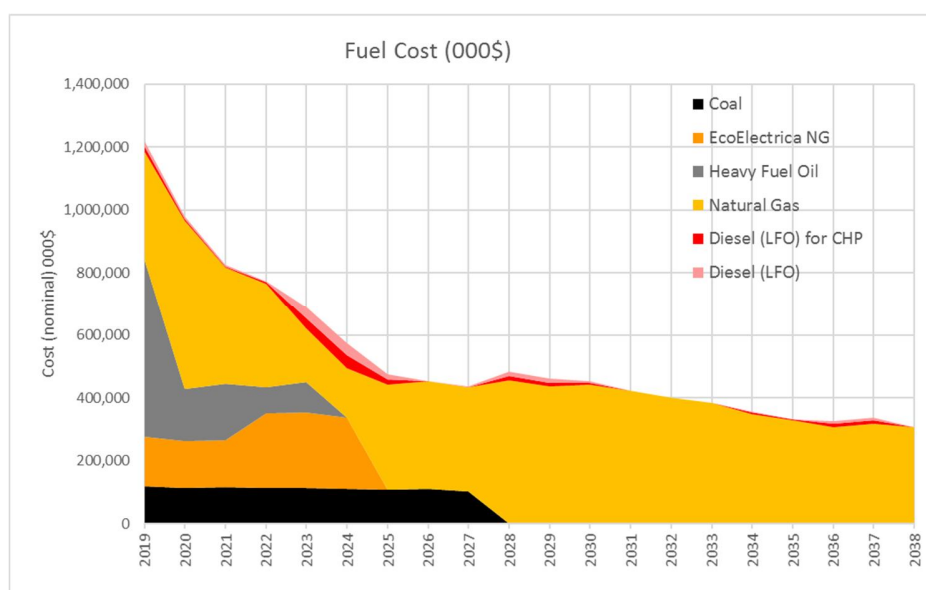
8.5.2 Fuel diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. By 2038, 82% of the generation is coming from renewables.

Fuel consumption declines with the retirements of old gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Overall fuel consumption continues to fall through 2038 despite the new CCGTs in Palo Seco and Costa Sur in 2025. Total fuel consumption drops 85% by 2038 with most of the fuel used coming from natural gas.

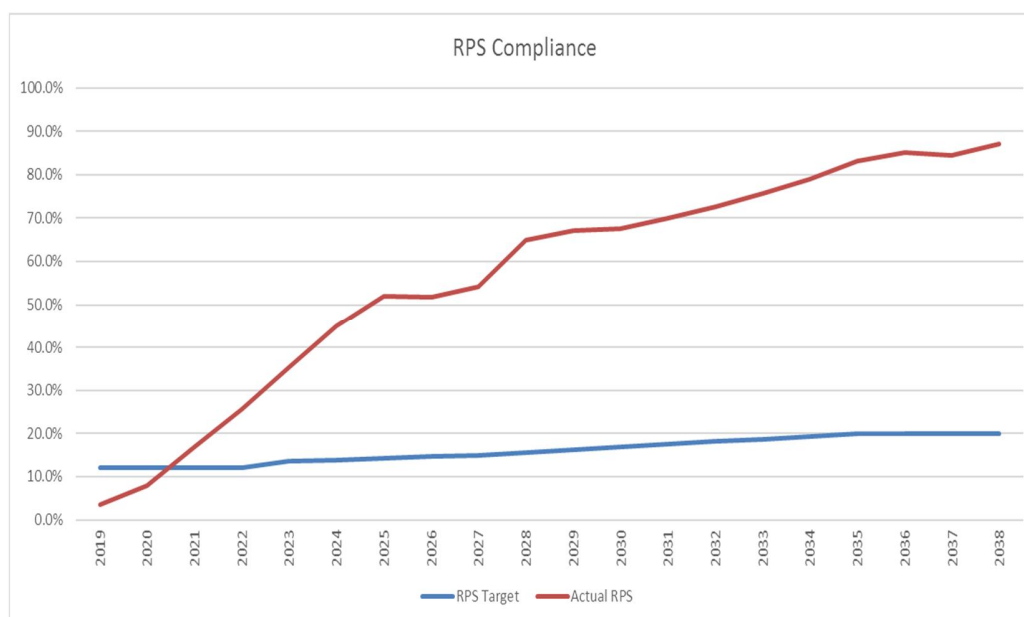
Exhibit 8-69: Scenario 3 Fuel Consumption

Fuel costs decline in line with the overall fall in fuel consumption falling to a low of \$307 million by 2038 (74% below 2019 levels) with all the retirements, including AES.

Exhibit 8-70: Scenario 3 Fuel Consumption

8.5.3 RPS Compliance

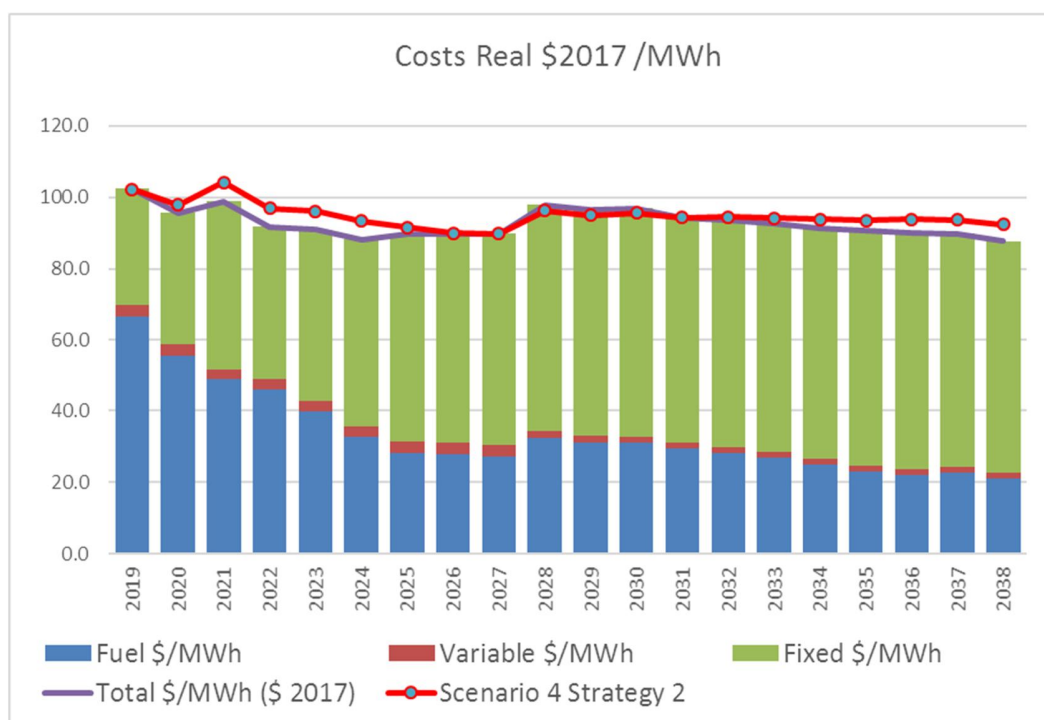
The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met and exceeded in the Scenario 3 base case under all strategies. The plan achieved 87% renewable penetration by 2038, far exceeding the proposed regulatory goal of 50% renewable generation by 2040.

Exhibit 8-71: RPS Compliance Scenario 3

8.5.4 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from \$ 102.5/MWh in 2019 to \$89.8/MWh by 2027 (real \$2018), prior to AES Coal retirement. The costs increased in 2028 with the addition of 600 MW of new solar and 126 MW of peakers to fall again in the 2030s due to falling fuel costs to reach \$87.7/MWh by 2038.

The net present value of all operating costs reaches \$10.1 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is \$14.1 billion. This plan is 2.5% lower in costs over the study horizon.

Exhibit 8-72: Scenario 3 Production Costs

8.5.5 Resiliency (Mini Grid Considerations)

In Scenario 3 plan, the critical loads are met by 2021. After 2022, both critical and priority loads are met for most MiniGrid regions.

Siemens estimated the potential costs from unserved energy in the case of a major hurricane impacting the transmission system⁶³. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a \$2000/MWh cost from unserved energy, which considers that the load shedding will be rotated to minimize impact. The \$2000 is consistent with the cost of unserved energy for residential customers⁶⁴.

Exhibit 8-20 summarizes the economic costs by MiniGrid region for Scenario 3. There are potential costs for San Juan-Bayamon and Caguas and to a lesser extent in Mayagüez North. Overall, there is an incremental 80 million in potential costs from unserved energy in the case of a major hurricane impacting the island under this plan. This is much lower compared to \$228 million for Scenario 4.

⁶³ This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of Scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served")

⁶⁴ This value is much lower compared to the VOLL determined for PR, in the range of \$30,000/MWh

Exhibit 8-73: Cost of Energy Not Served by MiniGrids

MiniGrid	NPV Cost (\$000)	Strategy 2
San Juan-Bayamon	\$ 32,101	\$ 8,874
Ponce	\$ -	\$ -
Carolina	\$ -	\$ 40,737
Caguas	\$ 46,423	\$ 127,850
Arecibo	\$ -	\$ 25,110
Mayaguez-North	\$ 1,573	\$ 518
Mayaguez-South	\$ -	\$ -
Cayey	\$ -	\$ 25,196
Total	\$ 80,098	\$ 228,285

8.6 Scenario 5 Base Case Results

Scenario 5 is a case requested by the Energy Bureau to evaluate how the capacity expansion would look with minimal restrictions. For this Scenario, in addition to the LNG terminal considered in Scenario 4, the Aguirre Offshore Gas Port (AOGP) is assumed to achieve full permitting and regulatory approval and can move forward. In line with the minimal restriction approach, the Scenario reflects a traditional and centralized energy program that emphasizes economic and reliability on a system integrated basis (Strategy 1) without minimum generation requirements to meet peak demand on a regional basis.

Other assumptions in the simulation of this Scenario includes gas to Yabucoa (east) and Mayagüez (west) through ship-based LNG, as well as gas to the north through land-based LNG at San Juan. The Scenario uses the base case assumption of solar and storage costs and availability. In addition, a larger combined cycle (H-class) could be built in this Scenario.

The generation portfolio identified as Scenario 5 Strategy 1 result in a plan that has lower production costs as compared to Scenario 4, about \$426 million below. However, the potential costs reductions could be fully offset if the transmission network is impacted by a major hurricane placing the system into MiniGrid operations (the system is segmented in areas). A high-level estimate of the impact shows \$1.1 billion of potential costs from energy not served during a month while the transmission system is repaired.

8.6.1 Capacity Additions and Retirements

The economic simulation of the Scenario 5 results in 2,160 MW of utility scale PV additions over the study period, only 60 MW below Scenario 4 plan. There is 1,200 MW in 2019-2022, hitting allowed yearly limits, in line with Scenario 4.

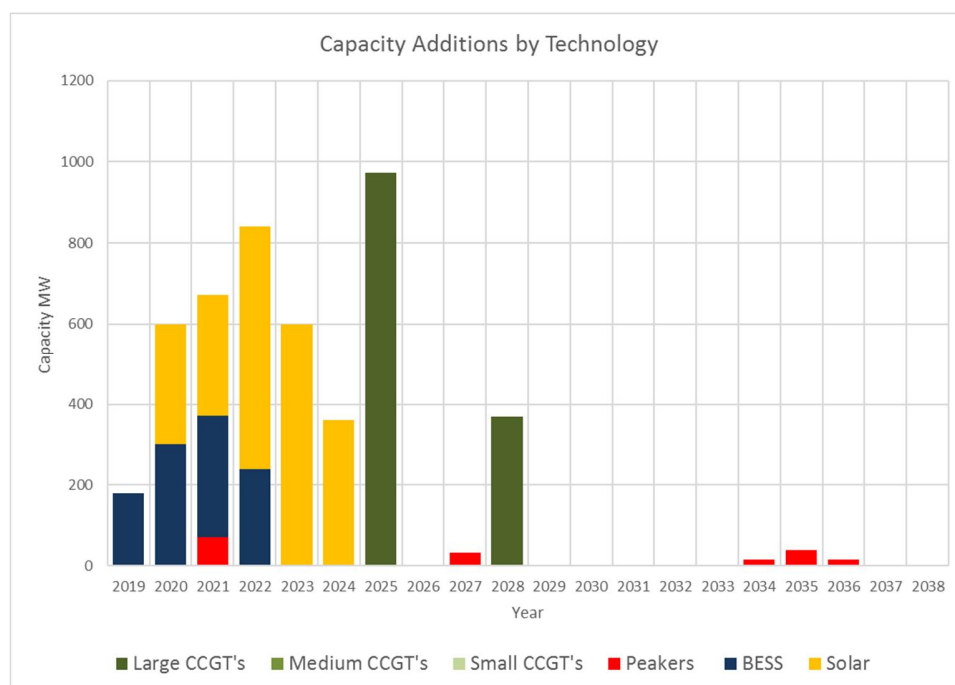
In this Scenario, 1,020 MW of battery energy storage is built over the study period, mostly in 2019-2022, reaching the annual installation limits in that period, in line with the plan for Scenario 4.

Four large F-Class CCGTs are installed, two in Palo Seco (Bayamon) and two in Costa Sur (Ponce west). Due to the addition of large combined cycles, the peaking need in this case is lower than Scenario 4 portfolio with 174 MW.

