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Integrated Resource Plan Volume I: Supply Portfolios and Futures Analysis

Draft for the Review of the Puerto Rico Energy Commission

Prepared for

Puerto Rico Electric Power Authority (PREPA)

Submitted by:
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Section

1

Executive Summary

In its 2015 Integrated Resource Plan (IRP), PREPA identifies its preferred strategy for satisfying its electric power requirements over the IRP planning horizon of fiscal year (FY) 2016 to 2035 (July 1, 2015 – June 30, 2035). The plan best meets PREPA's objective of providing for its long-term electricity needs in a reliable, flexible and cost effective manner under a variety of market, regulatory and economic conditions.

PREPA supplies the majority of the electricity consumed in Puerto Rico. PREPA's system includes generation plants, transmission and distribution systems. It owns and operates approximately 4,638 megawatts (MW) of fossil fuel fired generation and 60 MW[1] of hydroelectric generation. To supplement its own capacity, PREPA purchases power from two cogenerators under Power Purchase Operating Agreements (PPOAs) for a total capacity of 961 MW. In addition, PREPA contracts 173 MW from six existing renewable projects[2]. Also there are 60 MW installed distributed generation (DG) in the subtransmission (38 kV) and distribution (13.2 kV and below) systems.

PREPA's load has declined from its historical system peak of 3,685 MW in FY 2006 to 3,159 MW in FY 2014. The most recent peak observed on October 2, 2014 at the 21st hour was 3,030 MW.

PREPA continues to apply the Mercury and Air Toxics Standards (MATS) in the IRP, notwithstanding the recent United States Supreme Court decision, in Michigan v. EPA, U.S., No. 14-46, slip op. (June 29, 2015), in which the Court ruled that the United States Environmental Protection Agency (EPA) erred by failing to consider costs when deciding whether it was "appropriate and necessary" to regulate emissions of mercury and other hazardous air pollutants from power plants like those owned by PREPA. The Supreme Court, however, did not invalidate the MATS rule and as a result all power plants continue to be legally obligated to meet the MATS standards. The Supreme Court simply returned the MATS rule to the lower court for it to determine whether the rule should be simply remanded to EPA to correct the deficiencies outlined by the Supreme Court (a remand) or invalidate the rule completely (a vacatur). Because MATS remains in effect, PREPA will continue to work to modernize its power system and achieve permanent, consistent compliance with the Clean Air Act. Moreover, EPA has indicated that it intends to pull the MATS requirements in their current form into any future rule.

[1] The hydro power plant has a nameplate capacity of 100 MW.
[2] This includes the San Fermín 20 MW and Horizon 10 MW projects that are in pre-operation.

1.1 Context and Approach

PREPA is required under Puerto Rico Act 57 of 2014 (Act 57-2014) to prepare an IRP which comprehensively evaluates all existing and future generation resources to identify the most efficient plan to meet its electric power requirements over the study period, in consideration of reliability, stability and future renewable generation levels. PREPA's forbearance agreement with its creditors requires a business plan that will be in part based on the IRP.

PREPA's MATS compliance strategy regarding its existing steam units was a priority for the first five-year period during 2016 - 2020 for this study. In addition, PREPA is developing the Aguirre Offshore Gas Port (AOGP) project and gas pipeline to deliver natural gas to the Aguirre power complex by July 1, 2017.

The IRP analysis was designed to identify solutions to key challenges that PREPA will face over the planning horizon. The major questions addressed include the load profile, MATS compliance, renewable generation integration, and the preferred resource options for the future. Siemens performed the IRP covering key elements including transmission, load forecast, demand side management, distributed generation, energy efficiency, fuel forecast and infrastructure review, renewables, supply side resources, and production costs models.

Siemens team worked closely with PREPA management and its financial advisors in defining meaningful and plausible future scenarios and designing feasible supply portfolios. It is important to note that the assumptions reflect conditions as of June 30, 2015 including PREPA's financial situation. Siemens utilized PROMOD and PSS®E in modeling the PREPA system and production costs.

PROMOD IV is the industry-leading Fundamental Electric Market Simulation solution, incorporating extensive details in generating unit operating characteristics, transmission grid topology and constraints, and market system operations. PROMOD IV performs a security constrained unit commitment and economic dispatch that is optimized with operating reserve requirements, similar to how ISOs set schedules and determines prices. PROMOD is the tool that PREPA uses to analyze the expected operation of its generating fleet and purchased power.

PSS®E is a trusted leader in the power industry for cutting-edge electric transmission system analysis and planning. Used in over 115 countries worldwide, including Puerto Rico, PSS®E is leading the market in advances in electric transmission modeling and simulation. PSS®E has multiple modules and the most relevant for this study are: a) Power Flow and Contingency Analysis: fast and robust power flow solution for network models up to 200,000 buses, fast steady-state contingency analysis, including automatic corrective actions and remedial action scheme modeling, automated PV/QV analysis with plot generation, and b) the PSS®E Dynamic Simulation module is a versatile tool to investigate system response to disturbances that cause large and sudden changes in the power system. The dynamic simulation module employs a vast library of built-in models for modeling different types of equipment, and with capability to create user defined models of any complexity. An integrated dynamic simulation plotting package allows for quick generation of plotting with ability to export to several popular graphic formats.

The result of the IRP provides insight of generation resources that best meet PREPA's system needs. The detailed analyses of the IRP are presented in the following five volumes of the IRP report:

- Volume I: Supply Portfolios and Futures Analysis (including Fuel Infrastructure)
- Volume II: Transmission Study
- Volume III: Demand Forecast, Fuel Forecast and Demand Side Management
- Volume IV: Environmental Assessment
- Volume V: Evaluation of DG Impacts on the Distribution System

This Volume I report provides a description of the various resource portfolios analyzed under a range of market conditions and provides a recommendation on the best performing portfolio taking into account cost, reliability, and environmental considerations. ***All dollar amounts presented in Volume I of the IRP report are in real 2015 dollars***.

1.2 Futures and Supply Portfolios

Based on extensive discussions with PREPA regarding the load, generation, transmission, operation, environmental compliance, renewable portfolio standards (RPS), energy efficiency, distributed generation (DG), and current and future financial situation (capital availability), the Siemens team proposes four future scenarios (Futures), three Supply Portfolios, and evaluation metrics for the study period. Also a number of sensitivities were included in the study to evaluate the impact of deviations from the core portfolio and future combinations.

A Future is defined as a set of internally consistent assumptions that describe the future external environment in which PREPA might be expected to operate its Supply Portfolios. These elements include, but are not limited to, gas availability in the South and North, delivered fuel prices, capital availability constraints, load, RPS, DG penetration, energy efficiency, and other parameters that are outside of PREPA's control but will impact the dispatch and operation of PREPA's system.

- Future 1 is the base case with AOGP coming on line by July 1, 2017 and with limited access to capital.
- Future 2 is a pessimistic case assuming that AOGP does not happen.
- Future 3 is an optimistic case assuming that in addition to AOGP bringing gas to the South by July 1, 2017, gas will be available to the North by July 1, 2022. Future 3 also assumes improved access to capital allowing the acceleration of new builds and earlier achievement of efficiency gains.
- Future 4 is designed to evaluate a potential future state similar to Future 1, with the exception of doubling the impact of DG combined with slightly lower load forecast (reduced net load forecast).

A Supply Portfolio is the set of generation resources that PREPA can deploy to meet customer demand, environmental compliance, and system reliability requirements. The performance of each Supply Portfolio was evaluated based on a set of financial and non-financial metrics. The recommended Supply Portfolio is the one that performs the best in terms of the financial, reliability and environmental metrics across the Futures. Three Supply Portfolios were considered to evaluate the merits of focusing on repowering existing generation units, new builds with smaller combined cycle units, or new builds with larger combined cycle units in the existing plants.

- Supply Portfolio 1 focuses on minimizing investments by pursuing repowering initiatives and utilizing existing equipment to the extent possible.

- Supply Portfolio 2 builds smaller new units in the form of 1x1 combined cycles with the goal of designing a flexible generation system that can better follow the net load profile[3] and the renewable projects variability.
- Supply Portfolio 3 focuses on large combined cycle builds to serve net base load, with less total installed new units than Portfolio 2.

In the IRP work, each portfolio is tested across the Futures. To the extent possible, unique combinations of portfolios and scenarios must be avoided as it becomes difficult to objectively assess the performance of the Supply Portfolio in terms of costs and risks. The Supply Portfolios have been designed from a point of view of minimizing capital investments, maximizing fuel efficiency, or introducing more system flexibility. All Portfolios were required to result in a secure system.

1.3 Recommended Supply Portfolio

Given the myriad of considerations and tradeoffs to be evaluated from the perspectives of generation, system operation, capital costs, fuel and operation costs, and environmental compliance, Siemens believes that a systematic approach of evaluating three distinctively different Supply Portfolios will help to establish clarity for the planning approaches with quantifiable metrics to support the recommended Supply Portfolio. The recommended Supply Portfolio is the one that performs the best across all four Futures, and meets PREPA's objectives of providing for its long-term electricity needs in a reliable, cost competitive, and flexible manner under a wide variety of market, regulatory, and economic conditions.

Portfolio 3, the recommended Supply Portfolio, would introduce significant resources to PREPA's existing electricity portfolio over the study period. This is facilitated by the addition of renewable resources as well as new, efficient fossil fueled generation resources to replace aged and inflexible existing generation units to improve system efficiency and better integrate increasing renewable resources.

Key elements of the incremental changes to PREPA's current generation system in the recommended Supply Portfolio include:

- New fossil fuel-fired generation: One F Class combined cycle unit at Palo Seco to replace Palo Seco 3 or 4 (to be retired or designated to limited use in FY 2021)[4]; Two H Class combined cycle units[5] to replace Aguirre steam units 1&2; Two H Class combined cycle units to replace Costa Sur steam units 5&6.

- Renewable energy addition: A total capacity of 1,056 MW (43 projects) are included. This includes 6 existing renewable projects of approximately 173 MW capacity and 37 future renewable projects with a total capacity of 883 MW. Also included is the projected DG of 322 MW by the end of the study period. Details of the renewable energy can be found in Section 4 of the report.

[3] Net Load = Gross Load – Renewable Generation

[4] Limited use units cannot be dispatched with capacity factors greater than 8 percent averaged over two years and are assumed available only to confront Major Events, such as large disruptions to the transmission system produced by hurricanes.

[5] One of these two H Class combined cycle units is located at San Juan site in Future 2 and 3.

- Existing fleet to be declared limited use or retired: Costa Sur 3&4, Palo Seco 1&2, San Juan 7&8, San Juan 9&10, and Palo Seco 3&4. Aguirre steam units 1&2 and Costa Sur steam units 5&6 will be replaced based on a staged schedule. Detailed replacement schedules of Portfolio 3 can be found in Section 7.4 of the report.

This recommended supply portfolio would incur estimated capital costs ranging $4.67 billion to $5.72 billion in real 2015 dollars under all four Futures.[6] Portfolio 3 has lower capital costs than Portfolio 2, but much higher than Portfolio 1. Table 1-2 provides a summary of the capital costs for Portfolio 3 under all four Futures.

1.4 Recommended Supply Portfolio Performance

The Supply Portfolios are evaluated against several important criteria, including:

- **Cost metrics**, which include capital costs and present value of system costs. Capital costs associated with construction of new generation, fuel infrastructure, transmission upgrades and improvements are evaluated. In addition, the present value of system costs[7] assesses the fuel costs, operating costs, and amortized capital costs.

- **Environmental and compliance metrics**, which focus on system wide emission reduction, CO_2 emissions, MATS compliance status, and RPS and renewable penetration.

- **Operation metrics**, which are monitored to assess the reliability, efficiency, adequacy and security of the power system. For example, renewable curtailment assesses the portfolio's performance in accommodating renewable generation without excessive curtailment; renewable generation curtailment happens when due to technical requirements of the conventional generating fleet a portion of the renewable generation cannot be accepted in the system and the renewable plant must back down its production although sun irradiation or wind is available[8]. Loss of Load Hours (LOLH) and reserve margin provide indication of the ability of the generating fleet to meet the load.

Siemens evaluated the three Supply Portfolios against four Futures across a consistent set of metrics. Table 1-1 presents the set of cost, operations, and environmental metrics that Siemens considered to identify the best performing Supply Portfolio. In addition, we monitored some secondary metrics such as impacts on fuel costs, purchased power costs

[6] Capital costs include on-going general transmission and distribution capital costs for maintenance, upgrades and repairs for lines, meters, etc. Capital costs exclude on-going generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

[7] The system costs include amortized capital costs, cost of power plant demolition, fuel costs, variable and fixed generation operating costs, purchased power costs from AES and EcoEléctrica and Renewable purchased power costs. The system costs are not intended to capture all costs but only costs that have an impact on the portfolios on an incremental basis.

[8] Curtailment also can have a financial impact to PREPA as per the existing contractual conditions, because if energy production capability is available given the meteorological conditions and PREPA cannot take it, then it has to be paid at the contractual prices and on an estimate of the energy that could have been produced.

and O&M, which are commented in the Section 8.3 to Section 8.13 of the report for each Portfolio and Future combinations, with detailed model results presented in Appendix C.

Table 1-1: Evaluation Metrics of Supply Portfolios

Objectives	Metrics
Cost	Present value of system costs
	Capital costs
Environmental Compliance/ Stewardship	CO_2 emissions
	MATS compliance
	RPS penetration
Operations	System efficiency
	Renewable curtailment
	Loss of load hours (LOLH)
	Reserve margin

Note:

(1) Clean Power Plan thresholds require Puerto Rico to reduce power plant CO_2 emissions to a rate of 1,470 lb/MWh for 2020-2029 period (average) and 1,413 lb/MWh for 2030 and beyond.

(2) Any new power generation must comply with CAA Section 111(b) with maximum CO_2 rate at 1,000 lb/MWh.

(3) Reserve Margin = (Resources Available – Peak Load)/ Peak Load

Source: Siemens PTI, Pace Global

The recommended Supply Portfolio was not rated highest in every single objective category. Rather, it provided the best balance of all objectives over a wide range of market conditions. In the context of all the Supply Portfolios and Futures combinations evaluated in the IRP, the recommended Supply Portfolio is Portfolio 3, with the following overall ratings:

- Rated ***Favorable*** with regard to costs metrics. This includes the capital costs and the net present value of system costs over the study period. As shown in Table 1-2, Portfolio 3 has slightly lower capital costs than Portfolio 2, but higher than Portfolio 1. As shown in Table 1-3, Portfolio 3 has the lowest system costs among the three portfolios.