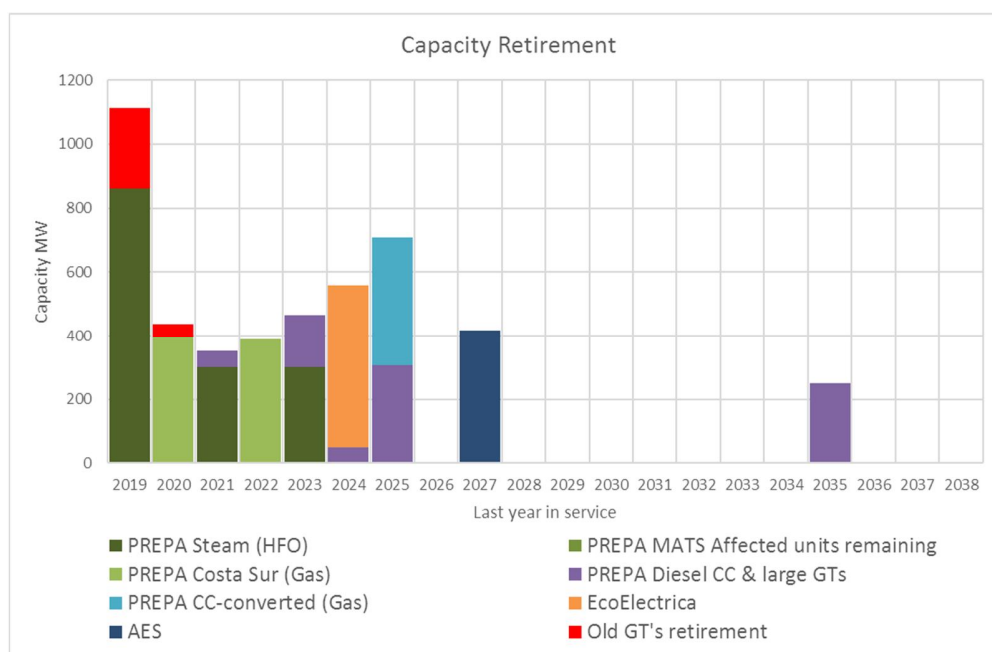
San Juan 5 and 6 are retired both economically in 2025 after being converted to natural gas in 2019. EcoEléctrica is retired economically in 2024, in line with most Scenarios (except for the ESM case that considered further reductions on the capacity payments) and AES retires by the end of 2027, by model input.

The plan is MATS compliant after 2024 and achieve 49% RPS compliance by 2038 (lower than the Scenario 4 portfolio), but in line to achieve 50% penetration by 2040.

Exhibit 8-74: Scenario 5 Portfolio Capacity Additions



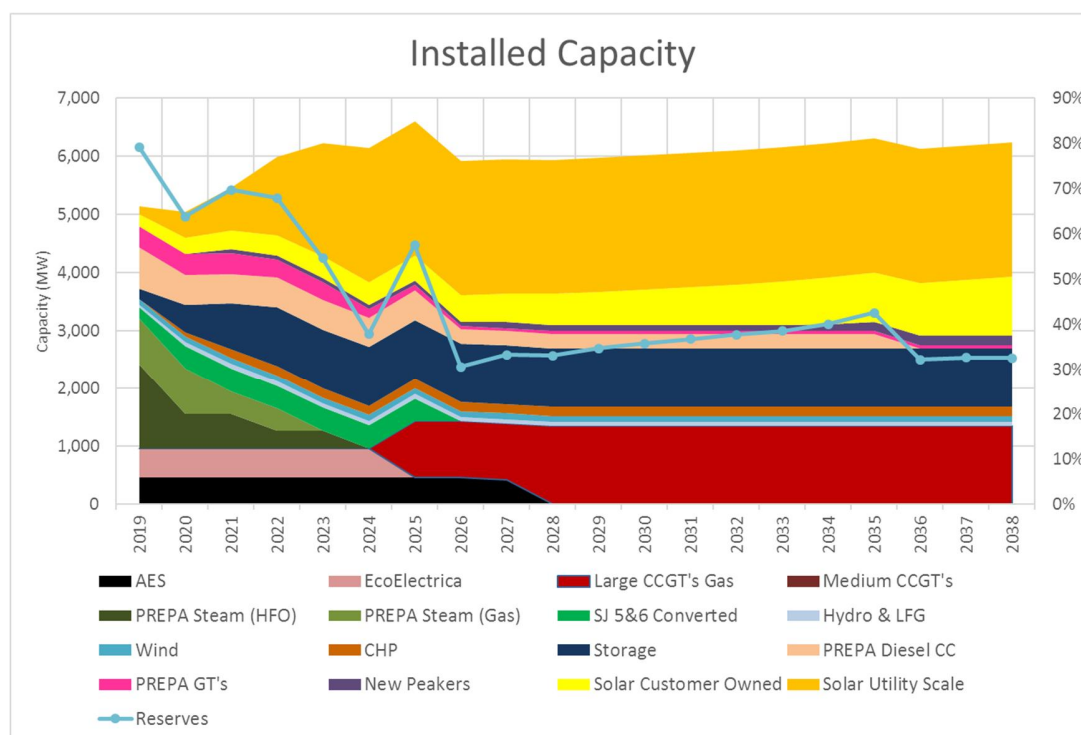
Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Large CCGT's	0	0	0	0	0	0	973	0	0	369	0
Medium CCGT's	0	0	0	0	0	0	0	0	0	0	0
Small CCGT's	0	0	0	0	0	0	0	0	0	0	0
Peakers	0	0	71	0	0	0	0	0	32	0	0
BESS	180	300	300	240	0	0	0	0	0	0	0
Total Dispatchable Additions	180	300	371	240	0	0	973	0	32	369	0
Solar	0	300	300	600	600	360	0	0	0	0	0
Total Additions	180	600	671	840	600	360	973	0	32	369	0

Exhibit 8-75: Scenario 5 Portfolio Capacity Retirements

Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PREPA Steam (HFO)	862	0	301	0	300	0	0	0	0	0	0
PREPA MATS Affected units remaining						0	0	0	0	0	0
PREPA Costa Sur (Gas)	0	393	0	388	0	0	0	0	0	0	0
PREPA Diesel CC & large GTs	0	0	50	0	165	50	307	0	0	0	0
PREPA CC-converted (Gas)	0	0	0	0	0	0	400	0	0	0	0
EcoElectrica	0	0	0	0	0	507	0	0	0	0	0
AES									416	0	0
Total Dependable Gen Retirement	862	393	351	388	465	557	707	0	416	0	0

As PREPA's units and the thermal PPOA's are phased out the operating reserves decline from 64% in 2019 to a low of 31% by 2028 with the retirement of AES. The Planning Reserve Margin of 30% appears to have a binding constraint on the LTCE plan formulation in this Scenario with reserve margins for the system falling near this threshold in 2027-2028 and 2035, however only in 2035 we observe new peaking generation being committed.

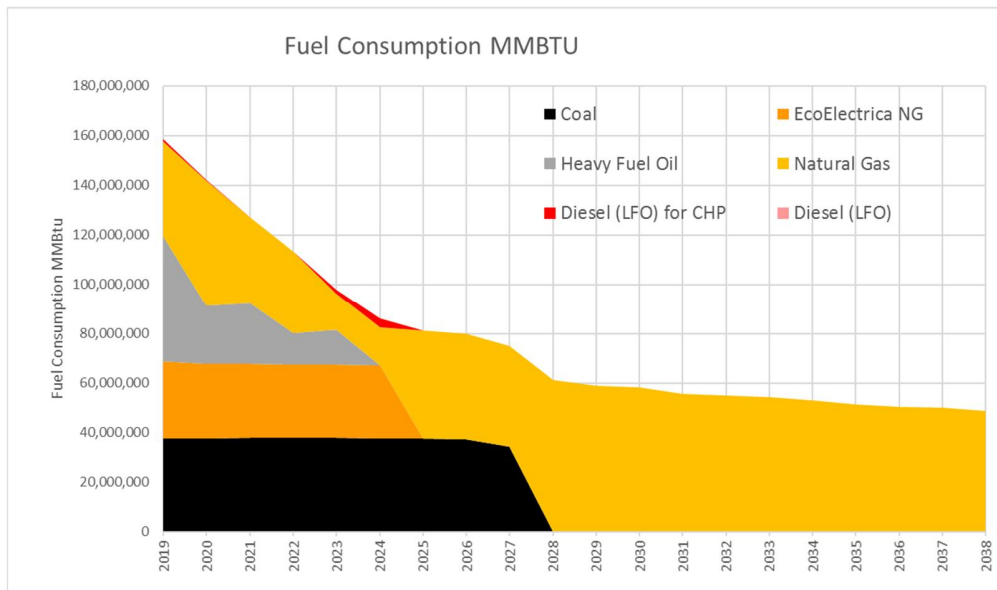
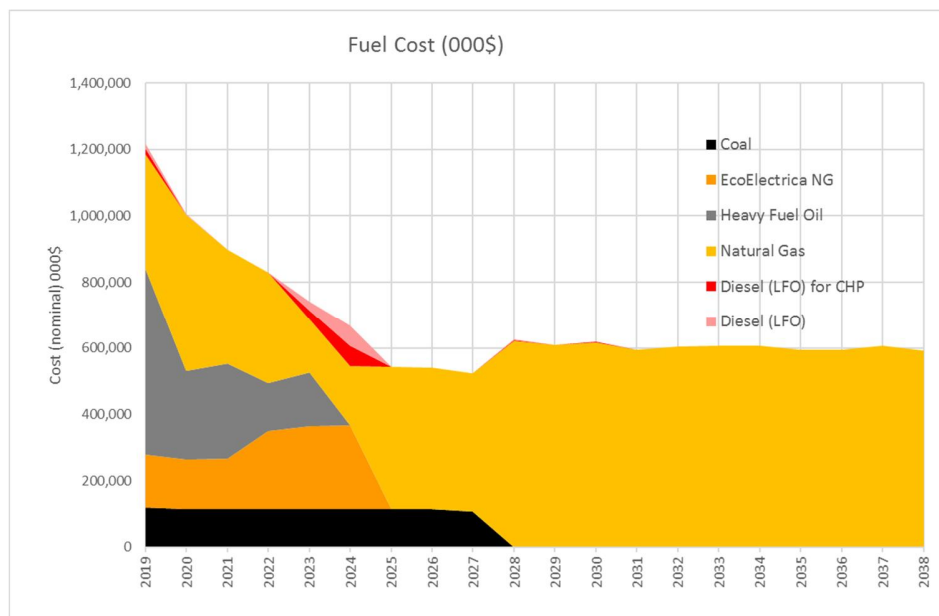
Exhibit 8-76: Scenario 5 Capacity Mix



8.6.2 Fuel Diversity

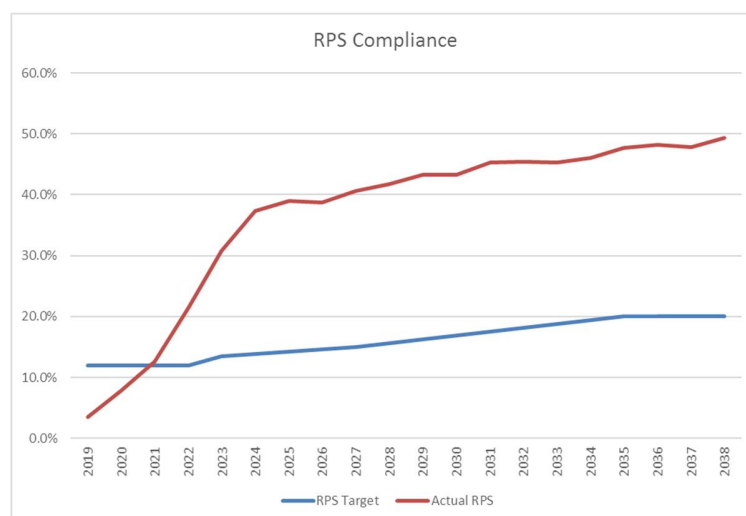
In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines with the retirements of old gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Total fuel consumption drops 69% by 2038 with most of the fuel used coming from natural gas.

Fuel costs decline in line with the overall fall in fuel consumption falling to a low of \$592 million by 2038 (51% below 2019 levels) with all the retirements, including AES.

Exhibit 8-77: Scenario 5 Fuel Mix**Exhibit 8-78: Scenario 5 Fuel Costs**

8.6.3 RPS Compliance

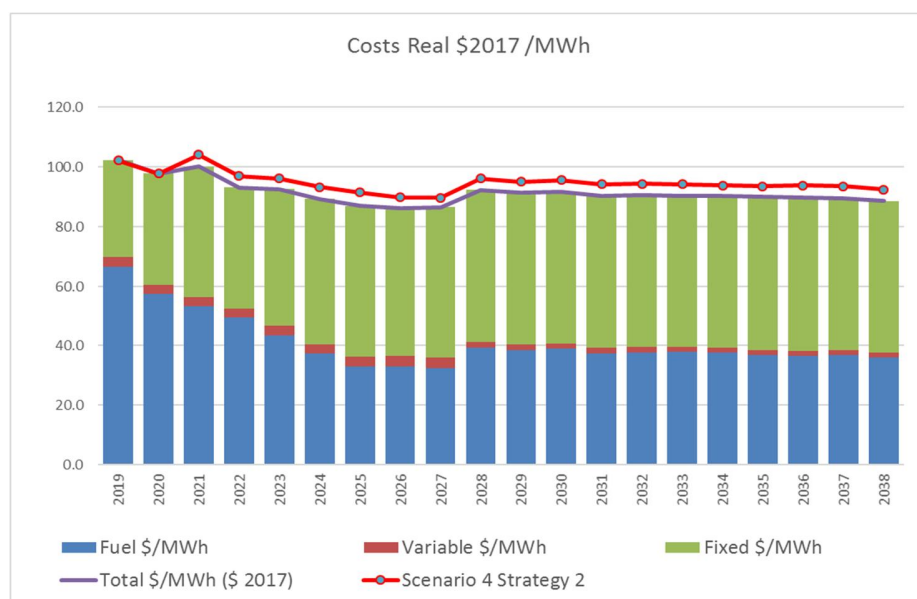
The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met and exceeded in Scenario 5. The plan achieves 49% renewable penetration by 2038, in line to reach the proposed 50% renewable generation by 2040.

Exhibit 8-79: Scenario 5 RPS Compliance

8.6.4 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from \$102/MWh in 2019 to \$86.2/MWh by 2026 (real \$2018), prior to AES Coal retirement, with the addition of solar and storage and the retirement of older generation. The costs increased in 2028 with AES retirement and the addition of the new CCGT. System costs fall in the last 10 years primarily due to falling fuel costs to reach \$88.6/MWh by 2038.

The net present value of all operating costs reaches \$10.1 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is \$14.09 billion. This plan is 3% lower in costs over the study horizon compared to Scenario 4.

Exhibit 8-80: Scenario 5 System Costs

8.6.5 Resiliency (Mini Grid Considerations)

In Scenario 5 plan, the critical loads are not met with thermal resources on most MiniGrids, are not met with local generation while the plan is being developed in 2019 through 2022. After 2022, both loads are met for most MiniGrid regions.