- Rated ***Favorable*** with regard to environmental metrics. Portfolio 3 meets the Clean Power Plan thresholds for system wide CO_2 emissions and unit level CO_2 threshold for the H Class combined cycle units. In addition, Portfolio 3 meets a reduced RPS goal of 15 percent renewable energy by 2035. Portfolio 3 achieves the highest emission reduction for NOx, SOx, CO_2 and filterable particulate matter (FPM) as shown in Table 1-5.

- Rated ***Neutral to Favorable*** with regard to operation metrics. Table 1-4 summarizes the curtailment and LOLH for all three portfolios. Figure 1-1 summarizes the reserve margins (with and without the GTs and Cambalache units) for all three portfolios.

Table 1-2: Supply Portfolios Capital Costs Summary

Capital Costs	Unit	Portfolio 1		Portfolio 2				Portfolio 3			
		P1F1	P1F3	P2F1	P2F2	P2F3	P2F4	P3F1	P3F2	P3F3	P3F4
Generation	*$ million*	1,705	1,700	3,171	2,953	3,125	3,171	2,887	2,693	2,850	2,887
Fuel Infrastructure	*$ million*	385	886	385	0	886	385	385	0	886	385
Transmission	*$ million*	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981
Total	*$ million*	4,071	4,566	5,536	4,933	5,992	5,536	5,252	4,674	5,716	5,252

Source: Siemens PTI, Pace Global

Table 1-3: Supply Portfolios System Costs Summary

System Costs	Unit	P1F1	P1F1A	P1F3	P1F1 RAG
Total Present Value of System Costs	*$ million*	27,253	27,279	26,761	27,137
Average Annual System Costs	*$ million*	2,473	2,477	2,418	2,464

System Costs	Unit	P2F1	P2F2	P2F3	P2F4	P2F1Re	P2F1RAG
Total Present Value of System Costs	*$ million*	26,930	30,016	26,871	26,757	26,966	26,928
Average Annual System Costs	*$ million*	2,428	2,767	2,421	2,411	2,431	2,428

System Costs	Unit	P3F1	P3F2	P3F3	P3F4
Total Present Value of System Costs	*$ million*	26,842	29,301	26,660	26,648
Average Annual System Costs	*$ million*	2,415	2,663	2,394	2,397

Note:

(1) P1F1A, P1F1 RAG, P2F1RAG, and P2F1Re are additional portfolios sensitivities to determine the optimal technology for Palo Seco new generation and/or to test sensitivity to reduction on the new generation added at Aguirre, based on results of the core portfolios.

(2) Details of these additional sensitivities are discussed in Section 8.2.1 (P1F1A,P1F1RAG) and 8.2.2 (P2F1Re and P2F1RAG).

Source: Siemens PTI, Pace Global

Table 1-4: Supply Portfolios Curtailment, LOLH and Efficiency Summary

Operation Metrics	Unit	Portfolio 1		Portfolio 2				Portfolio 3			
		P1F1	P1F3	P2F1	P2F2	P2F3	P2F4	P3F1	P3F2	P3F3	P3F4
Max LOLH	Hours	9	10	7	0	6	9	4	4	6	15
Total Hours with Dump Energy > 283 MW	Hours	3	0	0	0	0	2	0	0	0	1
Average Annual Renewable Curtailment Cost	$ million	11	22	9	2	8	14	13	3	10	17
Average Annual Renewable Curtailment Percentage	%	3%	6%	3%	1%	3%	4%	4%	1%	3%	5%
System Heat Rate Improvement 2035 vs. 2016 (Total Generation)	%	16%	17%	25%	25%	25%	27%	26%	28%	26%	28%
System Heat Rate Improvement 2035 vs. 2016 (Thermal Generation)	%	5%	6%	14%	15%	14%	14%	15%	17%	15%	15%

Note:

(1) Loss of Load Hours (LOLH) is identified in PROMOD by using “Emergency Energy” to supply the load.

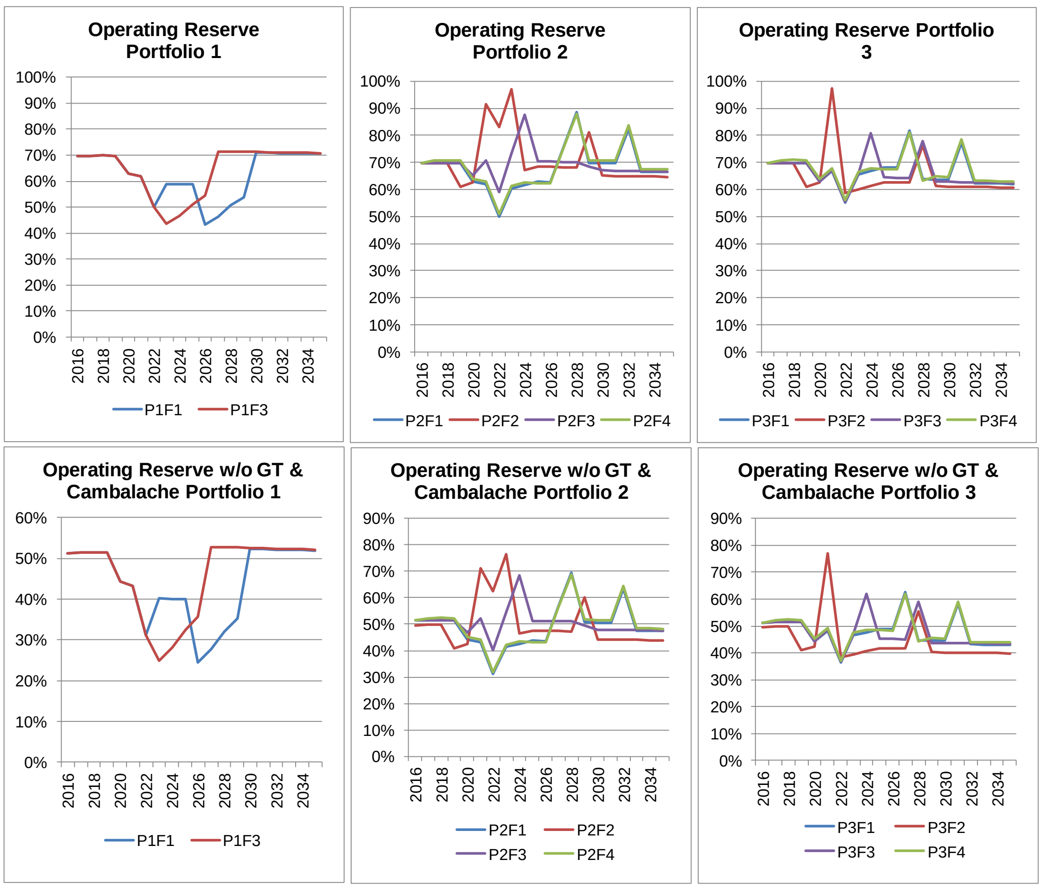
(2) The PROMOD runs did not consider the possibility of the redeployment of the 4x50 MW GTs currently at the Aguirre CC 1&2 that will become surplus after the repowering and that could remain in place for emergency service and did not consider the possibility of Cambalache 1 (83 MW) coming back to service. This total generation (283 MW) would be enough to eliminate most on the LOLH as shown in the table.

Source: Siemens PTI, Pace Global

Table 1-5: Average Annual Emission and Reduction (2035 vs. 2016)

Emission Metrics	Unit	Portfolio 1		Portfolio 2				Portfolio 3			
		P1F1	P1F3	P2F1	P2F2	P2F3	P2F4	P3F1	P3F2	P3F3	P3F4
Average Annual CO_2 Emission	million lbs.	23,487	23,105	22,738	23,706	22,154	22,439	22,603	23,469	21,342	22,316
CO_2 Emission Reduction (2035 vs. 2016)	%	26%	27%	35%	30%	36%	37%	36%	33%	41%	37%
Average Annual FPM Emission	million lbs.	25	24	25	27	25	25	25	27	25	25
FPM Emission Reduction (2035 vs. 2016)	%	16%	19%	10%	6%	12%	12%	12%	11%	15%	14%
Average Annual NO_x Emission	million lbs.	49	44	42	39	40	42	41	37	41	41
NO_x Emission Reduction (2035 vs. 2016)	%	24%	43%	62%	61%	55%	63%	63%	59%	46%	64%
Average Annual SO_x Emission	million lbs.	20	19	19	28	19	20	19	26	19	19
SO_x Emission Reduction Rate (2035 vs. 2016)	%	71%	78%	76%	76%	77%	77%	76%	75%	77%	76%

Figure 1-1: Supply Portfolios Reserve Margin Summary



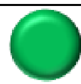
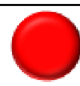
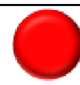
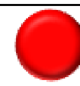
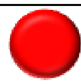
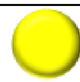
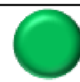
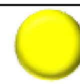
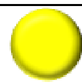
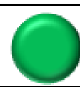
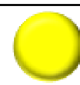
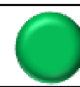
Note:

(1) Reserve Margin = (Resources Available – Peak load)/ Peak Load
(2) The available resources exclude units that are designated limited use.
(3) The first set of charts show the reserve margin based on the total resources available including the GTs (18x21 MW relatively old and inefficient combustion turbines) and Cambalache units.
(4) The second set of charts show the reserve margin based on the total resources available excluding the GTs and Cambalache units.
(5) The "one year" jump in reserve observed is due to the fact that in the portfolio implementation we don't retire the MATS compliant replaced units (Aguirre 1&2 and Costa Sur 5&6) until all units that will replace them (two or more new CC) are commissioned. This allows for some "shakedown" of the new generation.

Source: Siemens PTI, Pace Global

In conclusion, the recommended Supply Portfolio, Portfolio 3, would best support PREPA's overall strategy and allow it to pursue the appropriate combined cycle option, contingent upon permitting, siting and equipment manufacturer considerations and limitations. Table 1-6 illustrates assessment of all three Supply Portfolios under Future 1 in terms of capital costs, system costs, curtailment, and emission reduction. Sensitivity analysis presented in Section 9 assesses three sensitivities of the recommended Portfolio 3 under all Futures, including: a full RPS compliance, renewable freeze at current contract levels, and no AES contract renewal.

Table 1-6: Portfolios Results under Future 1

	Capital Costs	System Costs	Curtailment	Emission Reduction
Portfolio 1				
Portfolio 2				
Portfolio 3				

Note: Green light indicates favorable results; yellow light indicates neutral results and red light indicates unfavorable results.

Source: Pace Global

Section

2

Conclusions and Recommendations

Based on the results presented in this report it can be concluded the following:

1. While Portfolio 1 has the lowest capital cost, it is not able to achieve the required levels of renewable penetration. This portfolio also has the highest present value of system cost in Future 1 when compared with the other portfolios. It has adequate performance from an operational and environmental point of view, provided that the dispatch of the repowered Aguirre CC 1&2 are adjusted for compliance with the greenhouse gas (GHG) New Source Standard. This portfolio should only be considered in case of extreme capital limitations.

2. Portfolio 2 has the highest capital costs and while it has smaller units that add flexibility, it has a higher present value of system costs across all Futures when compared with Portfolio 3. The portfolio has acceptable operational performance, but would have problems meeting the GHG New Source Standard for the Palo Seco combined cycle units unless the dispatch of these units is forced to a higher value and the number of starts reduced[9], which will result in further deviation from the optimal dispatch. This is also the situation with the repowered Aguirre combined cycle, but to a much lesser degree.

3. Portfolio 3 has lower capital costs than Portfolio 2 and the lowest present value of system costs across all Futures. The portfolio has acceptable operational performance and with an adjustment to the dispatch of the repowered Aguirre combined cycle would be in compliance with the GHG New Source Standard. This is the recommended portfolio.

4. No portfolio is able to fully handle 20 percent renewable PPOA penetration in all Futures as the curtailment is above the 2 percent limit in certain years and certain Futures.

5. A renewable freeze would result in important savings under all Futures and Portfolios.

6. The non-renewal of AES contract can be handled by Portfolio 3 under all Futures. However, while in Future 1, 2 and 4 the system costs would be higher if the contract was not extended in 2027, under Future 3 there are small savings. This is due to the fact that gas is available in the North limiting the increase in fuel costs which is more than compensated by the elimination of capacity payments to AES.

[9] Every start results in additional fuel consumption; thus an increase in starts results in a corresponding increase in emissions per MWh. However reducing the number of starts for compliance adds some inflexibility that makes it more difficult to integrate the renewable generation.

Section

3

Thermal Supply Side Resources

Siemens reviewed PREPA's existing generation resources and new thermal and renewable generation resources to be considered in the IRP. The thermal supply side resources section includes a review of the capital and operating costs as well as the operating characteristics.

This section discussed only thermal generation resources; renewable generation resources are discussed in Section 4.

3.1 Existing PREPA Generation Resources

Siemens relied upon PREPA for existing unit generation characteristics as shown in Table 3-1. PREPA has 14 steam electric units with a total capacity of 2,892 MW located at four sites including Aguirre, Costa Sur, Palo Seco and San Juan. These steam units are subject to MATS compliance requirements. Unit-specific MATS compliance strategies and assumptions are discussed in Section 7 of the report, and in greater details in Volume IV of the IRP report. PREPA's four combined cycle (CC) units (Aguirre 1&2 CC and San Juan 5&6 CC)[10] with a total capacity of 920 MW[11] currently run on diesel. The 25 gas turbine (GT) units (Cambalache 1-3, Mayagüez 1-4 and distributed gas turbine fleet) with a total capacity of 826 MW currently run on diesel and are assumed to continue operation in all Portfolios and Futures. However, the Mayagüez units are four aero-derivative 50 MW[12] gas turbines with relatively good efficiency and are expected to continue providing service for the foreseeable future. The balances are 18 relatively old and inefficient 21 MW gas turbines to be relegated only to emergency service and the Cambalache units that have had reliability and efficiency issues.

To supplement its own capacity, PREPA purchases power from two co-generators under the terms and conditions of PPOAs, including 507 MW of gas-fired capacity from EcoEléctrica, L.P. and 454 MW of coal-fired capacity from AES. The 961 MW of capacity provided by the

[10] Aguirre CC units are very old (1975 -1976 initial operation) and extremely inefficient and current dispatch is very low. An upgrade to modern Gas Turbine (GT) technology is considered in the proposed generation portfolios, the nominal capacity of these units is 296 MW each, but this is limited to 260 MW in this study. San Juan 5&6 units are relatively modern F Class CCs and can continue as important generation resources in the north, its nominal capacity is 220 MW each but this was limited to 200 MW in this study. These units are also referred as the San Juan Repowering 1&2 or San Juan CC 1&2. They are a repowering of the San Juan Steam units 5&6.

[11] Based on maximum limits in this study of 260 MW x 2 + 200 MW x 2

[12] The nominal value is 55 MW and 50 MW is the maximum considered in this study.

co-generators brings the total capacity available to PREPA to 5,659 MW[13]. Table 3-1 presents basic parameters including rated capacity, fuel type, heat rate, fixed operating and maintenance (FOM) costs and variable operating and maintenance (VOM) costs of the existing generation resources. More detailed unit level modeling inputs are presented in the Appendix B.

[13] This value corresponds to the sum of the maximum capacities considered in this study. The total nominal capacity is 5,839 MW.

Table 3-1: Existing PREPA Generation Resources (see notes below)

	Generation Units	Capacity (MW)	Fuel	Heat Rate (btu/kWh)	FOM ($2015/kW-year)	VOM ($2015/MWh)
MATS Affected Units	Aguirre 1 ST	450	No. 6 fuel oil	9,600	30.57	2.15
	Aguirre 2 ST	450	No. 6 fuel oil	9,700	30.57	2.15
	Costa Sur 3 ST	85	No. 6 fuel oil	10,480	8.45	3.60
	Costa Sur 4 ST	85	No. 6 fuel oil	10,480	8.45	3.60
	Costa Sur 5 ST	410	Natural gas No. 6 fuel oil	9,750	34.31	2.60
	Costa Sur 6 ST	410	Natural gas No. 6 fuel oil	9,970	34.31	2.60
	Palo Seco 1 ST	85	No. 6 fuel oil	10,200	45.94	5.30
	Palo Seco 2 ST	85	No. 6 fuel oil	10,200	45.94	5.30
	Palo Seco 3 ST	216	No. 6 fuel oil	9,730	44.34	4.72
	Palo Seco 4 ST	216	No. 6 fuel oil	9,730	44.34	4.72
	San Juan 7 ST	100	No. 6 fuel oil	10,470	46.78	2.80
	San Juan 8 ST	100	No. 6 fuel oil	10,470	46.78	2.80
	San Juan 9 ST	100	No. 6 fuel oil	10,280	46.78	2.69
	San Juan 10 ST	100	No. 6 fuel oil	10,260	46.78	2.69
Combined Cycle, Gas Turbine and Hydro Units	Aguirre 1 CC	260	Diesel	11,140	21.60	6.48
	Aguirre 2 CC	260	Diesel	11,140	21.60	6.48
	San Juan 5 CC	200	Diesel	7,630	26.15	2.12
	San Juan 6 CC	200	Diesel	7,850	26.15	2.12
	Cambalache 1 GT	83	Diesel	11,550	23.32	5.27
	Cambalache 2 GT	83	Diesel	11,550	23.32	5.27
	Cambalache 3 GT	83	Diesel	11,550	23.32	5.27
	Mayaguez 1 GT	50	Diesel	9,320	10.15	6.11
	Mayaguez 2 GT	50	Diesel	9,320	10.15	6.11
	Mayaguez 3 GT	50	Diesel	9,320	10.15	6.11
	Mayaguez 4 GT	50	Diesel	9,320	10.15	6.11
	Gas Turbines	378	Diesel	14,400	25.33	19.27
	Hydro	60	Water	N/A	27.54	0.00
IPP units	AES Coal Plant	454	Coal	9,790	75.97	6.91
	EcoEléctrica Plant	507	Natural Gas	7,500	180.68	0.00
Total		**5,659**				

Note:

(1) The maximum capacities considered in the PROMOD models are based on information provided by PREPA. These capacities are smaller than the nominal capacities in the case of the San Juan 5&6 CC (nominal capacity of 220 MW each), Aguirre CC 1&2 (nominal capacity of 296 MW each), the Mayagüez GT (nominal capacity of 55 MW each) and the hydro generation (nominal capacity of 100 MW). The total nominal capacity of existing PREPA generation resources is 5,839 MW.

(2) Costa Sur 5&6 ST units burn natural gas and No. 6 fuel oil in a dual fuel firing scenario. Costa Sur 5 burns 80 percent of natural gas and 20 percent of No. 6 fuel oil and Costa Sur 6 burns 75 percent of natural gas and 25 percent of No. 6 fuel oil. These two units are currently in MATS compliance.

(3) Costa Sur 3&4, Palo Seco 1&2 and San Juan 7&8 are designated as limited use during FY 2015-2019 for a heat input capacity factor of less than 8 percent evaluated over two years. These six units may be retired by December 31, 2020.

(4) Palo Seco 3&4 will be either retired or designated as limited use after the new generation units at Palo Seco come on line.

Source: PREPA, Siemens PTI, Pace Global

3.2 Future Thermal Generation Resources

Siemens and PREPA discussed extensively the key criteria in developing new generation resources to allow for system flexibility and reliability, including the capability to accommodate a large block of renewable capacity, primarily solar. Solar integration is limited at present because the current base-load steam electric units cannot shut down and restart on a daily basis, have a minimum stable load of about 40 percent, and must be available for the evening peak when solar generation is not present. Based on the agreed system planning criteria, Siemens screened multiple generation resources candidates to form three Supply Portfolios. Supply Portfolio 1 focuses on repowering options, utilizing existing equipment to the extent possible. Supply Portfolio 2 focuses on smaller new units in the form of 1X1 CC[14]. Supply Portfolio 3 focuses on larger and more efficient 1x1 CC new units. In the process, Siemens relied upon information exchanged with PREPA, performance and cost information provided by vendors, and GT Pro[15] performance and cost calculations.

A more detailed discussion of the generation options considered in the screening and the rationale for selecting the units incorporated in the three Portfolios is provided in Section 3.2.4 and 3.2.5 of this report.

3.2.1 Representative Future Generation Resources and Fuels

All selected generation resources based on the above-mentioned screening process are analyzed based on dual fuel capability with natural gas and diesel, and the reciprocating engines will burn Light Fuel Oil or natural gas. These units could potentially burn Heavy Fuel Oil (referred to as HFO, No. 6 fuel oil or Bunker C) but there is no certainty that this use could be permitted. For dual fuel units, the unit output and heat rate are somewhat different depending on the fuel type. The selected representative options are summarized in Table 3-2, with detailed screening methodology discussed thereafter.

At present, only EcoEléctrica and Costa Sur have natural gas available. Other sites use HFO and light fuel oil (LFO), for which diesel usually is supplied. The IRP considered the Futures in which natural gas becomes available at Aguirre and/or in the North, near San Juan. In Futures where natural gas is available, certain existing units are converted from liquid fuel to natural gas or dual fuel, as follows:

- For natural gas at Aguirre, Aguirre 1&2 steam electric units currently burn HFO and will be converted to natural gas to comply with MATS. Aguirre CC 1&2 currently burn distillate and will be converted to dual fuel with natural gas as primary fuel and distillate as backup.
- For natural gas at San Juan, San Juan CC 5&6 will be converted to dual fuel with natural gas as primary and distillate as backup.

[14] 1x1 CC refers to one Gas Turbine/Heat Recovery Steam Generator (GT/HRSG) train matched to a single Steam Turbine Generator (STG). 2x1 or 3x1 refers to 2 or 3 GT/HRSG trains supplying one STG. Considerations for choosing from among these possible configurations are discussed later in this report.

[15] GT Pro is a software program licensed by Thermoflow for sizing and designing simple cycle, combined cycle, cogeneration 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.

Table 3-2: Representative Options in the Supply Portfolios

Repower & New CC Configurations	Fuel	Unit Capacity (MW per unit)	Heat Rate (Btu/kWh HHV)
Aguirre CC 1 & 2 Gas Turbine Replacement/Repower	Natural Gas	263	7,582
	Diesel	255	7,368
Aguirre 1 & 2 HFCC Repower	Diesel or Natural Gas	543	9,200
Costa Sur 5 & 6 HFCC Repower	Natural Gas	503	9,200
Siemens SCC-800 (Duct Fired)	Natural Gas	72	8,031
	Diesel	70	7,764
F Class CC (GE S107F.05) (Duct Fired)	Natural Gas	369	7,310
	Diesel	359	7,065
H Class CC (Siemens SCC6-8000H) (Duct Fired)	Natural Gas	393	6,979
Generic H Class (Duct Fired)	Diesel	381	6,770
Reciprocating Engines	Diesel	17	7,580
GE LM6000PG SPRINT SC	Diesel	48	9,785

Note: All units' performance rated at 85° F, 70 percent relative humidity and adjusted for expected average output and heat rate degradation.
Source: Pace Global

3.2.2 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 plant design 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, contingency and fees are added to determine an Engineering, Procurement and Construction (EPC) price. Certain owner's costs for development, permitting and legal/contracting activities are included. Siemens separately calculated financing cost of 2 percent and Interest during Construction (IDC) based on the EPC duration, drawdown schedule, and cost of debt of 6.86 percent. The financing cost and IDC are then added to the PEACE estimates to get all-in capital costs.

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, which is presented in Appendix B. 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 getting equipment and construction costs estimates from suppliers and contractors, but are suitable for planning purpose and provide a consistent approach across all generation resource options. The estimates also reflect the specific configuration and sizing of options, such as duct firing and Air Cooled Condensers, which can be difficult when factoring costs based on other projects whose configurations may vary. Table 3-3 summarizes the capital costs for the representative future generation resources.

Table 3-3: Repower and New Generation Capital Costs

Repower & New Generation Configurations	Capital Costs ($2015/KW)
Aguirre CC 1 & 2 Gas Turbine Replacement/Repower	703
Aguirre 1 & 2 HFCC Repower	320
Costa Sur 5 & 6 HFCC Repower	320
Siemens SCC-800 (Duct Fired)	1,648
F Class CC (GE S107F.05) (Duct Fired)	1,001
H Class CC (Siemens SCC6-8000H) (Duct Fired)	1,011
Reciprocating Engines	1,304
GE LM6000PG SPRINT SC	1,315

Note: Above calculation is based on natural gas fired capacity.
Source: Pace Global

Siemens further applied a projected capital costs curve to the above baseline capital costs. Capital costs are assumed to modestly increase over time based on the fact we are currently near the low end of the commodity cycle and our experience that technology improvements over time offer a more advanced technology while keeping costs the same[16]. Table 3-4 presents the capital cost escalation rate.

[16] This is a slight departure from conventional wisdom of showing a declining cost curve.

Table 3-4: Capital Costs Escalation Rate

Year	Capital Cost Escalation Rate
2015	1.00
2016	1.01
2017	1.02
2018	1.03
2019	1.04
2020	1.05
2021	1.06
2022	1.07
2023	1.08
2024	1.09
2025	1.10
2026	1.12
2027	1.13
2028	1.14
2029	1.15
2030	1.16
2031	1.17
2032	1.19
2033	1.20
2034	1.21
2035	1.22

Note: The capital cost escalation rates are expressed as a multiple of the 2015 level.
Source: Pace Global

3.2.3 Representative Future Generation Resources Characteristics

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.

A three-step process was used to determine generating unit characteristics and select technologies for portfolios:

1. Screening of available simple cycle gas turbines and combined cycle units based on published data at standard conditions on natural gas.
2. Analysis of selected configurations at site-specific conditions on gas and distillate fuels.
3. Selection of technologies to develop generation portfolios for analysis in PROMOD.

Siemens first performed a technology screening based mainly on published performance of available simple cycle and combined cycle generating units at ISO conditions (59° F, 60 percent relative humidity, and sea level) with wet cooling towers on natural gas fuel. A large reciprocating engine generator also was considered.

From this group, certain configurations were selected for modeling in GT Pro, as described in later sections below, to obtain performance specific to PREPA site conditions (85° F, 70 percent relative humidity, and 10 feet above mean sea level) on natural gas and distillate oil, with and without duct firing, and with dry or wet cooling as appropriate for the application. New CCs assumed dry cooling with Air Cooled Condensers (ACCs) and repowered configurations assumed wet cooling towers because existing steam turbines already use wet cooling (towers or once-through).

The GT Pro performance estimates were used to select which configurations to incorporate in the three Supply Portfolios. Table 3-5, Table 3-6 and Table 3-7 present the operational parameters of the SCC-800, GE S107F, SCC6-8000H[17] combined cycle units selected for the portfolios. Table 3-8 and Table 3-9 present the operational parameters of the reciprocating engine and GE LM6000 PG Sprint SC units tested in comparison with the SCC-800 unit at Palo Seco.

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

Also, it was not practical to analyze several different generating unit options for the small combined cycle over all the portfolios and futures in all years covered by the IRP analysis. So the SCC-800 (located at Palo Seco site) was selected for PROMOD runs and Siemens incorporated sensitivity analysis over a limited period to determine how other generation options would compare. Such options include large reciprocating engine generators as well as intercooled or standard aeroderivative GT peaking units.

Table 3-5: SCC-800 Operational Assumptions

Generation Unit Type	Unit	Siemens SCC-800	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	59	57
Max. Unit Capacity with Duct Fire	MW	72	70
Min. Unit Capacity	MW	24	23
Fixed O&M Expense	2015 $/kW-year	23.00	23.00
Variable O&M Expense	2015 $/MWh	3.00	3.00
Capital Costs	2015 $/kW	1,648	1,800
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	7.7	7.47
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	8.03	7.76
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	14	14
Ramp Down Rate	MW/minute	14	14
Regulation Minimum Range	MW	24	23
Regulation Maximum Range	MW	72	70
Regulation Ramp Rate	MW/minute	14	14

Source: Pace Global

[17] See Section 3.2.9 for discussions of generic H Class performance.

Table 3-6: GE S107F Operational Assumptions

Generation Unit Type	Unit	GE S107F	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	287	279
Max. Unit Capacity with Duct Fire	MW	369	359
Min. Unit Capacity	MW	115	112
Fixed O&M Expense	2015 $/kW-year	16.57	16.57
Variable O&M Expense	2015 $/MWh	4.77	4.77
Capital Costs	2015 $/kW	1,001	1,030
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	7.21	7.00
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	7.31	7.06
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	45	45
Ramp Down Rate	MW/minute	45	45
Regulation Minimum Range	MW	115	112
Regulation Maximum Range	MW	287	279
Regulation Ramp Rate	MW/minute	45	40

Source: Pace Global

Table 3-7: SCC6-8000H (Gas) and Generic H Class (Oil) Operational Assumptions

Generation Unit Type	Unit	Siemens SCC6-8000H	Generic H Class
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	368	357
Max. Unit Capacity with Duct Fire	MW	393	381
Min. Unit Capacity	MW	184	178
Fixed O&M Expense	2015 $/kW-year	16.65	16.65
Variable O&M Expense	2015 $/MWh	2.80	2.80
Capital Costs	2015 $/kW	1,011	1,163
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	6.88	6.67
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	6.98	6.77
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	50	50
Ramp Down Rate	MW/minute	50	50
Regulation Minimum Range	MW	184	178
Regulation Maximum Range	MW	368	357
Regulation Ramp Rate	MW/minute	50	50

Note: See Section 3.2.9 for discussions of generic H Class performance.