Siemens estimated the potential costs from unserved energy in the case of a major hurricane impacting the transmission system⁶⁵. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a \$2000/MWh cost from unserved energy, which considers that the load shedding will be rotated to minimize impact. The \$2000 is consistent with the cost of unserved energy for residential customers⁶⁶.

Exhibit 8-81 summarizes the economic costs by MiniGrid region for Scenario 5. There are potential costs for most regions, in particular Caguas, Arecibo and Mayagüez North showing the latest potential impact and costs. Total costs for the system are north of \$1.1 billion, \$914 million higher than Scenario 4, basically illustrating the risks to the system of going into a centralized system.

Exhibit 8-81: Cost of Energy Not Served by MiniGrids (NPV Costs \$000)

MiniGrid	Scenario 5	Scenario 4
San Juan-Bayamon	\$ 238,176	\$ 8,874
Ponce	\$ -	\$ -
Carolina	\$ 79,227	\$ 40,737
Caguas	\$ 365,690	\$ 127,850
Arecibo	\$ 210,830	\$ 25,110
Mayaguez-North	\$ 110,049	\$ 518
Mayaguez-South	\$ 71,954	\$ -
Cayey	\$ 66,526	\$ 25,196
Total	\$ 1,142,452	\$ 228,285

8.6.6 Considerations Under High Gas Prices

The Siemens team simulated Scenario 5 under a high gas price case. This resulted in lower gas-fired capacity additions with only two CCGTs being developed, one in Palo Seco and the other one in Costa Sur, both in 2025. Under the high gas case, there is also more peakers added to the system with 374 MW in the planning period, 200 MW higher compared to case with reference gas prices.

⁶⁵ This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of Scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served")

⁶⁶ This value is much lower compared to the VOLL determined for PR, in the range of \$30,000/MWh

There is 180 MW of incremental solar capacity additions supported by an additional 380 MW of battery storage. Solar additions do not change in 2019-2022 with 1,200 MW added.

The overall portfolio costs \$648 million higher compared to the simulation with reference gas prices, making the overall portfolio more expensive than Scenario 4. The risk of having unserved load under MiniGrid operations is somewhat reduced with more peakers with an estimated \$799 million in costs from unserved energy, \$115 million below the simulation with reference gas prices.

8.7 Planning Reserve Margin Considerations

8.7.1 Introduction

The purpose of this subsection is to discuss Planning Reserve Margin (PRM) in more depth.

As was illustrated above the adopted PRM of 30% was found not to be binding under most conditions and in particular for the plans that are considered to contain the recommended decisions; Scenario 4 Strategy 2 with modifications and the ESM plan. However, in this section we review those conditions in which PRM was binding and resulted in new builds. In addition, we provide indication of values to which this PRM could be lowered in the future.

To identify Scenarios where PRM was binding, the reserve margin for all Scenarios and cases was investigated for all years. For cases where the reserves level was close to 30% (PRM) we evaluated if new peaker units were built in response to the low reserve levels. It should be noted here that for the preferred portfolios, S4S2B-M and ESM, PRM was never a binding constraint, i.e. it did not explicitly trigger new peaker units builds. The cases where PRM was a binding constraint are discussed below.

8.7.2 Binding Planning Reserve Margin Cases

Among all the available portfolios, the following cases were found to have binding PRM conditions, which resulted in new builds.

8.7.2.1 S3S3B

In this portfolio, the PRM level dropped to 31.6% in 2024, taking into consideration demand response with a value of 2.6% of peak demand. This drop can be explained due to the retirement of steam (HFO) and diesel CCGT units; a total of 606 MW. In 2025, EcoEléctrica (507 MW) is retired and two (2) new large CCGT gas units (604 MW) were added. In addition, two (2) reciprocating diesel units, 16 MW each, were added in 2025. Because of these additions, the PRM level increased to 39.6% in 2025 (including a demand response of 2.8% of peak demand). It is possible that the peakers were triggered by the reduction in reserves, however most of the additions are economic, as in 2025 new CCGT's can come online.

As indicated earlier, Scenario 3 is a low cost Scenario, as compared with Scenario 4, but it contains levels of renewable generation that will be hard to integrate and assumes deeper reduction on renewable. Hence the entry or not of the peakers above did not change the opinion on this case.

8.7.2.2 S3S3H

In this portfolio, the PRM level was reported as 32.9% in 2026, including a demand response of 2.9% of peak demand. In 2027 and 2028 AES units (454 MW) were retired and one (1) new large CCGT gas unit (302 MW) was added. In addition, ten (10) peaker units with a total of 213 MW were added in the years 2027 and 2028, bringing the PRM to 43.7% in 2028 (including a demand response of 3.1% of peak demand). Again, the PRM could have been binding, but the addition of the CCGT is triggered by economics and retirement of AES.

As indicated earlier Scenario 3 is a low cost Scenario, as compared with Scenario 4, but it contains levels of renewable generation that will be hard to integrate and assumes deeper reduction on renewable. Hence the entry or not of the peakers above did not change the opinion on this case.

8.7.2.3 S4S3B

In the existing S4S3B portfolio, from year 2025 into year 2028 there was a total of 1160 MW of thermal generation retirements at San Juan 6 CC, AES 1&2, and diesel CCGT units, while one (1) new large CCGT gas unit (302 MW) was added. In addition, four (4) peaker units with a total of 115 MW were added in the years 2026 to 2028, bringing the PRM to 31.1% in 2028 (including a demand response of 3.1% of peak demand). In this case the PRM was bidding and was investigated further as described below.

8.7.2.4 S4S1B

In this portfolio, in year 2032 there was a total of 514 MW of thermal generation retirements at PREPA's existing diesel CCGT and GT units. The only thermal new units added in 2032 was a 16 MW diesel reciprocal unit, which brings the PRM to 33.2% in 2032, including a demand response of 3.5% of peak demand. The effect is marginal and towards the end of the period. Also, strategy 1 does not provides adequate levels of local reserves for resiliency.

8.7.2.5 S5S1B

In the existing S5S1B portfolio, in 2027 AES was retired and new generation was added. capacity of 38 MW at AES units, in addition to adding two (2) diesel reciprocating engines with a total capacity of 32 MW. As a result, PRM was reported as 33.6% in 2027, including a demand response of 3.0% of peak demand.

8.7.3 Planning Reserve Margin Sensitivity Analysis

PRM was a binding constraint and triggered new peaker unit additions in limited cases. For most of the years PRM was not binding despite of the relatively low reserve levels for reasons discussed in the previous subsection. To examine the impact of reductions in the PRM, the same portfolio discussed above, S4S3B was assessed for the year 2028 with reduced levels of reserves, as discussed below:

1. Control Case: this case represents the original conditions in portfolio S4S3B, i.e. no changes made. As mentioned previously, the PRM level is 31.1% (including 3.1% of demand response) and without any unserved load reported.
2. The new peaking units built in 2027 and 2028 were removed 115 MW. The units include:

- a. Two (2) Aero LM6000 units: each unit has a capacity of 39 MW and they were added in 2027 and 2028.
- b. One (1) Aero GE LM2500 unit: this peaker unit has a capacity of 21 MW and was built in 2027.
- c. One (1) RICE: this unit has a capacity of 16 MW and was built in 2028.

Because of not building these four peaking units, the PRM level dropped to 26.9%. However, no unserved load was reported. Hence in principle a 27% PRM could have been selected and the units above possibly may not have been built.

3. In addition to not including the generation above, the Cambalache CT2 and CT3 were retired earlier (165 MW) in 2028. As a result, the PRM level dropped to 23.2%, and an unserved load of 102 MWh over 8 hours was reported. The total reported savings for this case is estimated to be \$31.3 million, while the unserved energy cost is \$3.1 million. However, PREPA's planning limit of 4 loss of load hours (LOLH) is exceeded. It should be noted that for this case, all the unserved load is reported in Carolina Area. Based on the above a PRM of 23% would be aggressive.
4. In this final test two (2) peaker GTs (100 MW) at Mayagüez were also removed. The reserve dropped under 20% and there was 3621 MWh of unserved load over 123 hours. Not only the unserved duration greatly exceeds the 8 hour limit, but also the unserved load cost (\$109 million) exceeds the potential savings (\$35.3 million). For this case, the entire unserved load is reported in Carolina and Bayamon Areas (mostly in Carolina).

Siemens is of the opinion that the PRM of 30% was adequate for this study, however, it was desired to investigate the impact of lower PRM in the LTCE optimal calculations to identify conditions in which PRM becomes a binding constraint. Therefore, analysis was conducted again for portfolio S4S3B with a PRM target value of 20%.

The LTCE resulting from this optimization had in fact higher levels of reserves reported compared to previous solutions in which the PRM target was set to 30%. This increase in reserve levels despite using lower PRM target is mainly caused by the optimization algorithm that was able to find a slightly better solution in which the PRM again is not a binding constraint and confirmed that it had minimal impact on the overall results. Further review of this run identified that in the years 2026 to 2030 there was a net capacity increase of 197 MW, which resulted in increasing the PRM level from 44% to 54%. On the other hand, in the years 2030 to 2032 there was a net capacity reduction of 477 MW in the form of retirements, which resulted in reducing the PRM level from 54% to 30%.

Based on the sensitivity analysis results presented above, it can be concluded that PRM does not have a noticeable impact on the overall solution even when PRM target is reduced to relatively low values, e.g. 20%. The higher reserve levels and lower overall total cost, which were achieved with the 20% PRM target imply that PRM was not a binding constraint and did not trigger new builds.

Part

9

Caveats and Limitations

As was explained before in this report, the 2019 IRP is not a classical IRP designed to identify the least cost approach to address the expected gap between load and resources and maintaining a desired Planning Reserve Margin (PRM), but rather produce a plan that satisfies the objectives of providing a service that is customer centric, financially viable, is reliable and resilient, and promotes economic growth. These objectives are to be satisfied on a context of significant declines in the load and of PREPA's current fiscal situation as a debtor under the Title III of the PROMESA Act, which requires PREPA to follow a path to comply with healthy financial utility practices. In addition, the devastation to Puerto Rico's electrical infrastructure from the 2017 Hurricanes forced PREPA to rethink its entire system design, including resources planning addressing the following:

- Existing aging generation infrastructure that burns mostly heavy fuel oil, has poor reliability, does not meet all environmental regulations (e.g. MATS), and is inflexible, which limits the incorporation of renewable resources.
- Current and forecasted industry trends showing a reduction in the cost of renewable resources, especially solar photovoltaic (PV) and bulk battery storage.
- Achieve compliance with the Renewable Portfolio Standard (RPS) mandate.
- Shift from centralized generation located in the south of the island to a more decentralized generation mix, particularly for achieving a more resilient electric service.

Taking in consideration the above, through input received during a series of Stakeholder Workshops, discussion with PREPA staff, and Siemens own knowledge and experience with resource planning, the PREPA and Siemens project team defined a number of aspects that the resource planning resulting from this IRP must address. These aspects are contained in the definition of the Strategies, Scenarios and Sensitivities presented in this IRP. The development of these strategies, scenarios and sensitivities required the formulation of assumptions and forecasts, which are also presented in this report.

It is noted that the modeling done as part of this IRP was performed following electric industry standards and using industry accepted resource planning tools, like AURORAxmp. However, the IRP analyses considered a large number of options and uncertainties, taking into consideration formal and informal input from both PREPA and a large number of stakeholders. The inputs used for these analyses, simulations and modeling were based on the aforementioned assumptions and forecasts. Hence, the modeling results will be valid while the assumptions are achieved, and the forecasts are fulfilled.

Considering the conditions mentioned above, there are a series of main caveats and limitations of the IRP, which are summarized in this part. Following, we present a list of these key caveats and limitations:

1. The IRP evaluates the highest public good and the protection of the interests of the residents of Puerto Rico, which may not necessarily be identical to the interests of PREPA if viewed from a narrow utility perspective.
2. The IRP does not directly address specific asset technology, asset optimization, fuel optimization, procurement, interconnection issues, new contracts, contract re-negotiation, collective bargaining rights, site specifics, or ownership.
3. The IRP does not set rate structures.
4. The IRP does not directly address the debt restructuring process or privatization plans.
5. The implementation of the Puerto Rico Electric System Transformation Act is a separate process outside the accelerated timeline of developing the IRP.
6. The IRP was conducted with extensive inputs from a broad group of stakeholders including the public, the customers, under an accelerated timeline and in parallel with many other related activities but may not consider or fully consider all externalities that are critical for the Preferred Resource Plan implementation or execution.
7. From the Stakeholder Workshops, it was found that stakeholders generally preferred a strategy founded on distributed (Strategy 2) rather than centralized (Strategy 1) supply resources for Puerto Rico's situation because it provides a more resilient grid, as the supply is located closer to the load. Participants viewed Strategy 3 (combination of centralized and distributed generation) as a short- or medium-term step to Strategy 2. Following the preferences of the stakeholders, the IRP analyses focused on Strategies 2 and 3 and only one case was run with Strategy 1. It is noted that the larger centralized resources aligned with Strategy 1 usually provide lower costs of energy than distributed resources, but depend on the reliability of the transmission system during a major event like a hurricane. Considering the experience with the 2017 hurricanes in Puerto Rico, a distributed resources strategy was selected for providing resiliency to the electric service, even though it could result in higher costs.
8. The load served by PREPA is expected to significantly decline over the IRP's planning horizon due to a combination of expected base load reduction (driven by population and economic changes), energy efficiency gains, and demand side resources. Even though the modeling was performed considering three load forecast levels (High, Base and Low) and the Preferred Resource Plan is expected to work well in all of them, a drastic change in these assumptions could affect the IRP results and require significant changes in such plan. Hence, it is important to review the IRP plan in the term of three years stated by Act 57-2014 for verifying these assumptions.
9. The main sources of data used for the load forecast included Moody's Analytics, the International Monetary Fund, World Bank, the U.S. Census Bureau, Federal Reserve of Economic Data of St. Louis (FRED), and Puerto Rico's Federal Management