Source: Pace Global

Table 3-8: Reciprocating Engine Operational Assumptions

Generation Unit Type	Unit	Reciprocating Engine
		Diesel
Max. Unit Capacity	MW	17
Min. Unit Capacity	MW	5
Fixed O&M Expense	2015 $/kW-year	22.52
Variable O&M Expense	2015 $/MWh	8.01
Capital Costs	2015 $/kW	1,304
Heat Rate at 100% Rated Capacity	MMBtu/MWh	8.44
Unit Capacity Degradation	%	2.5%
Unit Heat Rate Degradation	%	1.5%
Annual Required Maintenance Time	Hours per Year	360
Unit Forced Outage Rate	%	2%
Unit Forced Outage Duration	Hours	40
Minimum Downtime	Hours	2
Minimum Runtime	Hours	2
Ramp Up Rate	MW/minute	2.5
Ramp Down Rate	MW/minute	2.5
Regulation Minimum Range	MW	5
Regulation Maximum Range	MW	17
Regulation Ramp Rate	MW/minute	2.5

Source: Pace Global

Table 3-9: GE LM6000 PG Sprint SC Operational Assumptions

Generation Unit Type	Unit	GE LM6000 PG Sprint SC
		Diesel
Max. Unit Capacity	MW	48
Min. Unit Capacity	MW	14
Fixed O&M Expense	2015 $/kW-year	20.77
Variable O&M Expense	2015 $/MWh	6.82
Capital Costs	2015 $/kW	1,315
Heat Rate at 100% Rated Capacity	MMBtu/MWh	9.78
Unit Capacity Degradation	%	2.5%
Unit Heat Rate Degradation	%	1.5%
Annual Required Maintenance Time	Hours per Year	180
Unit Forced Outage Rate	%	2%
Unit Forced Outage Duration	Hours	40
Minimum Downtime	Hours	1
Minimum Runtime	Hours	1
Ramp Up Rate	MW/minute	10
Ramp Down Rate	MW/minute	10
Regulation Minimum Range	MW	14
Regulation Maximum Range	MW	48
Regulation Ramp Rate	MW/minute	10

Source: Pace Global

3.2.4 Generation Options Development Methodology

Siemens considered multiple factors across four Futures and three Supply Portfolios in developing the potential future generation options for PREPA. These factors included:

- Capacity loss from units that will be retired (or relegated to limited use) for MATS compliance
- System capacity needed to meet expected normal evening power demand of approximately 3,000 MW, plus spinning reserve and allowance for the largest unit[18] out of service for maintenance
- Peaking resources assumed to be used only for levels of peak demand occurring less than 500 hours per year and for occasional use in system emergencies such as generating unit trips or loss of certain transmission resources
- Location on PREPA transmission network
- Existing power generation sites and space potentially available for new or replacement units
- Needed sizes of individual units
- Flexibility of portfolio to accommodate renewable generation, mostly daytime solar and wind requiring a steady decline in fossil generation throughout the morning and then a steady ramp-up in afternoon as solar and wind generation fades and demand rises to evening peak levels
- Heat rates for various classes of combined cycle units
- Dual fuel capability
- Potential for repowering existing units to obtain more capacity and better fuel efficiency in lieu of new unit builds
- Capital needed for new or repowered units
- Timing of projects to avoid excessive use of PREPA and on-island construction resources for too many projects underway at the same time, and to account for necessary development and permitting activities
- Available fuels in northern and southern potential generation sites
- Maximum loss of generation (largest unit trip)
- Ability to bypass steam in the event of steam turbine trips to keep gas turbines online until the system can react to the loss of supply
- Ability to complement and integrate renewable generation

3.2.5 Generation Options Development and Sizing

Siemens implemented the following work process to develop new generation options. Gas turbines and their corresponding combined cycle plants come in discrete sizes based on equipment offerings from a limited number of worldwide manufacturers. Siemens' approach

[18] The largest generating units presently are the Aguirre 1&2 steam plants. Once these and Cost Sur 5&6 are replaced, the largest unit may be a combined cycle unit of somewhat smaller size and the spinning reserve may be adjusted accordingly. The final adequacy of performance was done in PROMOD that considers explicitly the units outage rates and maintenance needs.

was to screen a large number of available combined cycle configurations from all major manufacturers based on published output and heat rate at standard conditions on natural gas. A limited number of cases from various manufacturers were selected for analysis in GT Pro software from Thermoflow.

Siemens prepared the GT Pro models to determine output and heat rate for each case at 85° F rating temperature, at full load and at a range of part load points to support the PROMOD analysis. Our 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 combined cycle with natural gas as primary fuel.

Oil firing capability is needed both for reliability in case of natural gas interruption and because natural gas is not available at certain sites and in certain Futures, in which cases fuel oil will be the only fuel. At the time any generation project is implemented, optimization studies can be performed to get the best performance under the conditions actually required and known at that time[19]. The analyses used for the IRP purposes are adequate to determine which portfolios are preferred.

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 similar enough characteristics that competitive bidding will be possible at the time a project is implemented.

For the smaller combined cycle cases, the competitive options may use a different number of trains, e.g., 2 x GE S206FA versus 3 x Siemens SCC-800 for a nominal 200-250 MW plant. 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 actual known conditions at the time.

Another concept adopted for the IRP planning purposes is that large new generating units are proposed as 1x1 combined cycles. The 1x1 configuration provides flexibility to locate at any desired site independently of other capacity expansions and to operate to the lowest minimum load if needed to accommodate solar/wind ramping. For sites with multiple CC units, 2x1 combined cycles can be considered at the project implementation stage. 2x1 combined cycles may have advantages in lower unit cost and slightly better heat rate. The larger Steam Turbine Generator (STG) may be an advantage or disadvantage[20] depending on whether the unit is part loaded, how often one of two GT trains is offline, frequency of

[19] As an example, Siemens performed an alternate sizing analysis for a Siemens F Class (SCC6-5000F) CC plant, optimizing for natural gas fuel and lower duct firing. Reducing the maximum duct firing net output (new & clean) from 411 MW to 357 MW reduces corresponding net heat rates from 7.415 to 6,942 Btu/kWh HHV. This is to be expected, as more duct firing generally increases heat rate. Maximum unfired net output also changes from 314 MW to 329 MW and corresponding unfired net heat rate improves from 7,214 to 6,817 Btu/kWh HHV. So the benefit of additional duct firing capacity for peak loads or spinning reserve must be weighed against the fuel efficiency benefit of a heat rate-optimized design if the CC plant is expected to dispatch most often in unfired mode.

[20] A 2x1 STG is twice as large as that of a 1x1 so it normally would have a proportionately higher minimum load. Assuming the same GT minimum load, the 2x1 with one GT running would have a higher minimum load than a 1x1 using the same GT. The actual magnitude of the difference should be weighed against other criteria in selecting the final configuration.

starts, ability to provide spinning reserve, etc. All these considerations can be weighed carefully at the time a specific project is planned.

For the purpose of the IRP, three combined cycles in a 1x1 configuration were considered to study the operation of small and flexible combined cycles. However, equivalent arrangements of small, flexible combined cycles are available in the industry, such as one combined cycle on a 3x1 configuration, which can be designed to provide an equally acceptable flexibility. The final configuration of a combined cycle to be selected for installation would depend on capital investment, its required flexibility for operations and/or site constraints.

3.2.6 Duct Firing

Another important point about the sizing of combined cycle units is the inclusion of supplemental duct firing to provide flexible capacity. A combined cycle plant has its best efficiency at full load in "unfired" mode. Gas turbines have excess oxygen in their exhaust and so additional fuel can be burned to raise the temperature of exhaust gas entering the Heat Recovery Steam Generator (HRSG). This allows additional steam production which can increase the steam flow to the STG and allow additional electrical output. We have increased the sizes of the STGs in the combined cycle designs to allow additional generation from duct firing, which may add up to 20 percent to the overall output of the combined cycle plant. Duct firing typically has an incremental heat rate in the range of 8,500 Btu/kWh to 9,000 Btu/kWh (HHV), which is not as good as the base combined cycle but usually as good as or better than peaking units and steam electric units with fired boilers.

Duct firing mode is useful to a power system by providing spinning or non-spinning reserve capacity. The combined cycle units can be operated at their efficient full load points, but the online STGs have additional capacity that can be ramped up quickly in the event of a call on spinning reserve. Depending on spinning reserve criteria, it may be necessary to have the duct burners on at a minimum firing level, but the efficiency penalty would be small.

The ultimate aim of the portfolios is to improve overall system efficiency and replace steam electric units that currently provide spinning reserve. Therefore, Siemens has included duct firing in all combined cycle configurations to provide some spinning reserve in addition to that which can be obtained by operating the units below their full, unfired load.

3.2.7 Load Following Capabilities

As noted earlier, a major criterion for new generation is to be able to reduce and increase load to follow the corresponding increases and decreases in solar and wind turbine generation on the grid each day. The newest generation of combined cycle plants incorporates special design features in the GTs and the HRSG/STG steam cycles and equipment to allow daily start/stop and fast start/fast ramp capability. Also, designs have been optimized to allow a lower minimum load than the typical 50 percent guideline for older combined cycle designs (40 percent).

Another way to provide more system load following capability is to incorporate smaller unit sizes. We have adopted both approaches by proposing multiple smaller combined cycle trains or a block of Reciprocating Engines (also called Internal Combustion Engines) for the first new project at Palo Seco site. Subsequent combined cycle units are from the large F and G/H Classes of 300 MW and up for a single train. This smaller size however comes at a penalty on the capital cost per kW.

J Class units were screened but they are at least 50 MW per unit larger than G/H Class and so would require higher spinning reserve. Also, there are fewer units operating in the worldwide fleet and less operational experience at this time. These units can be evaluated for suitability as specific projects are planned.

3.2.8 Repowering Options

PREPA did not provide any specific studies of repowering options, except for repowering of the Aguirre combined cycle 1&2 units using the Mitsubishi-Hitachi H-80 GTs (recently renamed H-100). This project does not add base-load capacity. The old 7B GTs are eight units that become surplus and potentially could be redeployed as peakers and/or for use in Hot Windbox Repowering for Aguirre Steam Units 1&2 and/or Costa Sur 5&6. But the project significantly improves the heat rate of Aguirre 1&2 CC units at a capital cost that is very likely to be less than any new combined cycle plant. So it makes sense to include the repowering to get better system efficiency without using incremental site space. We incorporated this option in all three portfolios. Table 3-10 shows the parameter of Aguirre 1&2 CC units repowering assumptions.

Table 3-10: Aguirre 1&2 CC Units Repowering Assumptions

Generation Unit Type	Unit	Aguirre CC Repower
		Natural Gas
Max. Unit Capacity	MW	263
Min. Unit Capacity	MW	105
Fixed O&M Expense	2015 $/kW-year	16.57
Variable O&M Expense	2015 $/MWh	4.77
Heat Rate at 100% Rated Capacity	MMBtu/MWh	7.58
Average Heat Rate at Maximum Capacity	MMBtu/MWh	7.59
Average Heat Rate at Minimum Capacity	MMBtu/MWh	10.22
Annual Required Maintenance Time	Hours per Year	360
Minimum Downtime	Hours	6
Minimum Runtime	Hours	6
Ramp Up Rate	MW/minute	25
Ramp Down Rate	MW/minute	25
Regulation Minimum Range	MW	105
Regulation Maximum Range	MW	263
Regulation Ramp Rate	MW/minute	25

Source: Siemens PTI, Pace Global

Siemens gave preliminary consideration to other repowering options at PREPA's existing steam electric units by considering two basic types of repowering:

- Heavily Fired Combined Cycle (Hot Windbox Repowering)
- New GT/HRSG Repowering (re-using existing STG)

For HFCC, we considered that we would add a gas turbine and duct the exhaust into the existing fired boiler windbox as a source of preheated combustion air. This generally results in a plant in which the GT represents about 15 to 25 percent of the total power and the existing STG about 75 to 85 percent. The HHV efficiency can increase to about 40 percent or better according to literature. We selected GTs of approximately the correct nominal size to fit the units at San Juan 9&10, Palo Seco 3&4, Aguirre 1&2 and Costa Sur 5&6. We included the Aguirre and Costa Sur units in Supply Portfolio 1 on this basis so that efficiency would be improved. These performance assumptions need to be confirmed by detailed studies if this approach is attractive. Table 3-11 shows the parameter of Aguirre 1&2 ST and Costa Sur 5&6 ST units repowering assumptions.

For combined cycle repowering, we assumed that the GTs generally would constitute about two times the capacity of the existing STGs to which they are matched. We selected GTs accordingly and produced conceptual sizing for one repowering at each site (San Juan 9&10, Palo Seco 3&4, Aguirre 1&2 and Costa Sur 5&6). We did not recommend any of these steam generation repowering for the portfolios, as arguably the performance would be similar to or slightly less attractive than a comparable new CC unit, and the capital costs may be slightly lower. By using the new combined cycles in the portfolios, PREPA can determine the overall generation requirements and then more specific studies can be performed of the feasibility and actual costs of repowering versus new combined cycles.

Table 3-11: Aguirre and Costa Sur ST Repowering Assumptions

Generation Unit Type	Unit	Aguirre ST Repower	Costa Sur ST Repower
		Natural Gas	Natural Gas
Max. Unit Capacity	MW	543	503
Min. Unit Capacity	MW	230	250
Fixed O&M Expense	2015 $/kW-year	30.57	34.31
Variable O&M Expense	2015 $/MWh	2.15	2.60
Heat Rate at 100% Rated Capacity	MMBtu/MWh	9.20	9.20
Average Heat Rate at Maximum Capacity	MMBtu/MWh	9.22	8.82
Average Heat Rate at Minimum Capacity	MMBtu/MWh	Unit 1: 9.86 Unit 2: 10.05	Unit 5: 9.84 Unit 6: 10.02
Annual Required Maintenance Time	Hours per Year	940	940
Minimum Downtime	Hours	48	48
Minimum Runtime	Hours	720	720
Ramp Up Rate	MW/minute	25	25
Ramp Down Rate	MW/minute	25	25
Regulation Minimum Range	MW	230	250
Regulation Maximum Range	MW	543	503
Regulation Ramp Rate	MW/minute	25	25

Source: Siemens PTI, Pace Global

3.2.9 Detailed Description of Future Generation Resources Screening

The following screening process was used, based on published data, to select the cases to be modeled in GT Pro. Note that the final GT Pro performance is somewhat different from the published figures, but the selections still fit the intended classes of size and efficiency. Another notable point is that generally as the combined cycle plants progress from F to G/H to J class, the unit size increases and the heat rate is reduced.

For large advanced combined cycles, we modeled the MHI 501J at 470 MW, 5,549 Btu/kWh, and the Siemens H at 410 MW, 5,691 Btu/kWh. Similar models include the GE 7HA and MHI M501GAC. The Siemens H has a slightly better heat rate than the MHI G. The GE H heat rate was virtually identical to the Siemens H, but GE does not have any operating 60 Hz H Class units at this time. Siemens has at least six H Class GTs operating in combined cycles in Florida, and three more in construction, so Siemens H was selected as the representative technology for this class.

For smaller F Class CCs, we considered Alstom GT24, GE S107F.03 and S107F.05, MHI M501F3 and Siemens SCC6-5000F. We modeled the Siemens unit for our target of approximately 300 MW, 5,990 Btu/kWh and the GE S107F.05 which has a slightly larger size at 323 MW but a better heat rate at 5,863 Btu/kWh. Actually, GT Pro has the GE unit slightly smaller and the Siemens unit slightly larger.

For Aero and small CCs, we considered five choices and modeled four. We eliminated the Rolls-Royce Trent 60 CC, because it has similar heat rate to the GE LM6000 CC and the Trent is a little larger. For a nominal 200 MW block, our competitive choices would be:

- 4 x LM6000 CC at 56 MW each, 6,308 Btu/kWh
- 3 x SGT-800 CC at 71 MW each, 6,189 Btu/kWh
- 2 x GE LMS100PB CC at 116 MW each, 6,569 Btu/kWh
- 2 x GE S106FA CC at 118 MW each, 6,199 Btu/kWh

All heat rates for screening are based on published figures, lower heating value (LHV), new and clean. The GT Pro models update the performance for site conditions and duct firing. For use in the portfolios, we included adjustments for average output and heat rate degradation over life.

Wärtsilä has been promoting their large 18.5 MW reciprocating engine, but MAN and Caterpillar also could bid for reciprocating units, albeit somewhat smaller unit sizes. Table 3-12 presents the future generation resources screening candidates.

Table 3-12: Future Generation Resources Screening Candidates

Class	Manufacture	Model	Configuration	ISO Output (kW)	ISO Heat Rate (Btu/kWh LHV)	ISO Heat Rate (Btu/kWh HHV)
J Class CC	MHI	M501J	1x1	470,000	5,549	6,143
G/H Class CC	MHI	M501GAC	1x1	412,400	5,735	6,349
	Siemens	SCC6-8000H	1x1	410,000	5,691	6,301
	GE	107H	1x1	400,000	5,690	6,299
F Class CC	Alstom	KA24-1	1x1	332,000	5,853	6,480
	GE	S107F.03	1x1	277,266	5,948	6,585
	GE	S107F.05	1x1	323,000	5,863	6,491
	MHI	M501F	1x1	285,100	5,976	6,616
	Siemens	SCC6-5000F	1x1	307,000	5,990	6,632
Aero or Small CC	GE	LM6000PF	1x1	55,804	6,308	6,984
	Rolls-Royce	Trent 60 DLE	1x1	66,678	6,364	7,046
	Siemens	SCC-800	1x1	71,400	6,189	6,852
	GE	LMS100PB	1x1	115,573	6,569	7,273
	GE	S106FA	1x1	118,400	6,199	6,863
Aero SC/Peaker	GE	LMS100PB	SC	99,400	7,695	8,519
	GE	LM6000PH	SC	51,000	8,020	8,879
	Rolls-Royce	Trent 60	SC	54,020	8,023	8,882
Reciprocating Engine	Wartsila	18V50SG	SC	17,382	7,627	8,444
Aguirre CC Repower	Hitachi	H-80 GT SC	SC	110,000	9,100	10,075
	Hitachi	H-80 CC	2x1	TBD	6,308	6,982
Hot Windbox Repower GT	GE	LM2500PJ	GT	22,719	9,345	10,346
	GE	MS5002E	GT	31,100	9,748	10,792
	GE	6B	GT	43,000	10,307	11,411
	GE	7B	GT	53,000	11,562	12,800
	GE	6FA	GT	77,577	9,574	10,599
	GE	7E	GT	88,718	10,192	11,284
	Siemens	SGT6-2000E	GT	112,000	10,066	11,144
	Hitachi	H-25	GT	32,000	9,806	10,856
	Hitachi	H-80 GT SC	SC	110,000	9,100	10,075

Source: Gas Turbine World 2013 Performance Specifications, Pace Global

The results of the GT Pro runs highlighted one unexpected difference from the screening analysis. The Siemens H Class was selected to represent the G/H Class combined cycle with a larger unit size and lower heat rate than the F Class combined cycle, represented by the GE S107F.05. This held true for the natural gas fired performance, but not for oil-fired performance, as the Siemens Power Generation H Class heat rate was higher and maximum duct fired output lower relative to F Class.

Upon investigation with Siemens Power Generation, we determined that the GT Pro data for the Siemens SGT6-8000H gas turbine is based on data that significantly understates actual oil-fired capability. The oil-fired data Siemens Power Generation provided to GT Pro was estimated conservatively before the H unit was tested on oil. Since most combined cycles in the world today use natural gas as a primary fuel, oil-fired performance usually is a lower priority.

We are not sure when Siemens Power Generation will update its published oil-fired performance to be more accurate. The Siemens oil-fired H performance, if used in the IRP, would understate what could be achievable in an actual project. So when analyzing the IRP cases in Portfolio 3, Future 2, when gas is not available for the H Class combined cycle, the IRP team substituted “Generic” H Class oil-fired output and heat rate in lieu of the actual Siemens Power Generation SGT6-8000H CC oil-fired performance.

The Generic H Class performance was determined by reviewing other OEMs' typical differences between gas and oil performance. These differences generally were found to be about 3 percent improvement in oil net HHV heat rate vs. natural gas and about 3 percent reduction in oil net output relative to natural gas. So these 3 percent adjustments were applied to the Siemens SGT6-8000H gas performance to develop the Generic H Class oil fired performance. The rationale for this adjustment is that similar performance could be obtained by getting a more realistic performance bid from Siemens or from other suppliers in case PREPA actually decided to implement H Class combined cycle projects in locations without natural gas fuel as part of its future generation expansion. This approach allows a reasonable comparison of Portfolio 2 (F Class) vs. Portfolio 3 (H Class) across Futures with and without natural gas fuel available[21].

[21] Subsequent to the IRP analyses, Siemens Power Generation did provide updated performance data to the Siemens IRP team. The updated performance was similar to that used for the "Generic" H Class oil fired case, thus validating the Generic case as representative of available H Class performance on oil.

Section

4

Renewable Generation

4.1 Introduction

Renewable Generation, when properly deployed and appropriately priced, can result in important benefits to the consumers. However, there are limits to the amount that can be economically integrated in a given system as shown in Siemens' "Renewable Sources Integration Study" and further confirmed with the results of this IRP study. Specifically PREPA's generating fleet has significant inflexibilities in its current configuration dominated by large steam turbine generating units, which can result in high levels of renewable energy curtailment (i.e. energy that is available but cannot be safely accepted in the system) for increasing levels of renewable generation. This curtailment has a cost that can make the renewable generation uneconomic.

In this section of the report we present the renewable generation that will be considered in the IRP study to assess how much it can be incorporated, as PREPA's fleet is modernized with improved flexibilities.

4.2 Utility Scale Renewable Generation (PPOA)

Various percentages of utility scale renewable generation RPS levels were considered in the study, specifically 10 percent, 12 percent, 15 percent and 20 percent, expressed as a percentage of the PREPA's power sales, the 3 latter as per Act 82-2010 RPS requirements. It is important to note that these target RPS levels do not account for the customer installed distributed generation (DG) and considering this generation, which is renewable and largely photovoltaic (PV), the actual renewable penetration in Puerto Rico is higher.

When considering the percentages to be studied as part of this IRP, it is important to refer to PREPA Renewable Generation Integration Study (February 14, 2014), where was founded that PREPA's current generation configuration can only safely integrate a limited amount of renewables, until new and flexible generation is added. For example, according to this study, the current generation infrastructure cannot safely integrate a 12% in 2015, as mandated in Act 82-2010. Hence, it will be possible to integrate this 12% or a higher percent when a new and flexible generation come online, which consists in the development of projects that takes several years. It is important to note that any renewable source installed in excess of the maximum capacity that the existing generation configuration can safely integrate, would have to be curtailed in order to protect the electrical system. One of the major disadvantages of curtailing renewable energy is that PREPA would have to pay for energy that is not using and, consequently, these are costs that the ratepayers will end paying.

On the other hand, it should be assessed the trend of development of utility scale renewable projects since the enactment of Act 82-2010. Regarding this aspect, the developing of major projects like these takes years to be completed. This has been the experience of PREPA with the current development of the projects that can be integrated with the existing generation configuration. In fact, the existing integrated renewable energy projects sum about 3.3 percent of the integrated renewable energy for compliance with the RPS, as shown later in Table 4-2.

Considering the above, it is not expected that the RPS can be met as mandated by Act 82-2010 due to the fact that: a) it is economically infeasible to meet the targets until the generating fleet is upgraded and curtailment impacts mitigated, and b) the current status of contracts that make it impossible to have 12 percent of the energy supplied from renewable resources by 2015 and very unlikely that 15 percent of the energy will be supplied from these resources by 2020. This is why a more realistic path was considered, consisting in reduced compliance targets of 10 percent by 2020, 12 percent by 2025, and 15 percent by 2035. However, the 20% mandate was simulated with the recommended portfolio as a sensitivity (See Section 9) to assess its impact on such portfolio.

In this section we provide a summary with respect of the projects that were considered for modeling of the renewable generation on the different assumed levels. The most demanding condition with respect of projects to be added is a 20 percent RPS level in 2035. Starting from 2014 conditions and considering the load projections in the study we estimate the following conditions for the 15 percent RPS level:

Table 4-1: Utility Scale Renewable Generation for 15 Percent RPS Level in 2035

Year 2035 Conditions

Peak Generation Total	2,927	MW
Sales + Net Metering	16,734,283	MWh
Energy DG (322 MW) @ 21 % Capacity Factor	592,566	MWh
Net Sales	16,141,718	MWh
Target RPS Level	**15%**	
Target PPOA Energy	2,421,258	MWh
PPOA PV + Wind MW in Projects	1,056	MW
Add PV @ 21% for required RPS level	161	MW
Total PPOA	**1,217**	**MW**
Average Capacity Factor	*23%*	
DG	322	MW
Total Renewable	**1,539**	**MW**
Total % Energy from Renewable	*18%*	
% Renewable as function of peak	*53%*	

As can be observed in the table above, 1,217 MW of utility scale renewable generation (also called PPOA generation from the contractual mode used by PREPA) is required to comply with the 15 percent RPS level considering at a capacity factor of 21 percent and that PPOA convey renewable energy certificates (REC). Also we note that considering the DG expected for 2035, the actual coverage of the customer energy by renewable is 18 percent. We also note that more than 50 percent of the daytime peak can be covered by renewable generation under these conditions.

Of the PPOA generation above 1,056 MW of projects have been selected for this study and are shown in Table 4-2. These projects were identified based on the contracts that PREPA has signed (totaling approximately 1,600 MW), given priority to photovoltaic projects (PV) and were modeled in PROMOD considering their approximate location. Note that the top 25 projects are either existing (shaded green) or are based on projects that have reasonable probability of being successful (shaded in blue) for a total of 614 MW. Note also that Horizon (project 18) is in pre-operation and the landfill projects are also constructed and it is expected that will start operation.

The next 18 projects (shaded in pink) were developed based on projects that have been identified, their location is known and detailed models for their representation in PROMOD[22] and PSS®E[23] have been developed. Note that there is significant uncertainty about the actual future of these projects in their current contractual form, however as their location has been screened we can reasonably assume that for the increased RPS level, either the project in which we based the model will proceed in its current form or a similar project will be carried out at this location. Note however that we did not include any wind turbine project as the onshore potential is rather low and these types of plants are becoming increasingly difficult to site in the island due to local opposition. Thus we concentrated on Photovoltaic (PV) projects, as indicated earlier.

It should be noted that the O&M and capital costs for renewable PPOAs are embedded in the prices paid for renewable generation as provided in the signed and valid contracts. The Renewable Energy Credits (RECs) prices are also included in the PPOA prices and are generally valued at $ 25/MWh for Wind Turbine Generation and $ 35/MWh for Photovoltaic. Table 4-2 presents the renewable PPOAs and the prices.

Table 4-2: PPOA Projects Considered in the Study

NUM	Name	Technology	Capacity (MW)	Capacity Factor	Cumulative RPS Level	Price ($/MWh)
1	AES Ilumina, LLC	PV	20	21%	0.2%	194
31	Pattern Santa Isabel, LLC	Wind	95	38%	2.2%	157
32	Punta Lima (Go Green PR)	Wind	26	28%	2.6%	156
46	San Fermín Solar Farm, LLC (Coquí Power, LLC)	PV	20	21%	2.8%	185
60	Windmar Renewable Energy , Inc. (Cantera Martinó)	PV	2.1	21%	2.8%	197
18	Horizon Energy, Inc. (Salinas Solar Farm)	PV	10	21%	2.9%	178
24	Landfill Gas Technologies of Fajardo, LLC	Landfill Gas	4	80%	3.1%	100
25	Landfill Gas Technologies of Fajardo, LLC (Toa Baja)	Landfill Gas	4	80%	3.3%	100
3	PV Project # 3	PV	20	21%	3.5%	163
4	PV Project # 4	PV	57	21%	4.2%	172
5	PV Project # 5	PV	20	21%	4.4%	160
7	PV Project # 7	PV	40	20%	4.8%	175
15	PV Project # 15	PV	20	21%	5.1%	165
16	PV Project # 16	PV	17.8	21%	5.3%	171
21	PV Project # 21	PV	33.5	20%	5.6%	167
30	PV Project # 30	PV	50	20%	6.2%	180
36	PV Project # 36	PV	20	21%	6.4%	185
39	PV Project # 39	PV	20	21%	6.6%	170
42	PV Project # 42	PV	20	21%	6.9%	170
43	PV Project # 43	PV	20	21%	7.1%	158
47	PV Project # 47	PV	25	19%	7.4%	163
48	PV Project # 48	PV	20	21%	7.6%	158
57	PV Project # 57	PV	20	21%	7.8%	165
62	PV Project # 62	PV	10	21%	7.9%	185
63	PV Project # 63	PV	20	20%	8.1%	185
8	PV Project # 8	PV	10	21%	8.3%	185
9	PV Project # 9	PV	30	21%	8.6%	185
10	PV Project # 10	PV	15	21%	8.8%	185
11	PV Project # 11	PV	30	21%	9.1%	185
12	PV Project # 12	PV	15	21%	9.3%	185
17	PV Project # 17	PV	30	21%	9.6%	185
22	PV Project # 22	PV	40	21%	10.1%	185
23	PV Project # 23	PV	20	21%	10.3%	185
27	PV Project # 27	PV	52	21%	10.9%	185

[22] PROMOD is the tool used by PREPA and large part of the industry to conduct production costs analysis.