- Oversight Board (FOMB). In particular, Siemens used FOMB historical and forecasted data for GNP and population for the IRP load forecast. Siemens assumed that the data from these sources is reliable and correct. If, in the future, it is found that this data or any part of it is incorrect, a revision of the load forecast, and the IRP modeling shall be done for correcting the IRP results.
10. The environmental regulations determined by Siemens and PREPA to be potentially significant and factored into the IRP analysis include federal air regulations, water regulations, and local policy dictating targets for renewable and alternative energy. . A significant change in these assumptions could affect the IRP results and require changes in such plan. Therefore, it is important to review the IRP plan in the term of three years stated by Act 57-2014 for verifying these assumptions.
 11. The conventional generation technologies (CCGTs, GTs, RICE, etc.) included in the IRP are considered representative and selected for modeling purposes. There are multiple developers that can provide equivalent equipment and the findings in the IRP should not be considered prescriptive of a particular generation design. This technologies selection was the result of Siemens screening of available new generation resources that allow for system flexibility and reliability, including the integration of large blocks of renewable capacity, primarily solar.
 12. The location of the peaking generation is a function of the needs for local support, which in turn are a function of the available generation and load. If there are changes with respect of the assumptions in this document, PREPA should have the flexibility to adjust and redeploy these units.
 13. The IRP considers that all new renewable generation will have market prices adjusted to Puerto Rico conditions. This implies that all the pre-existing contracts associated with projects that have not started construction, are voided and new fully competitive RFP processes are advanced. For the projects in operation or pre-operation, Siemens assumed fixed price conditions based on current contracts prices. If these marked prices for new generation are not achieved, the LTCE plans are directly affected, probably resulting in much lower integration of renewables with the system.
 14. The IRP assumes an accelerated timeline for solar and storage projects, assuming fast track of permitting, proper submittal of project design for evaluation by PREPA, and securing the land for the interconnection line and facilities. In addition to unforeseen events that could delay these tasks, this timeline could be delayed by limitations on the amount of annual installations that can effectively be carried out in parallel maintaining the continuous operation of the power system.
 15. In the case of utility scale storage, it is noted that the amount recommended in the IRP is much higher than the total capacity currently installed in the whole United States. This represents an installation never done before in a power grid, especially nor in an isolated system like the one in Puerto Rico. Hence, it is foreseen that the first storage projects will take more time to be developed and integrated with the power system, as they will be the pilot projects of very large bulk storage in Puerto Rico and the main land. Particularly, the learning curve will be defined with those projects that have to be developed maintaining the reliability and continuity of the service in Puerto Rico.

16. For maintaining the reliability of the system, PREPA should not commission neither allow the interconnection of PV solar or wind projects to the grid until the required corresponding energy storage component be commissioned and interconnected in full compliance with the energy storage technical requirements. The solar PV projects shall still comply with the MTRs related with frequency ride through, voltage ride through, reactive power capability and voltage regulation in addition to their full compliance with the frequency regulation and frequency response requirements to be met by either separate or integrated energy storage. This approach is expected to foster competition and innovation while at the same time ensuring that the required regulation and energy shifting will be available for the PV integration before its interconnection.
17. The IRP recommends the retirement of the existing steam generating fleet at different times, including the Aguirre 1 & 2 units in 2019. However, these recommendations are based on other prerequisite developments which include the forecasted reduction in load, assumed levels of reliability of the remaining of the existing fleet at the time of retirement, and the commissioning of the new generation resources. Hence, the retirement of existing generating units shall be only implemented after all these prerequisites have been met, especially that all new resources are fully operational, and is evidenced by the low to zero dispatch of the generation.
18. All project descriptions, schedules and cost estimates should be considered a best estimate at this point in time. Most of the recommended projects are at very preliminary stages of scope formulation and as such have a high degree of uncertainty associated with the estimates. In addition, PREPA may recommend changing these action items in future years should new units not become operational in time to support the planned retirements, or if customer energy consumption, or vendor responses to solicitations substantially differ from those anticipated and described in this IRP.
19. The provided installation dates for equipment are a function of multiple assumptions including permitting, engineering and construction times. For those cases that the equipment is committed by the earliest assumed entry, the dates should be read as the reported date or earlier.
20. FOMB's "critical project" process under Section 503 of PROMESA is a separate process outside the accelerated timeline of the IRP development.
21. All new Distributed Generation connected to the system was assumed to comply and must comply with the new IEEE Standard 1547-2018 (IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces)
22. The IRP is a planning tool to be used as a guide for the development of future resources in Puerto Rico and may not have all the details necessary for the actual RFP issuance, contracting, and implementation.
23. The IRP is not a Distribution Master Plan that would require a level of effort similar to the development of this IRP. Thus, distribution investments are considered at a very high representative level.

Part
10

Action Plan

This section summarizes the recommended actions that the Energy Bureau should approve and PREPA should undertake in the period from 2019 to 2023 to implement the Preferred Plan identified in the IRP (Action Plan). This plan describes an ambitious program of investment and restructuring of the entire PREPA utility system to better prepare the island to withstand and recover from future weather and service disruption events and to position the island to adapt to future changes to the islands economic conditions and power requirements. The Action Plan is divided into four subsections for:

1. **Supply Resources** – including new and existing generation, purchased power, energy storage and fuel infrastructure.
2. **Transmission System** – including changes to the system to support the hardening of the transmission system and the enable the MiniGrids.
3. **Distribution** – including changes to the system to support the hardening of the transmission system and the enable the MiniGrids and the incorporation of rooftop PV.
4. **Energy Efficiency and Demand Response** – including recommended programs and benefits.

Each subsection describes the principle actions, timetables, capital expenditures, permitting issues and other regulatory approvals that are required to implement the plan. All project descriptions, schedules and cost estimates should be considered a best estimate at this point in time. Most of the recommended projects are at very preliminary stages of scope formulation and as such have a high degree of uncertainty associated with the estimates. In addition, PREPA may recommend changing these action items in future years should new units not become operational in time to support the planned retirements, or if customer energy consumption, or vendor responses to solicitations substantially differ from those anticipated and described in this IRP. Please refer to the Caveats and Limitations section in Part 9 of this IRP for additional details.

PREPA currently plans to solicit bids from vendors for PPOAs, facilities lease agreements, or similar commercial structures where the bidders would Design, Build and Finance, or Design, Build, Finance, Operate and Maintain the projects and sell power or use of the project to PREPA. The estimated overnight capital expenditures are provided for most of the projects listed. These estimated capital expenditures provide an indication of the magnitude of the investments that would be financed by potential vendors. The vendors financing costs would then be paid through the proceeds from a PPOA or other commercial agreement and ultimately become part of PREPA's operating expenses, as opposed to PREPA capital expenditures.

10.1 Supply Resources

10.1.1 Overview and Principal Recommendations

Two resource plans provided virtually identical NPV results, the least cost ESM plan and the S4S2 plan which have an NPV difference of less than \$9 million (\$8,747,000 difference for the NPV base cases). While these plans had a number of identical elements, they also had material differences. In order to create a no regrets/minimum regrets Action Plan, it is recommended that PREPA follow the ESM resource plan and add preliminary activities from selective elements of the S4S2 plan that will provide greater flexibility than either plan alone and a hedge against potential issues that may arise with the planned development new resources, the continued reliance on PREPA's aging generation fleet and the changes in the future system demand that must be served. The following supply resource actions summarize the ESM plan action and then, separately, the recommended additions drawn from the S4S2 plan. The action plans include new generation and fuel infrastructure resources, modifications to existing resources, including modifications to the existing PPOA with EcoEléctrica.

All the new generation additions will be solicited as PPOAs. The capital expenditures presented below are provided as a reference of estimated overnight capital expenditures costs of a PPOA developer.

10.1.1.1 Solar Photovoltaics (install 900 MW to 1800 MW)

PREPA plans to install at least 900 MW and up to 1,800 MW of solar PV in the first 5 years of the plan (2019 to 2023). RFPs will be issued for blocks of approximately 250 MW of solar PV. We expect that responses to each RFP block will include multiple projects of varying capacity. The actual amount installed will depend on the bid pricing received and PREPA's internal ability to interconnect the projects. PREPA plans to solicit the solar PV projects as PPOAs and may solicit additional, alternative commercial options. In addition, PREPA plans to consider potentially soliciting the solar PV as a standalone project, solar PV plus BESS in a combined bid and BESS as a standalone bid. A further discussion of the battery solicitations is discussed in the next sections.

The minimum planned solar PV addition of 900 MW aligns with the results from the LTCE for the ESM plan. The solar PV addition of 1800 MW addition aligns with the S4S2 plan. If the PREPA determines that it can practically install more than the planned 900 MW and it finds that solar PV bid prices are at or below the forecasted prices, and remain favorable relative to the fossil fuel pricing, PREPA will attempt to install up to the 1800 in the first four years of this plan as called for in the S4S2 LTCE plan. The annual PV additions from the ESM plan are noted in the Exhibit below. These values should be considered the minimum targeted installation.

Exhibit 10-1: ESM Annual Solar PV Additions

	2019	2020	2021	2022	2023
Solar PV Additions (MW)	0	0	240	480	180
Cumulative Additions (MW)	0	0	240	720	900
Capital Expenditures (\$M)	-	-	\$343	\$678	\$251

The annual PV additions from the S4S2 plan are noted in the Exhibit 10-2 below. These values should be considered an upper limit to the targeted installation. Scenario 3 that considered a deeper reduction in cost of renewable and high capability to interconnect had higher values (see Part 8), but these are considered unlikely to be feasible.

Exhibit 10-2: S4S2 Annual Solar PV Additions

	2019	2020	2021	2022	2023
Solar PV Additions (MW)	0	300	300	600	600
Cumulative Additions (MW)	0	300	600	1200	1800
Capital Expenditures (\$M)	-	\$452	\$428	\$848	\$837

The ESM plan under base load forecast achieved 24% RPS compliance by 2038, should the regulation in Puerto Rico change and require 50% RPS compliance by 2040 a minor change would be required for the ESM case and in 2023 approximately 430 MW of solar PV would be required instead of 180 MW. The rest of the required changes to meet the 50% target would occur beyond the 5 year timeframe of the action plan.

10.1.1.2 Battery Energy Storage (install 600 MW to 900 MW)

PREPA plans to install at least 600 MW and up to 900 MW of BESS in the next five years. The amounts of BESS which will be installed is correlated to the capacity of solar PV installed and the resources required for the MiniGrids. RFPs will be issued for blocks of BESS of approximately of 150 to 200 MW. As noted in the prior Solar PV discussion, PREPA plans to consider potentially soliciting the BESS as a standalone project, solar PV plus BESS in a combined bid and solar PV as a standalone bid. The annual BESS additions from the ESM plan are noted in the Exhibit below. These values should be considered the minimum targeted installation.

Exhibit 10-3: ESM Annual BESS Additions

	2019	2020	2021	2022	2023
BESS Additions (MW)	20	100	160	160	160
Cumulative Additions (MW)	20	120	280	440	600
Capital Expenditures (\$M)	\$24	\$109	\$163	\$153	\$147

The annual BESS additions from the S4S2 plan are noted in the Exhibit below. These values should be considered an upper limit to the targeted installation.

Exhibit 10-4: S4S2 Annual BESS Additions

	2019	2020	2021	2022	2023
BESS Additions (MW)	180	300	300	120	0
Cumulative Additions (MW)	180	480	780	900	900
Capital Expenditures (\$M)	\$216	\$328	\$308	\$115	-

There is no difference on the installations on the ESM case if the target RPS is changed to 50% RPS by 2040.

10.1.2 Modify and Retire Existing Resources

San Juan 5&6 Combined Cycle (CC) Conversion to Natural Gas (2x200MW)

This conversion was considered a committed action in developing this IRP and is currently an ongoing activity. The fuel conversion of San Juan 5&6 will use a ship-based liquefied natural gas (LNG) terminal. This project includes a supporting fuel infrastructure project. Each of these units has a capacity of 200 MW with a combined capacity of both units of 400 MW. This action is recommended in both the ESM and the S4S2 plans. Based on the current project schedule, the converted units are expected to reach commercial operation by June 2019. There are no capital expenditures for the conversion as the contract for conversion was structured as a capacity payment.

Mayagüez 1, 2, 3, 4 Peaker Conversion to LNG Natural Gas (4x50MW)

This conversion was considered a committed action in developing this IRP and is currently an ongoing activity. The existing aeroderivative Peakers, Mayagüez 1, 2, 3, 4 (4 units at 50MW each) are to be converted to use natural gas. The use of natural gas will require the addition of LNG infrastructure for a ship-based liquefied natural gas (LNG) delivered to a new Mayagüez terminal. The conversion of these four existing units was included in the ESM plan as well as the installation of four new, containerized natural gas fueled mobile peakers (23 MW each and installed by 2021), but these units will be deployed in the north in support of the Mayagüez North MiniGrid. While the S4S2 plan did not include the conversion of the aeroderivative units, the conversion of these units would be a minor adjustment to the S4S2 plan and it would allow an early use of the available LNG prior to the commissioning of the 302 MW CCGT unit that this plan recommends. Based on the current project schedule, the converted units are expected to reach commercial operation in 2022 with an estimated capital expenditure for the conversion of the four units of \$5 million.

EcoEléctrica Contract Renegotiation and Extension

The PPOA contract renegotiation with EcoEléctrica is considered a committed action in developing this IRP and is currently an ongoing activity. PREPA must renegotiate the PPOA to both modify the commercial terms and the operational flexibility of this PPOA in order to make the EcoEléctrica PPOA an economic resource in the future PREPA system that will include increasing amounts of renewable generation. However, there is no assurance that the contract can be successfully renegotiating and extending the current contract which is set to expire in 2022. The best alternative to replace the EcoEléctrica resource, should the renegotiation and extension not be successful, is with a new gas fueled 302 MW CCGT plant at Costa Sur described below under new resources. This action is recommended for both the ESM plan while the S4S2. However, the ESM plan assumed a successful negotiation and extension of the contract and the S4S2 plan assumed the contract could not be successfully renegotiated and was replaced by a new 302 MW CCGT unit at Costa Sur.