[23] PSS®E is the tool used by PREPA and in general in the industry to conduct load flow and stability analysis.

NUM	Name	Technology	Capacity (MW)	Capacity Factor	Cumulative RPS Level	Price ($/MWh)
28	PV Project # 28	PV	20	21%	11.1%	185
34	PV Project # 34	PV	20	21%	11.4%	185
35	PV Project # 35	PV	20	21%	11.6%	185
41	PV Project # 41	PV	20	21%	11.8%	185
44	PV Project # 44	PV	20	20%	12.0%	185
45	PV Project # 45	PV	20	21%	12.3%	185
53	PV Project # 53	PV	30	21%	12.6%	185
54	PV Project # 54	PV	30	21%	12.9%	185
56	PV Project # 56	PV	20	21%	13.2%	185
	Total		**1,056**			

Note:

(1) The first 8 projects shaded in green are built and either operating or in final testing stages.

(2) The next 17 projects shaded in blue, have renegotiated PPOA contracts and hence reasonable probability of being implemented.

(3) The final 18 projects shaded in pink are other possible projects for which models had been developed.

Source: PREPA

In addition to the identified PPOA generation in this case 161 MW of generic PV generation are required to achieve the 15 percent RPS level and we propose for this generation to be concentrated on strong bus as not to affect local transmission.

Maintaining the geographical distribution of the known PV projects, the table below shows the five additional Generic PV projects proposed to achieve 15 percent RPS level.

Table 4-3: Additional Generic PV Projects Required for 15 Percent RPS Level in 2035

NUM	Name	Same Solar Profile as Project #	Technology	Capacity (MW)	Capacity Factor	Cumulative RPS Level
95	Generic PV -PONCE	4	PV	32	21%	13.5%
96	Generic PV - BAYAMOÓN	36	PV	24	21%	13.8%
97	Generic PV - MAYAGÜEZ	47	PV	16	21%	14.0%
98	Generic PV -ARECIBO	30	PV	48	21%	14.5%
99	Generic PV -CAGUAS	63	PV	40	21%	15.0%
			Total	161		

These projects are proposed to be connected at the buses of Aguirre 115 kV, Vega Baja 115 kV, San Germán 115 kV, Mora 115 kV and J Martin 115 kV respectively. Note that these locations were selected for modeling purposes and while in general the renewable generation projects result in reduced loading on the bulk transmission system, as shown in Volume II, actual projects need to be subject to an interconnection process to assess their impact on the system.

For 20 percent RPS level, 1,656 MW of utility scale renewable generation (PPOA) is required as shown below and approximately 600 MW of generic PV needs to be considered. Considering the Distributed Generation in this case, the total energy from renewable is 23 percent. We note that at the time of the daylight peak, up to 68 percent of it may be covered by renewable generation, which is challenging from an operation’s stand point given the low inertia and variability of these sources.

Table 4-4: Utility Scale Renewable Generation for 20 Percent RPS Level in 2035

Peak Generation Total	2,927	MW
Sales + Net Metering	16,734,283	MWh
Energy DG (322 MW) @ 21 % Capacity Factor	592,566	MWh
Net Sales	16,141,718	MWh
Target RPS Level	**20%**	
Target PPOA Energy	3,228,344	MWh
PPOA PV + Wind MW in Projects	1,056	MW
Add PV @ 21% for required RPS Level	599	MW
Total PPOA	**1,656**	**MW**
Average Capacity Factor	*22%*	
DG	322	MW
Total Renewable	**1,978**	**MW**
Total % Energy from Renewable	*23%*	
% Renewable as function of peak	*68%*	

Table 4-5 shows the allocation of the required 600 MW of generic PV to the selected areas for modeling.

Table 4-5: Additional Generic PV Projects Required for 20 Percent RPS Level in 2035

NUM	Name	Same Solar Profile as Project #	Technology	Capacity (MW)	Capacity Factor	Cumulative RPS Level
95	Generic PV -PONCE	4	PV	120	21%	13.5%
96	Generic PV -BAYAMOÓN	36	PV	90	21%	13.8%
97	Generic PV -MAYAGÜEZ	47	PV	60	21%	14.0%
98	Generic PV -ARECIBO	30	PV	180	21%	14.5%
99	Generic PV -CAGUAS	63	PV	150	21%	15.0%
			Total	600		

For 2025 there are sufficient projects identified to achieve the 12 percent RPS level (956 MW) and no generic PV is required. These projects still include 342 MW of low probability projects (# 8 to 44 in Table 4-2) and their location is considered approximate.

We note that as before that with the DG, the RPS Level is in reality 14 percent and 40 percent of the daytime peak can be supplied from renewable as shown in Table 4-6 below.

Table 4-6: Utility Scale Renewable Generation for 12 Percent RPS Level in 2025

Peak Generation Total	2,913	MW
Sales + Net Metering	16,657,226	MWh
Energy DG (198 MW) @ 21 % Capacity Factor	364,755	MWh
Net Sales	16,292,471	MWh
Target RPS Level	**12%**	
Target PPOA Energy	1,955,097	MWh
PPOA PV + Wind MW in Projects	956	MW
Add PV @ 21% for required RPS Level	-	MW
Total PPOA	**956**	**MW**
Average Capacity Factor	*23%*	
DG	198	MW
Total Renewable	**1,155**	**MW**
Total % Energy from Renewable	*14%*	
% Renewable as function of peak	*40%*	

As in 2020, there are sufficient projects identified to achieve the 10 percent RPS level (784 MW) and no generic PV is required. These projects include 170 MW of low probability projects (# 8 to 22 in Table 4-2) and their location is considered approximate.

In this case considering the DG, the RPS level is in reality 11 percent and 32 percent of the daytime peak could be supplied from renewable, as shown in Table 4-7 below.

Table 4-7: Utility Scale Renewable Generation for 10 Percent RPS Level in 2020

Peak Generation Total	2,920	MW
Sales + Net Metering	16,694,873	MWh
Energy DG (138 MW) @ 21 % Capacity Factor	253,325	MWh
Net Sales	16,441,548	MWh
Target RPS Level	**10%**	
Target PPOA Energy	1,644,155	MWh
PPOA PV + Wind MW in Projects	784	MW
Add PV @ 21% for required RPS level	-	MW
Total PPOA	**784**	**MW**
Average Capacity Factor	*24%*	
DG	138	MW
Total Renewable	**922**	**MW**
Total % Energy from Renewable	*11%*	
% Renewable as function of peak	*32%*	

4.3 Distributed Generation

Distributed Generation is customer installed generation that results in a net reduction of the load served by PREPA. By regulation, the maximum installed capacity allowed in the transmission and subtransmission system is 5 MW. For the net metering program the maximum capacity allowed in the distribution system is 1 MW. Actually, there are a considerable number of projects proposed in transmission and distribution systems in the stage of study and endorsement, so that a high penetration of renewable distributed generators projects is projected, and yet there is not a DG cap limit. Also there are a high number of interconnection requests for DG greater than 1 MW for the subtransmission system, without PREPA's MTRs, which has an adverse impact over the PREPAs system. As a mitigation measure PREPA requires to DG greater than 1 MW to include power ramp rate control (+/-10 percent power output) or the requirement of frequency response.

The DG generation is behind the meter owned by the customers and the only impact is a reduction in the load that needs to be supplied by PREPA and PREPA's PPOA's (both renewable and thermal). The DG generation was not considered for the RPS compliance and with no RECs credit assumed.

It has some hidden costs to PREPA however, as much of this generation is photovoltaic and PREPA needs to supply the load during night time. Thus there are no savings in the generating fleet capacity or the transmission and distribution system, but the energy is priced as if there were. Also Distributed Generation changes the voltage profile of the distribution system resulting in the need for advanced voltage compensation. The distributed generation was modeled in this study as indicated below.

There are 60,885 kW of distributed generation installed, including net-metering and generation without a net-metering contract that was in service by February 1, 2015. This generation is distributed as follows:

Table 4-8: DG Installed Capacity (kW)

	Not in Net Metering Total			Net Metering Total					
Area Num[24]	Residential	Commercial	Transm.	Residential	Secondary	Primary	Transm.	**Total**	**%**
1	615	1,461	93	1,494	385	2,453	6,000	12,501	21%
2	777	1,088	2,749	1,582	239	2,670	1,204	10,309	17%
3	80	365	14	708	239	2,225	1,500	5,130	8%
4	215	504	2,947	1,624	609	2,991	1,000	9,891	16%
5 - 6	214	419	2,836	1,391	567	2,077	1,260	8,765	14%
7	188	782	1,118	825	762	275	1,686	5,634	9%
8	1,932	1,202	606	1,854	1,031	1,531	500	8,655	14%
	4,020	**5,822**	**10,363**	**9,478**	**3,832**	**14,221**	**13,149**	**60,885**	

Most of this generation is in the North of the island, largely in parallel with the location of the load, as shown below.

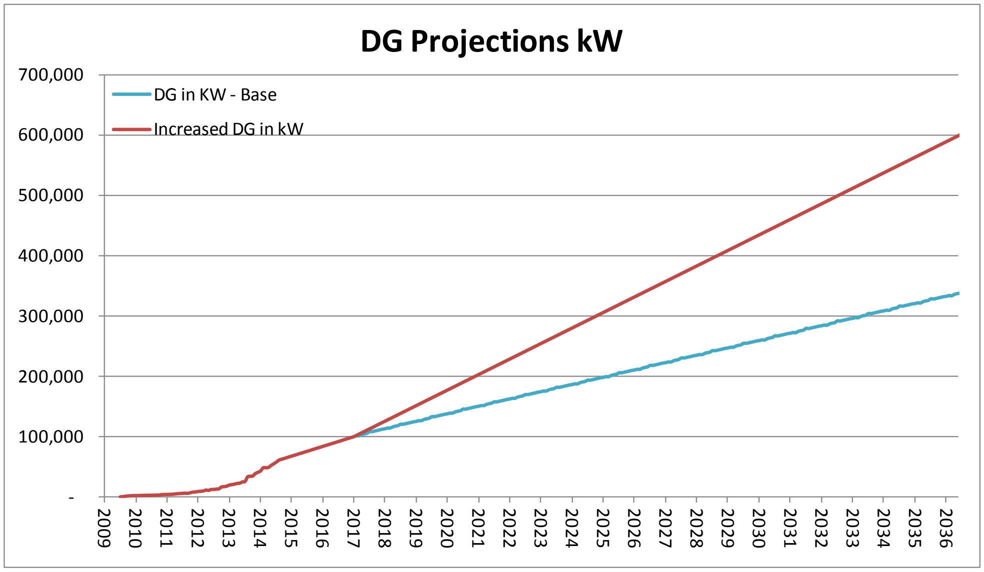
Table 4-9: DG Capacity by Area (MW)

Totals	**%**	**MW**	**Note**
North	71%	43	S. Juan, Bayamón, Carolina, Caguas & Arecibo
South	14%	9	Ponce
West	14%	9	Mayagüez
Total	100%	61	

PREPA provided projections for this DG as shown in the figure below where we observe that DG is expected to reach close to 350 MW by the end of the period under analysis, under the base projection. This base projection was used under Futures 1 to 3 and under Future 4 was assumed to almost double reaching 600 MW. This is shown as "Increased DG" in the figure below.

[24] These are the areas in which PREPA's transmission system is divided 1= San Juan, 2 Bayamón, 3 Carolina, 4 Caguas, 5 Ponce East, 6 Ponce West, 7 Arecibo and 8 Mayagüez.

Table 4-10: DG Capacity Projections



This DG by its nature is embedded in the distribution system and its impact is seen as aggregated at the transmission level substations. Therefore in this study we modeled it as “lumped” generation at selected strong substations to avoid distorting the use of the transmission, while maintaining the general location of the distributed generation by area.

The tables below show the modeled amount of PV generation and the substation where it was represented, for the base case and the increased case. The expected capacity factor is 21 percent, but for modeling the hourly profile was selected as similar to the closest point for which there was an estimation of PV production based on meteorological conditions.

Table 4-11: Base DG Production Forecast for Selected Dates and Allocation by Substation

Area Num	Proposed Bus	2/1/2015	7/1/2015	7/1/2020	7/1/2025	7/1/2035
1	88- SJSP	12.5	13.9	28.3	40.7	66.1
2	45 -Bayamón 115	10.3	11.5	23.3	33.6	54.5
3	85 - S. Llana	5.1	5.7	11.6	16.7	27.1
4	21 - Caguas	9.9	11.0	22.4	32.2	52.3
5 - 6	8 - Jobos	8.8	9.7	19.8	28.5	46.4
7	38 - Dos Bocas	5.6	6.3	12.7	18.3	29.8
8	277 Mayagüez TC	8.7	9.6	19.6	28.2	45.8
	Total Base	**60.9**	**67.6**	**137.7**	**198.3**	**322.1**

Table 4-12: Increased DG Production Forecast for Selected Dates and Allocation by Substation

Area Num	Proposed Bus	2/1/2015	7/1/2015	7/1/2020	7/1/2025	7/1/2035
1	88- SJSP	12.5	13.9	36.4	62.8	116.1
2	45 -Bayamón 115	10.3	11.5	30.0	51.8	95.8
3	85 - S. Llana	5.1	5.7	14.9	25.8	47.7
4	21 - Caguas	9.9	11.0	28.8	49.7	91.9
5 - 6	8 - Jobos	8.8	9.7	25.5	44.0	81.4
7	38 - Dos Bocas	5.6	6.3	16.4	28.3	52.3
8	277 Mayagüez TC	8.7	9.6	25.2	43.5	80.4
	Total Base	**60.9**	**67.6**	**177.3**	**306.0**	**565.6**

Section

5

Fuel Infrastructure Review

A summary of fuel infrastructure relevant to the existing and proposed generation addressed in IRP is provided in this section.

5.1 Purpose and Objectives

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

- Evaluate sources of Natural Gas delivered to Puerto Rico as Liquefied Natural Gas (LNG).
- Identify gas/LNG transport infrastructure needs relative to primary generation sites of Palo Seco, San Juan, Costa Sur, and Aguirre.
- Identify alternate liquid fuels, attractiveness, and deliverability.
- Identify current liquid fuel infrastructure relevant to IRP generation options.

5.2 Overview of Key Findings

PREPA historically has relied principally on a combination of heavy fuel oil (HFO), oil distillate, coal and natural gas for power generation. In 2014, HFO, oil distillate, and coal fuel consumption accounted for 61 percent of the island's total fuel consumption for power generation[25]. The EcoEléctrica LNG facility near Costa Sur began importing natural gas in 2000 to fuel the EcoEléctrica combined cycle power plant. A second LNG terminal is planned for installation at Aguirre in the next few years. However, these natural gas terminals as permitted have no further capacity available for fueling electric generation beyond the current units at Costa Sur and Aguirre. In order to comply with the new stricter emission controls resulting from the U.S. EPA MATS regulations, and changes to the New Source Performance Standards (NSPS), PREPA must consider greater use of natural gas and other operational changes.

As a power generation fuel, natural gas is generally superior to HFO and oil distillates. The main potential benefits include lower air emissions, higher efficiency, greater operating flexibility, and lower costs.

The inherent sulfur and particulate content of natural gas is extremely low. Carbon dioxide emissions from natural gas combustion also are lower than for liquid fuels. With state-of-the-art controls such as low-NOx combustors, NOx emissions can be lower as well.

Use of clean fuel such as natural gas allows the use of advanced combined cycle technology, which is the most fuel-efficient thermal power generation technology available today. Advanced gas turbines cannot fire HFO because of its high ash content.

A further benefit of modern combined cycle technology is its ability to operate with frequent starts and stops and fast load changes. PREPA needs these features in order to accommodate growing levels of renewable generation that varies significantly throughout the day. PREPA's HFO-fired steam electric generating units cannot be cycled on and off without causing greater stresses that create risk of damage leading to reduced reliability and increased maintenance cost.

[25] Source: PREPA January 2015 monthly report

Natural gas generally is significantly less expensive than premium liquid fuels such as distillate oil and diesel. The benefits of natural gas can be obtained only if this clean fuel can be cost-effectively delivered to Puerto Rico and then distributed to power generation locations. The need for expansion of the island's LNG import capability and natural gas distribution pipelines requires significant new fuel infrastructure investments to realize Puerto Rico's potential benefit from greater natural gas use for power generation.

The U.S. mainland has several LNG terminals and an extensive network of natural gas transmission and distribution pipelines that operate safely and effectively to serve energy needs in the areas of power generation, industrial, commercial and residential energy. Puerto Rico has much more limited geographic needs, but LNG terminals and pipelines still can play important roles in sourcing cleaner and potentially less expensive fuel such as LNG, and in transporting natural gas in vapor form to high volume users. Such a natural gas supply system provides 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 from among various fuel suppliers, as discussed below.

The EcoEléctrica LNG terminal has been operating successfully since 2000 and has expanded natural gas supply beyond its own 507 MW combined cycle unit to include supply to PREPA's Costa Sur generating plant. EcoEléctrica has potential for expanded natural gas delivery that would require permitting of the currently in stand-by regasification capacity. A major increase in LNG terminal throughput could require some modifications, possibly including a second LNG storage tank[26]. It must be noted that EcoEléctrica is a private company and expanded natural gas supply from this terminal would require PREPA, at minimum, to contractually commit to a long-term natural gas processing and/or purchase agreement to justify infrastructure investments.

PREPA is well advanced in planning, permitting, and contracting for a second Puerto Rican LNG terminal, AOGP. Should this effort succeed, a high volume of natural gas will be available to support significant generation at the Aguirre site. If AOGP does not proceed, PREPA may consider other LNG supply options. In the meantime, HFO and diesel will continue to be primary fuels at Aguirre at ultimately a higher cost than for power generated using LNG. Also, the timeline for MATS compliance by the Aguirre steam units will be longer, which will be undesirable and require negotiation with U.S. EPA for an extension to the compliance deadline.

PREPA has also begun studies of an additional LNG receiving terminal in the San Juan area. Current generating units using HFO will be replaced, retired or declared limited use in several years to achieve MATS compliance at San Juan and Palo Seco sites. The replacement generation plant(s) for these sites will be capable of natural gas and distillate firing. A northern LNG terminal would provide significant cost savings relative to the alternative distillate fuel.

An alternative to a northern LNG terminal may be a natural gas pipeline. The source of natural gas to supply such a pipeline would require careful study. Assuming natural gas supply from EcoEléctrica could be expanded, a natural gas pipeline would be required from there to San Juan and Palo Seco. This and other options are discussed in the sections below, including the required flow capacity based on the generation proposed in the IRP study. A pipeline with one segment from Costa Sur to Aguirre and a second segment from Aguirre to San Juan, with a lateral to Palo Seco, would support the generation needs at the two northern sites. Planning such a project must consider the pipelines' costs as well as permitting feasibility.

Another natural gas supply alternative is the delivery of LNG to the northern side of the island using ISO containers. This mode of LNG 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 41 m^3 (10,800 gal) capacity for up to a 90 day storage period.

There are numerous LNG suppliers available in the U.S. and internationally that utilize these systems. LNG ISO containers potentially could be delivered to the San Juan port (and/or to Ponce container

[26] 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.

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 ISO containers could provide an interim solution that could deliver LNG to the San Juan 5&6 CCs while other LNG delivery infrastructure is being permitted and constructed.

The practicality of delivering the large volume of LNG required for both Palo Seco CCs and San Juan CCs must be assessed. The San Juan port directly adjacent to the San Juan power plant already has a large capacity container terminal that could support a significant number of 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 empties carried back on the return trip. LNG containers[27] also could be used to deliver some volumes of LNG to peaking sites such as Cambalache and Mayagüez. Whether this volume of container movements is practical should be studied if pipeline transport of LNG is not permitted.

If additional LNG supplies and transportation cannot be developed, other potential liquid fuels such as propane, ethane and biofuels could be considered. These fuels historically had higher prices than distillate oil, which generally is available as a power generation fuel. Recent increases in ethane and propane production associated with U.S. shale gas production (i.e., “fracking”) have led to market imbalances that have depressed the prices of these products. Efforts are already underway to correct such imbalances, as chemical manufacturers are expanding ethylene and related products’ manufacturing in the U.S., which will absorb some of the excess supply. Some firms are expanding ethane export capacities to supply Europe and other regions as well.

The Siemens view is that ethane and propane prices will stabilize at higher levels later in this decade and may not be attractive relative to distillate. So there may be some near-term opportunities to take advantage of such fuels, but this likely would be on an interim basis only, until more readily-available LNG supplies and associated infrastructure can be developed. The cost and availability of biofuel continues to be largely dependent on location and at a higher cost than comparable distillates. Siemens does not expect liquid biofuels to be a cost-competitive alternative to distillate within the time period required for needed PREPA fuel infrastructure decisions discussed in this analysis.

PREPA already has significant infrastructure for HFO and distillate oil.

5.3 Conclusions and Recommendations

Supplies of cleaner and more cost-effective fuels are needed on both the southern and northern sides of Puerto Rico in order to best meet the generation and environmental compliance requirements facing PREPA. Siemens has concluded that there currently exists insufficient information to recommend a single path forward to resolve PREPA’s fuel infrastructure needs. However, Siemens believes the work that has been completed to date does identify several fuel infrastructure alternatives available to PREPA. Therefore, Siemens recommends that PREPA continue to develop further information on each of the alternatives discussed below:

1. Continue to pursue development of AOGP. This will afford the earliest MATS compliance for the Aguirre 1&2 steam electric units while reducing the fuel cost for the existing Aguirre CC 1&2 units and for future generation at Aguirre that ultimately will replace Aguirre steam units with more flexible and efficient combined cycle units or repower them.
2. Continue studies of LNG delivery directly to San Juan area by LNG carrier to an onshore receiving and regasification terminal. For the purpose of the IRP, in Future 3 Siemens assumed an LNG terminal at San Juan by July 1, 2022 for estimated capital costs of $501 million including $436

[27] 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. EcoEléctrica already received (in 2014) FERC approval of certain piping modifications to support development of an LNG trailer loading facility to be developed by Gas Natural Puerto Rico, Inc. (GPNR).

million for LNG terminal and $65 million for pipeline from San Juan to Palo Seco based on inputs from PREPA. Annual fixed operating costs are assumed at similar rates as the EcoEléctrica LNG terminal.

3. Undertake new studies of pipeline options to deliver natural gas to San Juan and Palo Seco sites, along with development of natural gas supply options in the South to feed such a pipeline.
4. Consider undertaking preliminary studies of additional fuel supply and infrastructure options including:
    a. Options for LNG delivery in ISO containers for interim or long-term supplies to selected power generating units.
    b. Options for delivery of LNG to certain peaking sites using LNG trailers loaded from on-island bulk LNG storage tanks.

An expanded discussion of these topics in covered in the sections below.

5.4 Data Provided for Review

The following documents were provided relevant to fuel infrastructure:

1. Galway Energy Advisors LLC, LNG and Natural Gas Import and Delivery Options Evaluation for PREPA's Northern Power Plants – Feasibility Study & Fatal Flaw Analysis, 2nd DRAFT REPORT, June 1, 2015
2. Gasoducto del Norte, North Coast Pipeline (Gasoducto del Norte), Contract Number 2008-P00009, Power Technologies Corporation, Work Order 1 Report, August 2008
3. CSA Group, Route Selection Study for a Natural Gas Fuel Oil Transmission Line, Oct 2000
4. Final Preliminary Engineering and Field Survey Report by Trigon EPC, Oct 6, 2006

5.5 Fuel Infrastructure Options Analysis

This section contains brief discussions of relevant fuels and associated infrastructure as follows:

- LNG Import and Regasification Terminals
- Natural Gas Pipelines
- LPG/Propane, Ethane
- Light Distillate Oil, Diesel
- HFO/No. 6 Oil

5.5.1 LNG Import and Regasification Terminals

To date, there is only one operating LNG import terminal in Puerto Rico, the EcoEléctrica LNG facility in Peñuelas, which was commissioned in March 2000 to supply the EcoEléctrica power plant (507 MW) on the Southwestern coast.

PREPA has proposed a floating LNG import terminal AOGP to supply natural gas to PREPA's existing Aguirre Power Complex in Salinas, Puerto Rico. Figure 5-1 shows the general location of both LNG import terminals.

In addition, PREPA has commissioned conceptual studies of facilities to receive LNG on the North side of the island, near San Juan.

Figure 5-1: Puerto Rico LNG Terminal Map

Source: Pace Global, AOGP, EcoEléctrica, Google Earth

5.5.1.1 EcoEléctrica

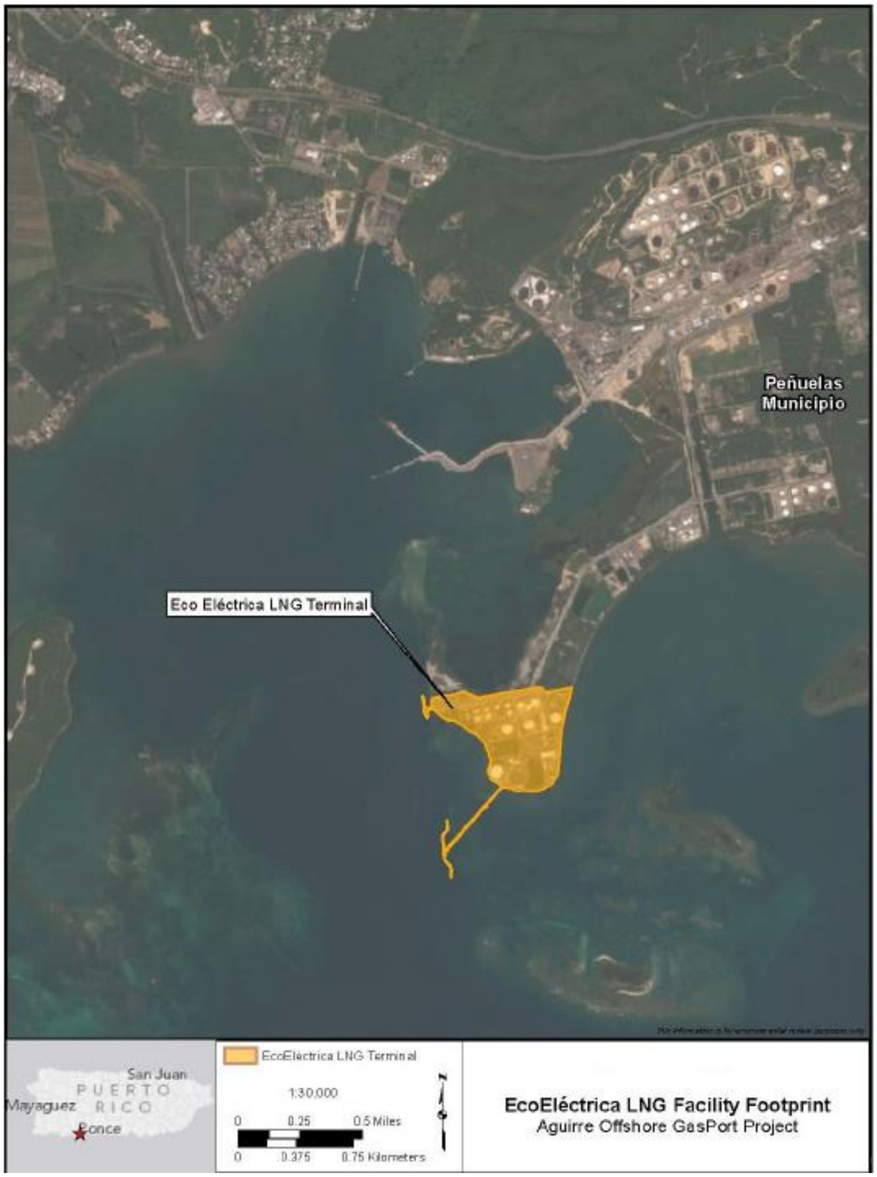
EcoEléctrica is a Federal Energy Regulatory Commission (FERC) regulated facility that began commercial operation in March 2000. The facility currently receives about 24 LNG cargos per year. GDF Suez supplies the LNG from Trinidad and Tobago under a 20-year contract for 0.5 MMTPA expiring in 2019. Currently, EcoEléctrica has storage capacity of 1,000,000 barrels of LNG[28], and it is the only facility on the island with the capability to import, store, regasify, and export natural gas.