San Juan Generator Conversions to Synchronous Condensers

With the retirement of PREPA older steam units and the introduction of greater inverter based generation, studies carried out under this IRP (see Appendix 1) indicate that the PREPA system may require synchronous condensers to increase the short-circuit level and provide minimum levels of voltage stiffness for the inverter based resources to operate reliably. This is assessed in the Industry by determining the Short Circuit Ratio as the ratio of the short circuit level in the system to the installed inverter based resources and typically values below

1.5 are problematic. Without the synchronous condensers the ratio may be under 1.0 for PREPA resulting in an unstable system.

San Juan 9 and 10 are assumed out of service for this IRP analysis and designated for either retirement or limited use. Both units are candidates for potential immediate conversion to synchronous condensers. Within the next 5 years, the ESM plan also calls for the retirement of San Juan 7 and 8. Palo Seco 3 and 4 are designated for retirement in the ESM plan in 2024. After retirement, all these units will be considered candidates for potential conversion to synchronous condensers. The specific units selected for conversion the schedule for their conversion and the costs of conversion will require additional study. Dependent on the results of a study of the synchronous condenser needs and costs, PREPA expects to potentially convert one and possibly both of San Juan 9 and 10 to synchronous condensers within the first five years of this plan (by 2023). The estimated time to convert a unit is approximately six months. Without the benefit of the results of the study, Siemens has estimated the commercial operation date of the conversion of San Juan 10 in January 2022 and the conversion of San Juan 9 in 2023. Siemens has also developed a very high-level capital expenditure estimate of \$9 million per unit for the conversion based on an EPRI study⁶⁷.

10.1.3 Unit Retirements

In the ESM the following unit retirements are recommended in the first five years of the plan, subject to the availability of the new generation resources, and the realization of the other assumptions in the capacity expansion plan. Please see Part 8 for more details.

Exhibit 10-5: Unit Retirements

Unit	Last Year in Service
Frame 5 Peakers	2019 to 2021
Aguirre ST 1	2019
Aguirre ST 2	2020
Costa Sur 6	2020
Costa Sur 5	2021
San Juan 7&8	2023

10.1.4 Install New Resources

Palo Seco CCGT (302 MW F-Class)

The ESM, S4S2 plans call for a new natural gas fueled 302 MW CCGT at Palo Seco by January 2025. January 2025 is also the earliest practical date the unit could be in service. This unit is also applied to all but select cases of Scenario 1 cases (no new gas). However, to meet this operation date the project would need to begin immediately. The commercial operation for this unit is estimated to be January 2025 with an estimated capital expenditure of \$291 million.

⁶⁷ Turbine-Generator Topics for Power Plant Engineers: Converting a Synchronous Generator for Operation as a Synchronous Condenser. EPRI, Palo Alto, CA: 2014. 3002002902.

Costa Sur CCGT (302 MW F-Class)

Under all cases, including the ESM, unless the contract with EcoEléctrica is successfully renegotiated and extended, it is recommended that EcoEléctrica supply be replaced by a new natural gas fueled 302 MW CCGT at Costa Sur. However, the EcoEléctrica PPOA is scheduled to expire in 2022 and it has been estimated that the earliest that a CCGT could be in service at Costa Sur is January 2025. Therefore, to preserve this earliest potential operation date for the CCGT, PREPA must start immediately and proceed with the preliminary activities for developing the CCGT in parallel with the efforts to renegotiate the EcoEléctrica PPOA. If the EcoEléctrica PPOA renegotiation is successful, the need for this unit will be reevaluated based on the load growth and the progress of the other generation development projects. The commercial operation for this unit is estimated to be January 2025 and an estimated capital expenditure of \$291 million.

Yabucoa CCGT (302 MW F-Class)

The ESM plan calls for a new natural gas fueled 302 MW CCGT at Yabucoa by January 2025. January 2025 is also the earliest practical date the unit could be in service. This unit is also called for in two Scenario 4 cases and it is needed if the land based LNG cannot be developed for the San Juan plant or the high load growth materializes. However, to meet this operation date the project would need to begin immediately. The commercial operation for this unit is estimated to be January 2025 and an estimated capital expenditure of \$291 million.

Mayagüez CCGT (302 MW F-Class)

The ESM plan does not call for the development of a combined cycle plant at Mayagüez. However under various situations, Scenario 4 calls for a new 302 MW natural gas fueled CCGT at this site by 2028. It is recommended to advance preliminary engineering and permitting of this option as a hedge against inability to develop the generation at other sites and to take advantage that under the ESM a ship-based LNG is developed here.

San Juan Small CCGT – LPG/NG (3x38MW)

These units are needed to provide generation in the North as a hedge against any of the existing aging generation units in the North (Palo Seco 3&4 or San Juan units 7, 8 and 9) fail prematurely, prior to their planned retirements, as did San Juan 10. The units will be designed and permitted to burn either LPG or natural gas providing additional fuel flexibility. The units will be located in the North in the San Juan area but may be located at a site other than the San Juan plant. Preliminary discussion with vendors indicated these units can be permitted and constructed very rapidly with an estimated commercial operation date of January 2022. The estimated capital expenditure for the three units is \$203 million, but there is uncertainty with respect of the actual technology to be deployed as offers reviewed vary widely.

Mobile Gas Turbine Peaking Units (18x23 MW)

The ESM plan calls for installation of 18 GTs, of 23 MW each, distributed at five different plant locations around the island with preference for those locations where the exiting Frame 5 21 MW units are located. These new units will be capable of burning containerized natural gas delivered by truck with onsite tankage. The units are required to provide reliable distributed

generation to serve critical and priority loads within the MiniGrids. The S4S2 case also called for 16 of these 18 units at the same plant locations. Since these are mobile generator units, the additional two units recommended with the ESM case will provide PREPA greater flexibility to move the units to other MiniGrids if needed. The units will be distributed as shown in Exhibit 10-6 below:

Exhibit 10-6: Locations of Mobile 23 MW GTs

Location	Number of Units
Jobos	2
Mayagüez North	4
Carolina (Daguao)	5
Caguas (Yabucoa)	5
Cayey	2
Total	18

These small GTs should be placed in service as soon as practical. The ESM and S4S2 plans assume a January 2021 commercial operation date and an estimated capital expenditure for all 18 units of \$384 million.

10.1.4.1 New Natural Gas Infrastructure

San Juan Land-Based LNG Terminal

This new LNG terminal is recommended as a preferred option for supplying large quantities of natural gas to San Juan and Palo Seco Plant. The project would provide a land-based (onshore) LNG storage and vaporization facility near the San Juan plant supplied with LNG carrier delivery directly to onshore tanks. The project also includes a natural gas pipeline to the Palo Seco Plant to support the new 302 MW CCGT recommended for the site. The ESM plan assumes operations by 2025 with delivery to the San Juan plant and via pipeline to the Palo Seco plant. Any delays in the development of the land-based LNG supply is assumed to be covered by ship-based LNG. Based on input from PREPA, the estimated capital cost of this land-based facility, with a pipeline to Palo Seco, is \$492 million. Siemens has assumed the LNG terminal is being developed to supply 650 MW of generation and Note that in as much as the generation may use only a portion of the available terminal capacity, it was assumed to bear only its portion of the total terminal costs.

Yabucoa Ship-Based LNG Terminal

The addition of an LNG terminal at Yabucoa is part of the least cost ESM plan that calls for the development of a 302 MW CCGT and the LNG terminal at the site. As noted previously, the LNG terminal and the new CCGT are also called for in multiple S4S2 cases. The commercial operation of the terminal would coincide with the commercial operation of the new CCGT unit in January of 2025. However, to meet this operation date the project would need to begin immediately. Siemens estimates the capital expenditures for ship-based LNG delivery to Yabucoa to be \$215 million.

Mayagüez Ship-Based LNG Terminal

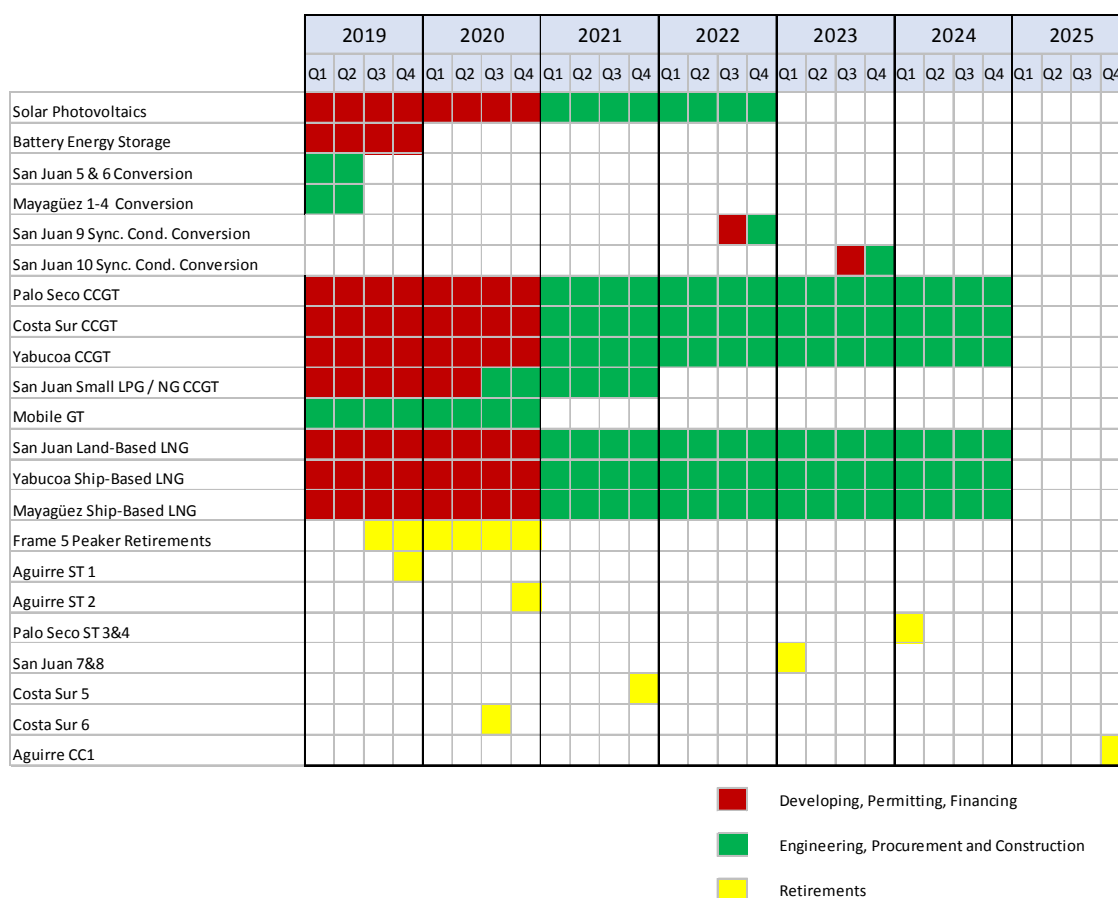
The addition of a LNG terminal at Mayagüez is recommended to allow the conversion of the existing Aero-derivative GTs in place to burn natural gas. In addition, the infrastructure is recommended as a hedge against problems with development of the new generation at other

locations that require the development of a new 302 MW natural gas fueled CCGT at this site. Finally, the LNG terminal and CCGT were called for as part of the S4S2 plan. The recommended commercial operation date adopted the date called for in the S4S2 plan of January 2028. Siemens estimates the capital expenditures for ship-based LNG delivery to Mayagüez to be \$215 million.

10.1.5 Summary Timetable

A summary timetable for the projects discussed above is shown in the Exhibit 10-7 below.

Exhibit 10-7: Summary Schedule



10.1.6 Summary of Capital Expenditures

A summary of the estimated overnight capital costs is provided in the Exhibit 10-8 below.

Exhibit 10-8: Summary of Capital Expenditures for 2019 to 2023

Values in table are in current millions of dollars

Project	2019	2020	2021	2022	2023
Solar Photovoltaics	-	-	\$343	\$678	\$251
Battery Energy Storage	\$24	\$109	\$163	\$153	\$147
San Juan 5 & 6 Gas Conversion	-	-	-	-	-
Mayagüez 1-4 Gas Conversion	\$5	-	-	-	-
San Juan 10 Sync. Cond. Conversion	-	-	-	\$9	-
San Juan 9 Sync. Cond. Conversion	-	-	-	-	\$9
Palo Seco CCGT	-	-	-	-	-
Costa Sur CCGT	-	-	-	-	-
Yabucoa CCGT	-	-	-	-	-
San Juan Small LPG / NG CCGT	-	-	-	-	-
Mobile GT	-	-	\$384	\$104	\$73
San Juan Land-Based LNG	-	-	-	-	-
Yabucoa Ship-Based LNG	-	-	-	-	-
Mayagüez Ship-Based LNG	-	-	-	-	-
Total	\$29	\$109	\$890	\$944	\$480

Total for all Projects 2019 to 2023 \$2,452

10.1.7 Permitting and Regulatory Activities

This IRP require that all major expenditures and contracts commitments referenced in this document, the approval from the PREB.

In addition, the action plan described above will require a host of additional approvals from the government of Puerto Rico and federal government agencies. The approval includes air, water and land use permits associated with the design, construction and operation of the generating projects. A partial list of likely permits associated with the new resources and gas infrastructure include:

- EPA and EQB review of New Source Review (NSR) for air emission permitting
- EPA National Pollutant Discharge Elimination System (NPDES) for water permitting
- EQB Water Quality Certification
- Environmental Assessment (EA) or Environmental Impact Statement (EIS) reviewed by various Puerto Rico and federal agencies
- Puerto Rico Office of Permits Management (OGPe) Construction Permits

While PREPA will need to support these applications and permits for all the projects listed, PREPA expects the project bidders will provide vast majority of the work and expenses associated with any required permits.

10.2 Transmission System

In this section, Siemens assessed the capital investments on PREPA's transmission system, and determined the implementation action plan including project priorities, capital investment schedules, and timetables.

10.2.1 Overview and Principal Recommendations

PREPA has identified a comprehensive list of transmission system related projects to both bring the existing transmission facilities up to current or new standards as well as the new construction and infrastructure hardening of transmission lines (underground cables) and transmission substations for MiniGrid operations. This forms a large portfolio of transmission capital investments for which a prioritized implementation plan and an estimated timeline is essential.

The projects are mainly focused on enabling PREPA's transmission system to operate as multiple MiniGrids during or shortly after a major event, and before the infrastructure can be restored to integrated system operations.

All projects are categorized by various technical justifications, most of which are directly associated with the formation of MiniGrids, i.e. MiniGrid Main Backbone, MiniGrid Backbone Extension, Interconnection of Critical loads, and Interconnection of MiniGrids. There are some projects under existing infrastructure hardening category and aging infrastructure replacement that are related to the reliable operation of the MiniGrids. Most of the transmission substation projects are related to converting the existing substations into gas insulated substations.

In addition to the MiniGrid directed projects, there is a second major category of projects; the transmission reliability investments that are necessary to bring back PREPA system up to current or new Standards, reconstruct aging infrastructure and allow reliable day to day operations.

Total of five (5) groups of priority; Priority 1 through Priority 5, have been determined by PREPA and assigned to each project. Critical operational and field related construction logistical aspects, such as the possible scheduling Scenarios for the transmission line clearances, were considered by PREPA to assign the projects in their corresponding priority groups related to scheduling. Projects deemed Priority 1 will be assumed to have the engineering/permitting/outage scheduling work start as early as July 2019, with engineering, procurement and construction (EPC) start early 2020, and commercial in-service data as soon as March 2021. Projects in Priority 2 group will start upon completion of EPC work of all Priority 1 projects, with in-service date from 2023 to 2024, and continuing for the remaining priority groups. The above timeline assumption should be considered a high level estimate at this time and should be refined with detailed planning that considers which project tasks can be carried out in parallel without compromising the reliability of the system. The detailed plan also should identify when long lead time items should be ordered, and our current working assumption is that this will occur during the engineering/permitting phase and ahead of EPC start. The action plan focuses mainly on the first 5 years for investment implementation; therefore, the detail list of projects will only show projects identified with Priority 1 and Priority 2.

The confidential Attachment B provides the detailed list of Priority 1 and Priority 2 transmission line and substation investment projects.

10.2.2 Schedule of Capital Expenditures

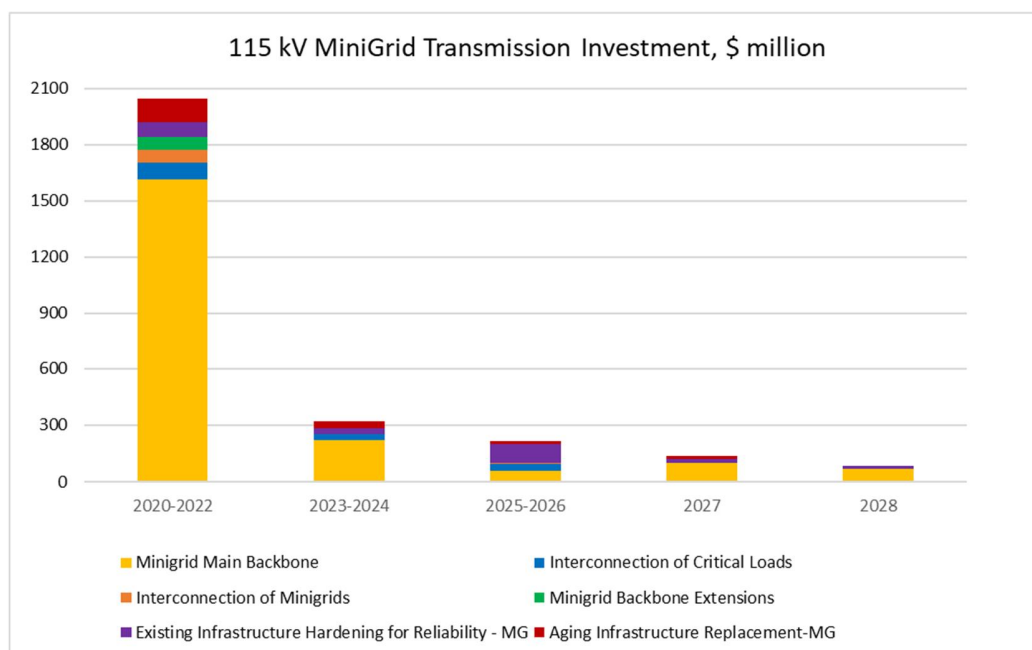
The exhibits below show the schedule of 115 kV and above transmission capital expenditures for MiniGrids over the next 10 years. EPC work starts in 2020 for Priority 1 group projects followed by Priority 2 group projects in 2023 and so on. We have spread the capital investment into three years for Priority 1 projects due to its large total amount of \$2,048 million (Avg. \$683 million per year). EPC work for Priority 2 group projects will start in 2023 and spread into two years, totaling \$322 million (Avg. \$161 million per year).

For the PREPA's transmission system to be operable in MiniGrid mode, and as discussed in detail in Appendix 1 Transmission & Distribution Design of this IRP, additional microgrid controllers and communication infrastructure for Minigrid control system is necessary. The investment expenditure is very small (\$0.135 million per microgrid controller for each MiniGrid or microgrid) compared to the capital investment on transmission projects, and thus will not be listed separately in this section. However, the investment on microgrid control system should be assigned as Priority 1 group so that they will be implemented as early as possible.

Exhibit 10-9. 115 kV MiniGrid Transmission Investment, 2018 \$ million

	Priority 1	Priority 2	Priority 3	Priority 4	Priority 5
Technical Justification	2020-2022	2023-2024	2025-2026	2027	2028
Interconnection of Critical Loads	87.9	31.7	36.0	0.0	0.0
Interconnection of Minigrids	66.8	0.0	6.8	0.0	0.0
Minigrid Backbone Extensions	70.4	0.0	0.0	0.0	0.0
Minigrid Main Backbone	1615.7	220.2	59.1	101.9	70.3
Existing Infrastructure Hardening for Reliability -	80.9	31.5	100.3	20.8	11.1
Aging Infrastructure Replacement-MG	126.0	38.8	11.3	15.5	5.0
Total	2047.7	322.2	213.5	138.3	86.4

**Exhibit 10-10. 115 kV MiniGrid Transmission Investment,
2018 \$ million**

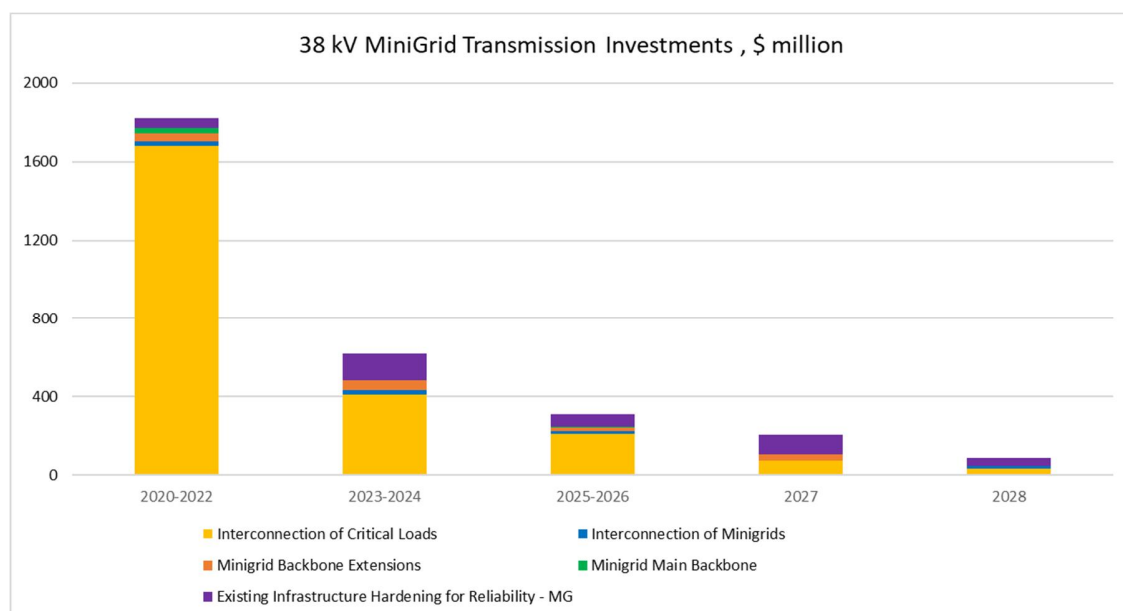


Exhibits below show the schedule of 38 kV transmission capital expenditures for MiniGrids over the next 10 years. EPC work starts in 2020 for Priority 1 group project followed by Priority 2 group projects in 2023 and so on. Again, we have spread the capital investment into three years for Priority 1 projects due to its large total investment of \$1,821 million (Avg. \$607 million per year). EPC work for Priority 2 group projects will start in 2023 and spread into two years, totaling \$619.4 million (Avg. \$310 million per year).

**Exhibit 10-11. 38 kV MiniGrid Transmission Investment,
\$ million**

	Priority 1	Priority 2	Priority 3	Priority 4	Priority 5
Technical Justification	2020-2022	2023-2024	2025-2026	2027	2028
Interconnection of Critical Loads	1678.5	413.1	212.8	75.3	33.1
Interconnection of Minigrids	24.7	20.9	9.7	0.0	13.6
Minigrid Backbone Extensions	38.9	49.0	18.9	28.5	0.0
Minigrid Main Backbone	28.7	0.0	6.9	0.0	0.0
Existing Infrastructure Hardening for Reliability -	49.9	136.4	64.3	101.3	42.4
Total	1820.6	619.4	312.6	205.1	89.2

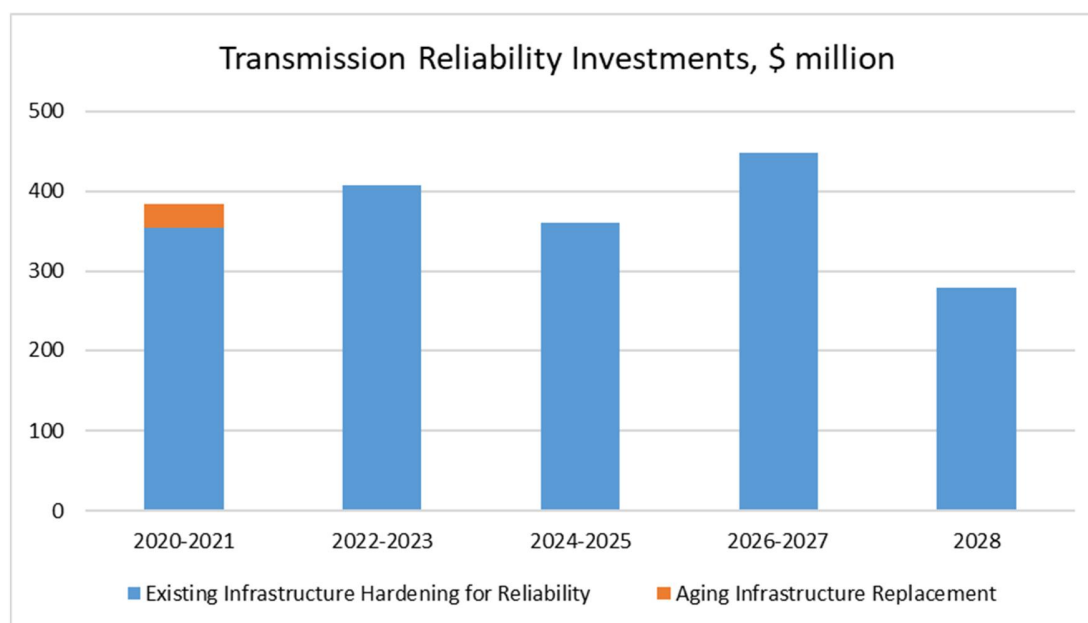
**Exhibit 10-12. 38 kV MiniGrid Transmission Investment,
\$ million**



Exhibits below show the schedule for the transmission reliability upgrades capital expenditures that are required for reliable of normal operation and not related to the MiniGrid. EPC work starts in 2020 for Priority 1 group project followed by Priority 2 group projects in 2023 and so on. Once again, we have spread the capital investment into two years for Priority 1 projects, totaling \$383.1 million (Avg. \$191.6 million per year). EPC work for Priority 2 group projects will start in 2022 and spread through two years, totaling \$408.1 million (Avg. \$ 204 million per year).

Exhibit 10-13 Transmission Reliability Investment, \$ million

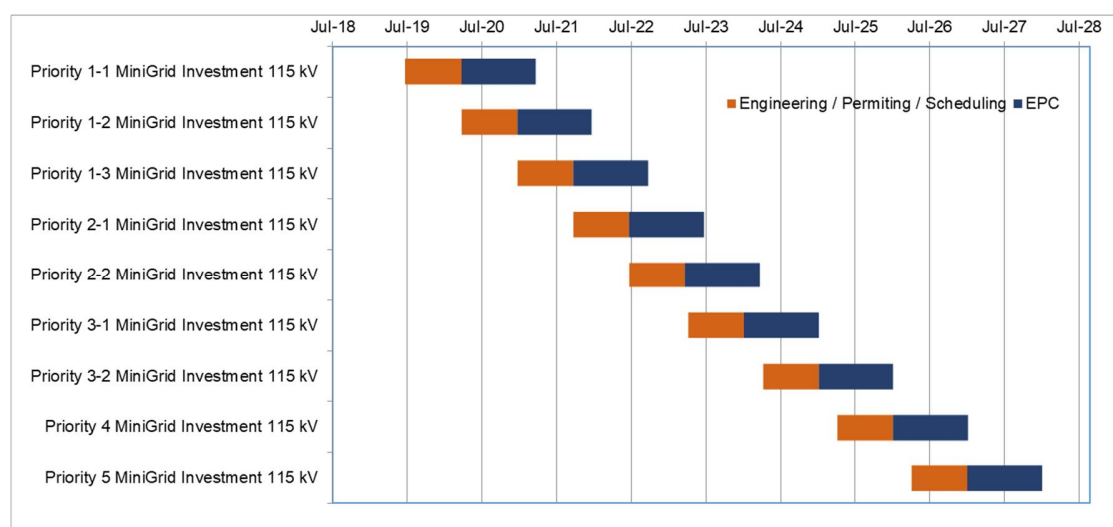
	Priority 1	Priority 2	Priority 3	Priority 4	Priority 5
Technical Justification	2020-2021	2022-2023	2024-2025	2026-2027	2028
Aging Infrastructure Replacement	28.8	0.0	0.0	0.0	0.0
Existing Infrastructure Hardening for Reliability	354.4	408.1	359.8	448.6	279.8
Total	383.1	408.1	359.8	448.6	279.8

Exhibit 10-14. Transmission Reliability Investment, \$ million

10.2.3 Timetables

The Exhibit below shows the timetables of 115 kV and above MiniGrid transmission investment implementation for both the engineering/permitting/outage scheduling phase and EPC phase.

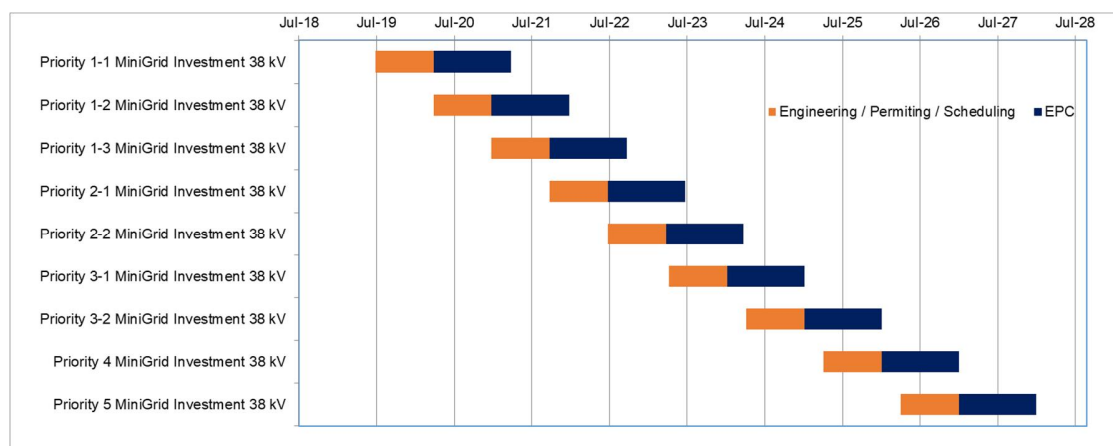
Priority 1 and 2 projects are estimated to be completed before 2024, and all projects are assumed to be in service by 2028.

Figure 10-15. 115 kV MiniGrid Transmission Investment timeline

The exhibit below shows the timetables of 38 kV transmission line and 115/38 kV substations MiniGrid transmission investment implementation for both the engineering/permitting/outage scheduling phase and EPC phase.

Similarly, Priority 1 and 2 projects are estimated to be completed before 2024, and all projects are assumed to be in-service by 2028.

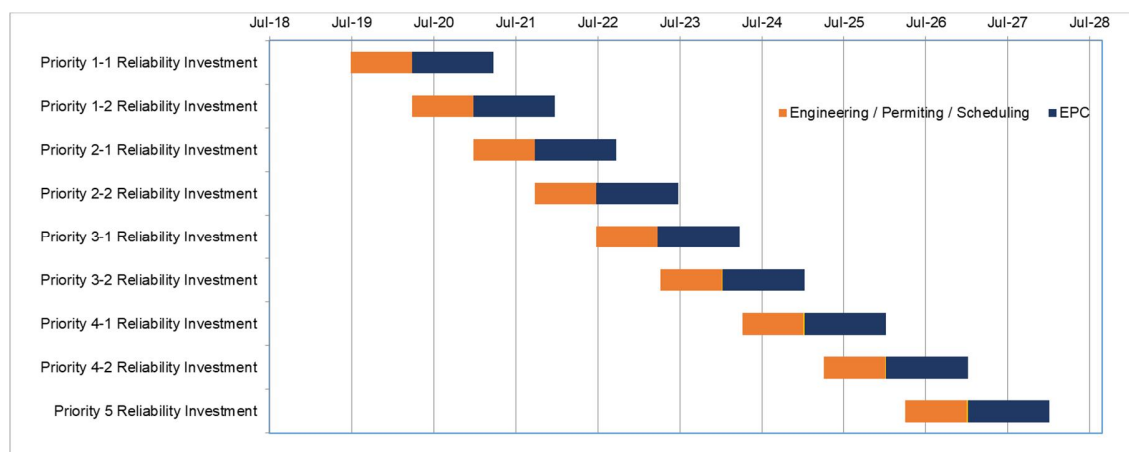
Exhibit 10-16. 38 kV MiniGrid Transmission Investment, timeline



The Exhibit below shows the timetables of transmission reliability upgrades not related to MiniGrid investment implementation for both the engineering/permitting/outage scheduling phase and EPC phase.

Priority 1 and 2 projects are estimated to be completed before 2023, and all projects are assumed to be in-service by 2028.

Exhibit 10-17. Transmission Reliability Investment, timeline



10.2.4 Permitting and Regulatory Activities

The action plan described above will require a host of additional approvals from the Puerto Rico and federal government authorities and agencies.

Permitting: The approval includes air, water and land use permits associated with the design, construction and operation of the transmission projects. Environmental Assessment (EA) or Environmental Impact Statement (EIS) reviewed by various Puerto Rico and federal agencies and Puerto Rico Office of Permits Management (OGPe) and construction permits.

Siting Approval: Most high-voltage transmission projects will require the state siting approval. Project sponsors will need to carry out environmental and detailed engineering work in order to establish a highly-detailed project plan to support the application.

Wetlands and Waterways: Any proposed project should be sited to avoid and minimize impacts to wetlands or other areas of environmental concerns. If the project cannot avoid such impact, it is expected to be subject to regulations certain additional permitting programs, namely Section 401 and Section 404 of the Clean Water Act, Section 10 of the Rivers and Harbors Act. Detailed analyses will be conducted for siting and routing for the specific permit.

Other Minor Permits: In addition to the above, some other minor permits may be required for any construction. These include permits related to airspace clearance, stormwater/erosion and sedimentation control, road crossings, and utility and railroad crossings.

While PREPA will need to support these applications and permits for all the projects listed, PREPA expects the project bidders will provide vast majority of the work and expenses associated with any required permitting activities.

10.3 Distribution System

The investments in the distribution system are designed to achieve the following objectives:

- a) Ensure resiliency of supply to the end customer at a level consistent with the improvements made at the generation and transmission levels for the formation of the MiniGrids and with initial focus on Critical and Priority Loads.
- b) Support the integration of distributed energy resources and, in particular, roof top solar.

To achieve these objectives Siemens, with the collaboration of PREPA, assessed the types of load (Critical, Priority or Balance) served by each of the feeders in PREPA's system and created a priority conversion index based on the criticality of the load served and the condition of the assets serving the load.

With the procedure above, we identified the air insulated substations that should be upgraded to GIS to ensure their survivability from a major hurricane and that were served by transmission substations that were either going to be upgraded, according to the investment plan discussed earlier, or already had an adequate level of reliability and needed no upgrade. Further, Siemens coordinated the timing of the upgrade at the transmission and distribution levels so that the projects would be done in parallel as much as possible. Finally, in the conversion to GIS, priority was given to those substations with voltages under 13.2 kV, as the system should be normalized to that voltage and there is a strong correlation of aging infrastructure, particularly those at the lowest primary distribution system voltage of 4.16 kV.

The CapEx for substations was estimated using PREPA's 3 main designs depending on load served, as shown in the exhibit below.

**Exhibit 10-18. PREPA's preferred substation designs
(MV – 13.2 kV)**

	MVA	Cost GIS	Transformer	Installation Labor+ Material+ Overhead + Testing & commissioning	Total
S/S 1	22.4	530,661	651,300	354,588	1,536,549
S/S 2	33.6	530,661	976,950	452,283	1,959,894
S/S 3	44.8	530,661	1,302,600	549,978	2,383,239

For the feeders we followed a similar procedure as for the substations, and in this case, we identified the feeders that, given the criticality of the load served, should have their mainlines (also called backbone or trunk-lines) rebuilt from overhead to underground cables. As before, priority was given to feeders with voltages under 13.2 kV and that were associated to substations that were going to be upgraded to GIS or already had adequate levels of reliability.

For the estimation of the investments, we considered maintaining the overall ampacity of the mainline using PREPA's standardized underground cables as shown in the exhibit below. No CapEx for voltage conversion to 13.2 kV was provided as this is highly dependent on the assets on site.

Exhibit 10-19. PREPA's Mainline Conductor Replacement

PREPA O/H Conductors	Ratings (amps)		Replacement	Ratings (amps)	
	Normal	Emergency		Normal	
1/0 AAAC	212	239	4/0 XLPE	305	
1/0 ACSR	221	243	4/0 XLPE	305	
2/0 ACSR	252	278	4/0 XLPE	305	
3/0 SPACER 15 KV	265	298	4/0 XLPE	305	
1/0 CU	269	303	4/0 XLPE	305	
3/0 AAAC	284	321	4/0 XLPE	305	
3/0 ACSR	289	318	4/0 XLPE	305	
2/0 CU	311	352	500 XLPE	485	
4/0 ACSR	328	361	500 XLPE	485	
3/0 CU	360	407	500 XLPE	485	
3/0 CU XLP 15 KV	360	407	500 XLPE	485	
266 ACSR SPACER	382	436	500 XLPE	485	
266 ACSR	418	466	500 XLPE	485	
250 CU	461	523	500 XLPE	485	
336 ACSR	483	540	500 XLPE	485	
336 SPACER	483	540	500 XLPE	485	
300 CU	500	550	750 XLPE	584	
556 SPACER	600	700	750 XLPE	584	
556 ACSR	650	700	750 XLPE	584	
652.4 AAAC	651	450	750 XLPE	584	
500 CU XLP 15 KV	709	808	750 XLPE	584	
795 ACSR	824	925	750 XLPE	584	

	Unit Costs \$2016			
	Conductor	Ducts	Total	Total \$ 2018
	US\$/Mile	US\$/Mile	US\$/Mile	US\$/Mile
4/0 XLPE	240,298	220,104	460,402	484,000
500 XLPE	366,699	276,673	643,372	676,000
750 XLPE	465,084	276,673	741,756	779,000

For the incorporation of photovoltaic (PV) systems, Siemens conducted a high level estimation of the possible impact of the projected rooftop PV growth in the next five years conservatively, assuming that it occurs in the feeders where there are already installations. This analysis identified those feeders where it is possible that there would be voltage regulation issues, localized overloads or the risk of reverse power flows to the transmission system.

For the screening of feeders where there could be a risk of voltage regulation issues (possibly requiring installation of voltage regulation equipment), we identified those feeders where either the aggregated rooftop generation was close to (90% threshold assumed) or exceeded the noon time load on the feeder, or where it represented more than 30% of the feeder capacity, as determined considering the nominal voltage and the conductor at the substation exit.

For the determination of those feeders where overload could be possible and should be investigated, we identified those feeders where, if the aggregated PV was located downstream of the smallest mainline conductor and lowest feeder voltage⁶⁸, there would be an overload and the mainline would need to be upgraded.

Finally, we identified those feeders where, during noon-time light load conditions, there would be a risk of reverse power flow, necessitating the upgrade of the protection equipment and settings and, under some situations, the addition of voltage regulation equipment.

With this approach, we identified a group of 4.16 kV feeders that are strong candidates to upgrade to 13.2 kV.

It is important to point out that the distribution analysis above can only be used for screening purposes and it is not a substitute for the necessary detailed system studies that must consider the feeder topology, assets in service, and location of the load and PV systems. This future detailed analysis, which is beyond the scope of this evaluation, must include an evaluation of the expected performance of equipment; refinement of the definition of the necessary improvements, capital expenditures, and timing to implement the projects.

⁶⁸ PREPA's Voltage Conversion Policy requires upgrading the distribution system primary voltage to 13.2 kV. As part of this voltage conversion process, PREPA has feeders that operate at multiple primary distribution voltages. For example, it has feeders with a source voltage of 13.2 kV that include step-down power transformers to supply loads at lower voltages (8.32 kV, 7.2 kV and 4.16 kV).

Similar to the transmission investments mentioned above, for distribution substation and feeder upgrades, a total of four (4) groups of priority, Priority 1 through Priority 4, have been selected considering the priority (timing) of the associated transmission projects and the intrinsic importance of the distribution investment for a reliable and resilient electricity supply of the critical and priority loads. As was the case in the transmission system evaluation, Priority 1 projects will be assumed to have the engineering/permitting/outage scheduling work start as early as July 2019, with engineering, procurement and construction (EPC) starting early 2020, and commercial in-service data as soon as March 2021. Projects in Priority 2 group will start upon completion of EPC work of all Priority 1 projects, with in-service date from 2023 to 2024. The above timeline is a high level estimation at this time and will be refined once the necessary distribution studies have been carried out. The action plan focuses mainly on the first 5 years for investment implementation, therefore, we provide below a list of Priority 1 and Priority 2 substations and feeders that were identified as targets for upgrade by our resiliency screening assessment. This screening does not include an evaluation of the actual assets of the distribution system, the particular operational limitations, nor a thorough on-site assessment. **Error! Reference source not found.** Exhibit B-7 in the confidential Attachment B, contains the substations identified for upgrade considering the three PREPA's standardized sizes and designs as presented earlier. Also, the first 19 substations in the list have already been identified by PREPA and FEMA for upgrade/relocation. The balance is sorted in order of importance (see Appendix 1 for details on the determination of the Priority of Conversion Index (PoCI)).

Exhibit B-8 in the confidential Attachment B, provides an overview of the feeders identified for undergrounding of the mainline based on the criticality of the load served and other aspects discussed above. See Appendix 1 for details on the sorting of the feeders.

Finally, 45 feeders were identified as potentially having issues with the interconnection of PV systems in the next 5 years, of which 30 (66%) have at least one section at 4.16 kV and it would highly benefit from upgrading to 13.2 kV. The exhibit below shows the total number of feeders identified as candidates for requiring upgrades for the integration of distributed generation (Appendix 1 provides additional details).

Exhibit 10-20. Number of Feeders with potential issues for integration of rooftop PV systems in the next 5 years

Min Nominal Voltage (1)	Voltage Issues Possible (2)	Overload Issues Possible (3)	Reverse Flow Possible (4)
4.16	21	10	23
7.2	1	1	0
8.32	4	1	4
13.2	9	1	8

- (1) If there are two voltages on a feeder this is the lowest voltage and it is used to determine the potential for overload (e.g. the DG is downstream of the step down transformer)
- (2) Voltage issues could happen if the PV is greater than 30% of the feeder capacity at the s/s exit (highest nominal voltage and largest conductor) or if greater than 90% of the light load
- (3) Calculated using the smallest conductor section at the mainline and lowest voltage (i.e. the DG is downstream)
- (4) If the DG is greater than 80% of the light load.

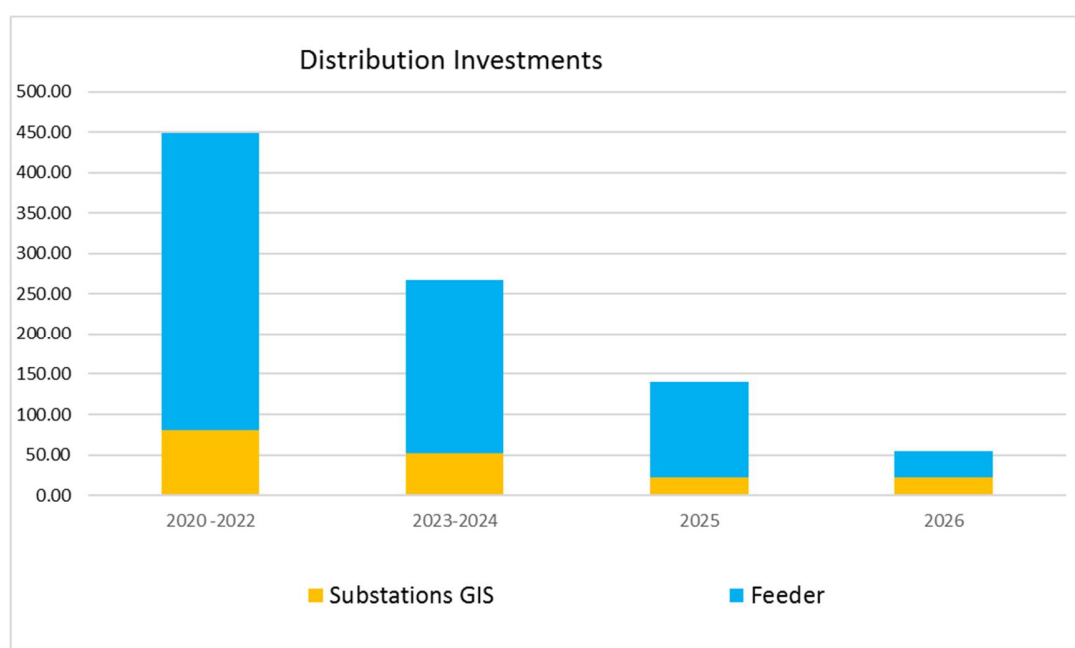
10.3.1 Schedule of Capital Expenditures

The exhibits below show the schedule for substation conversion to GIS and undergrounding of feeders for the next 10 years. EPC work starts in 2020 for Priority 1 group projects, followed by Priority 2 group projects in 2022, and so on. The timing is selected to match the transmission system investments.

Exhibit 10-21. Distribution Investments, 2018\$ million

	Priority 1	Priority 2	Priority 3	Priority 4	
	2020 -2022	2023-2024	2025	2026	Total
Substations GIS	81.17	52.40	21.94	21.67	177.17
Feeder	367.89	214.59	118.93	32.90	734.31
Total	449.06	266.99	140.86	54.57	911.48

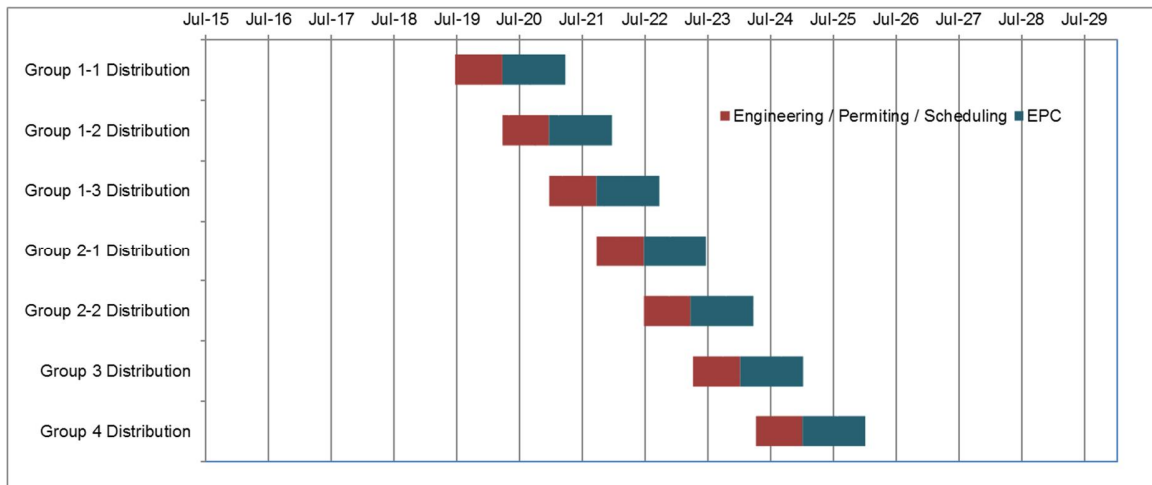
Exhibit 10-22. Distribution Investment, 2018\$ million



10.3.2 Timetables

The Exhibit below shows the timetables for the distribution investments (GIS substation conversion and feeders). It is noted that both Group 1 and 2 are expected to be completed by 2024, which is an aggressive timeline, but in line with the importance of these investments.

Exhibit 10-23. Distribution Investment timeline



10.3.3 Permitting and Regulatory Activities

The action plan described above will require a host of additional approvals from the Puerto Rico and federal government authorities and agencies. These are expected to be similar to those for transmission albeit of lesser scope and faster timelines. The main challenge for distribution will be the scheduling of multiple projects and the coordination with transmission.



Gas Pipeline Competition Model

Gas Pipeline Competition Model (GPCM®)

Siemens utilizes the Gas Pipeline Competition Model (GPCM®) to provide rigorous natural gas market evaluations. GPCM® is an industry-leading modeling tool that Siemens license and adapt to include the most up-to-date assumptions on supply, demand, and infrastructure. These assumptions are updated every quarter, with a full review of inputs in the spring and fall (coordinated with Siemens power market modeling work) and a short-term calibration every summer and winter. With GPCM® Siemens cover the entire interconnected North American natural gas market, including the evolving Mexican natural gas (and related power) market.

For inputs, Siemens utilize leading data sources such as DrillingInfo's ProdCast® tool for natural gas production forecasting. ProdCast® allows Siemens to input its oil and gas price assumptions into the model, providing an iterative calibration opportunity to better refine the supply outlook. On the demand side, Siemens develop its outlook from primary sources, including its own electricity market modeling for power sector natural gas demand. Finally, Siemens regularly monitor updates in pipeline infrastructure in-service dates, capacities, and regulatory requirements to ensure Siemens have the latest outlook for pipeline buildout in its modeling.

As an output from GPCM®, Siemens provide short-term and long-term price and basis forecasting for all major natural gas market and supply area liquid trading points in North America as well as economic pipeline flow analysis. Minor, illiquid, or retired natural gas trading points can also be modeled, upon request. Siemens National model outlook can be customized in the model in many different ways to test variables such as a pipeline cancellation, an unexpected growth or decline trend in production from a particular play, the impact of a new major LNG export facility, or any other number of Scenarios.

GPCM® Model Structure and Capabilities

Mathematically, GPCM® is a network model that can be diagrammed as a set of "nodes" and "arcs". Nodes represent production regions, pipeline zones, interconnects, storage facilities, delivery points, and customers or customer groups. The connections between these nodes are called arcs, which represent transactions and flows. Some of these are supplier deliveries to pipelines, transportation across zones and from one zone to another, transfers of gas by one pipeline to another, delivery of gas into storage, storage of gas from one period to another, withdrawal of gas from storage, and pipeline deliveries of gas to customers.

GPCM® dynamically solves for economic rents, allowing cheaper supplies to be used before more expensive supplies and enabling customers willing to pay more to be served before those willing to pay less. By including the entire system of North American gas production,

transmission, storage, consumption, and imports/exports, GPCM® optimizes gas flows in an economically sensible order to produce an economically efficient, market-clearing solution. GPCM® contains more than 200 existing and proposed pipelines, 400 storage areas, 85 production areas, 15 liquefied natural gas (LNG) import/export terminals, and nearly 500 demand centers.

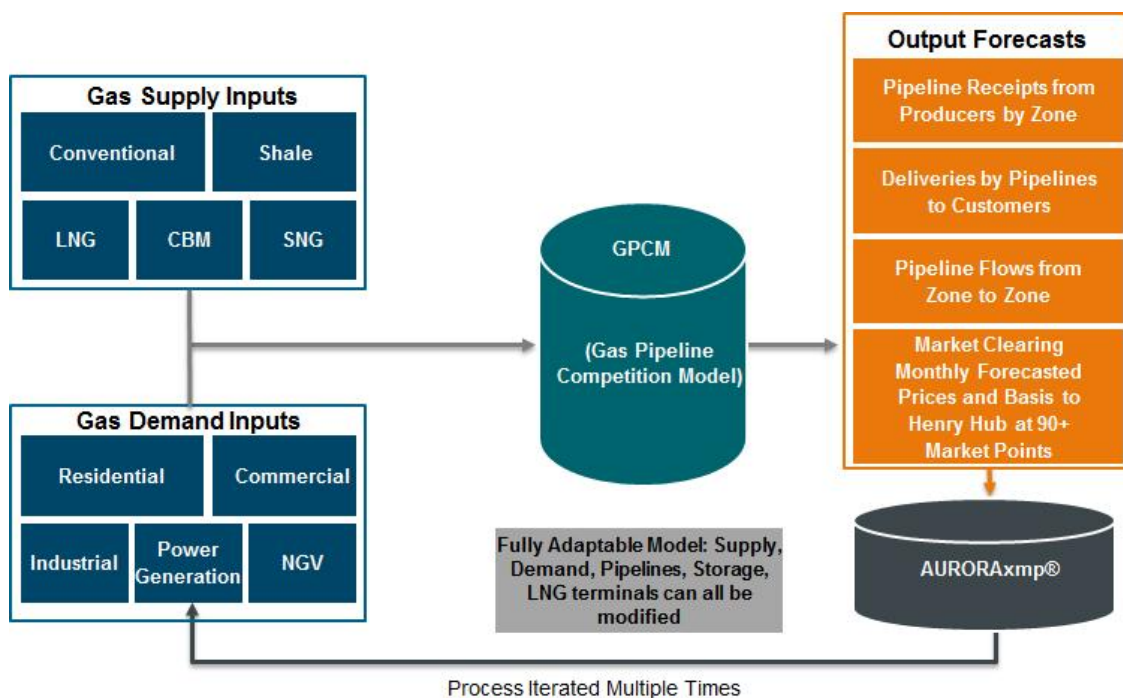
The output from GPCM® consists of the following types of items, which can be exported to an Excel spreadsheet for further analysis and reporting:

- Production and spot market prices by region
- Pipeline receipts from producers by zone
- Pipeline flows from zone to zone
- Transportation prices and discounting by pipeline and zone
- Transfers between pipelines at interconnects
- Injections into and withdrawals from storage
- Deliveries by pipelines to customers
- Gas supply available to each customer in each region
- Market clearing prices in each region

GPCM® Geography and Granularity

GPCM® covers the North American natural gas market, including the continental United States, Canada, and Mexico. GPCM® also contains a graphical display system to visually analyze interconnections, flows, and other output from the model. Demand forecasts can be manipulated by sector and by state. Supply sources can be manipulated by basin or play. Output data is provided on a monthly basis but can be aggregated up to annual averages. The forecasting horizon extends out to December 2040.

Figure A-1. GPCM® and Integration with Power Market Model (AURORAxmp®)



Source: Siemens

GPCM® Power-Gas Model Integration

The integration of the AURORAxmp® and GPCM® modeling frameworks is one of the cornerstones of Siemens’s modeling. At a high level, the GPCM® modeling framework receives inputs from AURORAxmp® on current and expected power sector gas demand based on expected generation capacity additions, coal-gas switching, coal plant retirements, impacts of carbon regime etc. The AURORAxmp® model in turn receives gas pricing inputs based on the supply economics, pipeline expansion plans, and all natural gas consuming sectors of the economy, including power. The final “equilibrated level” is such that gas price levels and the implied power sector gas demand levels are consistent across both models.

It is important to note that initially Siemens develops each of its fundamental market forecasts for natural gas (GPCM®) and power (AURORAxmp®) independently. Once complete, these independent forecasts are then harmonized through the iterative feedback process. Monthly natural gas prices at the benchmark Henry Hub and 60+ major liquid natural gas trading hubs throughout North America developed in GPCM® are used as inputs to the AURORAxmp® model. The output from the power model is then segmented into monthly state level data on natural gas consumption in the power sector. This forecast is then used as an input to the natural gas model, by setting demand targets for power sector gas consumption and by setting the price elasticity of power sector gas demand to zero. When a new set of gas prices and basis forecasts have been computed, a full iteration has been completed. For the second and third iterations, a weighted average of previous iterations is used to dampen oscillations between cycles (for example, a low gas price would encourage high gas burn, which would

raise prices, which would lower gas burn, and so forth). Typically, after 3-4 iterations, the models are sufficiently calibrated such that further iterations are not needed.

It should be noted that prior to the harmonization efforts between GPCM® and AURORAxmp®, the gas model undergoes its own balancing with the supply assumptions. DrillingInfo's ProdCast® tool for natural gas production forecasting allows Siemens to input its own crude oil and natural gas price assumptions into the model, providing an iterative calibration opportunity to better refine the natural gas supply outlook. Also, at the macro-economic level, both GPCM® and AURORAxmp® follow internally consistent assumptions around GNP growth rate and the electrical sector demand tied to the GNP growth rate. The GPCM® model also has separate growth rates for the other sectors of the economy.

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