In 2012, EcoEléctrica expanded the regasification capacity to supply natural gas for Costa Sur 5&6 steam units, each with a capacity of 410 MW. This plant was retrofitted for dual fuel operation in 2011. Based on original FERC application, EcoEléctrica was approved to construct two 1-million-barrel (160,000 cubic meters) LNG storage tanks. However, the second storage tank was never constructed and Commission authorization to construct the second tank has lapsed. However, the space remains available to construct the second tank if needed.

On June 19, 2014, FERC issued an approval for the EcoEléctrica facility to amend its previous authorization to construct and operate LNG supply pipelines to Gas Natural Fenosa's (47.5 percent ownership of the EcoEléctrica facility) proposed LNG truck loading facility, which will be utilized to distribute LNG by truck to various industrial end-users in Puerto Rico. Figure 5-2 shows the location of EcoEléctrica import terminal.

[28] Source: Final Environmental Impact Statement for Aguirre Offshore GasPort, LLC's Aguirre Offshore Gas Port Project under FERC Docket: CP13-193.

Figure 5-2: EcoEléctrica LNG Import Terminal Map



Source: FERC

5.5.1.2 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 (AOGP) to supply natural gas to PREPA's existing Aguirre Power Complex in Salinas, Puerto Rico.

AOGP facility would consist of an offshore berthing platform, a floating storage and regasification unit (FSRU), and a 4.0-mile-long, 21-inch outside diameter subsea pipeline connecting to the Aguirre Power Complex. AOGP is being developed with cooperation between Excelerate Energy, LP and PREPA.

AOGP will provide LNG storage capacity and sustained deliverability of natural gas to the Aguirre plant, which would assist PREPA's plan to convert the Aguirre plant from fuel oil only to a dual-fuel generation facility, capable of burning diesel and natural gas for the combined cycle units and heavy fuel oil and natural gas for the thermoelectric plant. AOGP facility would have a LNG storage capacity of 150,000 cubic meters and a natural gas send out capacity of 500 million standard cubic feet per day[29] (MMscf/d) to the Aguirre plant. Aguirre LLC is proposing to place the AOGP facility in service in 2016. However, due to permitting delay, Siemens assumed an AOGP commercial operation date of July 1, 2017. Based on data from Aguirre LLC, the estimated total construction period for AOGP facility is approximately 12 months, and total capital cost of AOGP facility is estimated at $385 million for all-in capital costs (including onshore and offshore component, permits, financing costs, etc.), excluding the capital cost related to fuel conversion of the Aguirre power plant based on PREPA's estimate. The annual fixed operating cost excluding debt service is estimated at approximately $77 million based on PREPA's estimates. Table 5-1 shows AOGP project capital costs and Figure 5-3 shows the location of AOGP.

Table 5-1: AOGP Project Costs

AOGP Project Capital Cost	Amount (thousand $2015)
Offshore Project	314,909
Onshore Project	27,346
Environmental Justice Mitigation	2,000
MOU Permitting Costs	5,000
Professional Services	6,325
PREPA Permits	164
Project Management	2,561
Total	**358,304**

Financing Summary	Amount (thousand $2015)
Equity Portion	20%
Debt Portion	80%
Financing Costs	2%
Construction Period (months)	24
Equity Amount	71,661
Debt Amount	286,643
Financing Costs	5,733
Interest During Construction	20,901
Total AOGP Project Cost	**384,938**

Note: Interest during construction is calculated based on an annual interest rate of 6.86 percent.
Source: PREPA, Pace Global

[29] Source: Final Environmental Impact Statement for Aguirre Offshore GasPort, LLC's Aguirre Offshore Gas Port Project under FERC Docket: CP13-193.

Figure 5-3: AOGP Location Map

Source: FERC

As of February 2015, FERC issued an approval of AOGP with certain conditions. A major condition is locating the undersea pipeline to avoid specific impacts to coral at the entrance to Bahía de Jobos. PREPA has undertaken a program of subsea soil borings to verify the suitability of the sea bottom geology for horizontal directional drilling (HDD) below the sea floor and coral resources. If suitable geology is found so that HDD and pulling the pipe through is feasible, PREPA expects this will allow the permitting to be completed and AOGP to proceed. Nevertheless, the IRP includes the evaluation of a potential future state in which AOGP does not proceed and natural gas from this project is not available to the Aguirre site steam and combined cycle power units.

5.5.1.3 LNG Options for North Puerto Rico Delivery

PREPA commissioned a Feasibility Study and Fatal Flaw analysis for delivery of LNG or CNG to the North side of Puerto Rico. In the initial study, 14 options were considered and all except one were ruled out. One issue was that floating storage units inside San Juan harbor require large impact zones in case of gas dispersion and fire events. Use of land-based full containment LNG tanks significantly reduces such impact zones, but only one site evaluated in the study met all necessary criteria.

A second major issue is that an offshore FSRU, similar to AOGP, was judged to impact the “pristine viewshed” from the fort and other tourist facilities at the mouth of San Juan harbor. In theory, an offshore FSRU could be located farther to the west, beyond the horizon (generally considered about 13 miles). However, the over-the-horizon option creates issues in routing a natural gas pipeline either offshore or onshore back to Palo Seco generation site. In the past there has been significant public opposition to both onshore and offshore pipelines, so the anticipated strong public opposition is problematic for an FSRU located at a greater distance from the primary generation sites at Palo Seco and San Juan.

The only feasible option, #14, would be for LNG delivery via large LNG carriers directly to the Port of San Juan, at a land-based receiving, storage, and regasification terminal with full containment LNG tanks located directly east of the San Juan power station site. This would avoid a subsea pipeline in

San Juan harbor from another site ruled out earlier near Pier 15/16. A land-based or submarine pipeline would be required to transport a portion of the gas from the delivery site, near the San Juan power plant on the southwest side of the San Juan Harbor, to the Palo Seco site on the west side of the San Juan Harbor.

Several of the 14 options reviewed contemplated the natural gas pipeline between the Palo Seco and San Juan power plant sites. At least one land-based routing option was identified that seems to meet criteria to be considered feasible. So natural gas can likely be delivered to both sites if it becomes available at either of the current northern plant locations.

If available in the North, natural gas would be used for the existing San Juan 5&6 combined cycle units as well as for new small combined cycle units planned at Palo Seco to replace the generation from San Juan and Palo Seco steam electric units. The San Juan and Palo Seco steam units are scheduled to be retired or declared limited use due to their lack of MATS compliance; PREPA also could locate a new large combined cycle unit at San Juan if natural gas is available both in the South and in the North. This would provide additional generation in the North and reduce dependence on transmission and exposure of generation to weather events in the South.

An LNG receiving and regasification terminal at San Juan would require dredging of 1.2 to 1.4 million[30] cubic yards of material to create a channel suitable for LNG carriers of 85,000 m^3 to 145,000 m^3. The Army Corps of Engineers (ACOE) has indicated to PREPA that an active spoils site can be used to dispose of dredge material. ACOE also indicated that it can take a very long time to get congressional appropriations for dredging. But if PREPA is able to fund the dredging, it can be permitted in a one to two year time frame to support LNG terminal development.

After the initial dredging to create a channel suitable for LNG vessels, it is possible that long-term maintenance dredging may be incorporated into ACOE's responsibility for dredging of San Juan Bay.

5.5.1.4 LNG Supply via ISO Containers

Another natural gas supply alternative is the delivery of LNG to the northern side of the island and to certain remote peaking sites using ISO containers. This mode of LNG 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 a self-contained, independent storage system with about 41 m^3 (10,800 gal) capacity for up to a 90 day storage period.

Several suppliers fabricate such units, with somewhat varying capacities and features. E.g., some units can be provided with onboard regasification capability if the required flow rates are relatively small. Units also can be provided with systems to deliver gas at certain pressures as required by users. For a large scale operation, a fixed regasification system would be required with piping manifolds to connect to and disconnect from banks of containers and pumps to reach necessary pressures before regasification.

There are numerous LNG suppliers available in the U.S. and internationally that utilize container LNG systems. The LNG ISO containers potentially could be delivered to the San Juan port (and/or to Ponce container 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 generally is more costly than bulk supply for large volumes of LNG, it could be evaluated to determine if it is a cost-effective option to the new small CCs at Palo Seco. In addition, the LNG ISO containers could provide an interim solution that could deliver LNG to the San Juan 5&6 CCs and Palo Seco plants while other LNG delivery infrastructure is being permitted and constructed.

[30] Dredging estimate is based on Army Dock estimate, Option 10 of LNG options study, pending refined dredging estimates to be prepared for the Option 14 proposed LNG terminal site at San Juan Port adjacent to PREPA's San Juan power plant site. Army dock is adjacent to San Juan Port and power plant site, so the dredging to get to San Juan Port would be reasonably similar to that required for Army Dock.

The practicality of delivering the large volume of LNG required for both Palo Seco CCs and San Juan CCs must be assessed. The San Juan port directly adjacent to the San Juan power plant already has a large capacity container terminal that could support a significant number of daily, full and empty LNG container movements. About 50 of these containers per day could be loaded onto trucks at the port for transport to Palo Seco, with empties carried back on the return trip. LNG containers also could be used to deliver some volumes of LNG to peaking sites such as Cambalache and Mayagüez.

Infrastructure investment for an LNG container solution typically includes purchase or lease of containers and transport vehicles (truck, rail cars, barge, and ship), regasification units such as Ambient Air Vaporizers, loading and measuring equipment, port and container-handling equipment at supply and receiving locations, and fire protection and safety equipment. Total infrastructure investment and operating and maintenance cost can range from US$1 to 3/MMBTU over and above the LNG commodity cost. A large number of operating staff, drivers and maintenance personnel may be required for a large scale application handling hundreds of containers per day.

Use of existing port facilities may be a significant benefit in avoiding investment and permitting, but the port charges must be considered in overall costs. Container delivery from offshore to Puerto Rico would require adequately sized sea vessels such as standard container ships. If LNG were sourced from U.S. mainland, the Jones Act would require vessels to be U.S.-flagged[31].

A supplier must be found with LNG access and capability to fill containers and load them for shipment, as well as unloading and handling returning empty containers. Many large scale U.S. LNG export terminals are planned, though some have been delayed due to the recent decline in world oil prices, which can affect the potential LNG revenues from certain customers. A few small scale LNG facilities are being developed for ship bunkering and other uses. However, these facilities may not all have the infrastructure needed to handle large numbers of containers. So a search will be needed to find the suppliers/projects targeting the containerized LNG market. Such firms may charge a premium price relative to bulk deliveries, so this must be determined and factored into economic analyses.

5.5.2 Natural Gas Pipelines

As noted earlier, the benefits of natural gas can be obtained only if this clean fuel can be delivered to Puerto Rico and then distributed to power generation locations that can use this fuel efficiently. Pipelines can play a significant role in upgrading Puerto Rico's power generation infrastructure and reducing power generation emissions and costs.

The U.S. mainland has an extensive network of gas transmission and distribution pipelines that operate safely and effectively to serve energy needs in the areas of power generation, industrial, commercial and residential energy. Puerto Rico has much more limited geographic needs, but pipelines still can play important roles in physical transport of natural gas, flexibility to enhance security of supply (backup), as well as commercial value in negotiating and selecting the most advantageous pricing over time from among various fuel suppliers, as discussed below. PREPA's primary uses for natural gas pipelines could be:

1. **San Juan-Palo Seco**: As noted in LNG section of this report, if natural gas can be delivered to the North, either as LNG or by pipeline from the South, PREPA will need a natural gas pipeline between San Juan and Palo Seco generation sites to support critical generation in both locations[32].

2. **Costa Sur-Aguirre:** A natural gas pipeline between Costa Sur and Aguirre has been attempted in the past (Gasoducto del Sur) and is technically feasible. Such a pipeline could serve several possible functions:

[31] Under the Jones Act, vessels must also be constructed in the United States, owned by U.S. citizens, and crewed by U.S. citizens and U.S. permanent residents.

[32] In the 2008 Gasoducto del Norte pipeline study, the main line carries fuel for both sites to a point, and then smaller laterals proceed to San Juan and Palo Seco.

- Deliver natural gas from EcoEléctrica to Aguirre as backup in case AOGP supply is interrupted.
- Deliver natural gas from EcoEléctrica to Aguirre in case AOGP is not permitted and implemented
- Deliver natural gas from EcoEléctrica to Aguirre in case EcoEléctrica natural gas price is lower, or to provide negotiating leverage to get a competitive price for LNG at AOGP.
- Deliver natural gas from EcoEléctrica to Aguirre to feed a further extension to transport natural gas to power plants in the North.

3. **South-North:** A natural gas pipeline from the South to the North would provide several advantages, including:

- Natural gas at lower cost could displace expensive distillate oil and diesel for existing and proposed generation at Palo Seco and San Juan.
- Additional clean, natural gas-fired new generation could be located near the northern load centers to minimize exposure to power interruptions from storms that may cause transmission outages or loss of generation in the South. If natural gas is available only in the South, then more generation would be sited there to take advantage of the lower natural gas cost. But more concentrated generation creates more risk of exposure to extreme weather events.

The feasibility, environmental impact, and costs of natural gas supply to the North via pipeline from the South would have to be compared to those same measures for an alternative direct LNG supply to the North.

A South-North pipeline could require the Costa Sur-Aguirre pipeline to source natural gas from EcoEléctrica, and may require expansion of the EcoEléctrica LNG terminal to provide additional supply to the pipeline system. If PREPA determines that a South-North pipeline could be a viable option in comparison to a northern LNG receiving terminal, then specific studies should be performed to determine the LNG source, terminal and regasification requirements and associated permitting issues to supply the pipeline.

A past proposal to bring natural gas to the North (Gasoducto del Norte, also known as Via Verde) by pipeline from EcoEléctrica LNG terminal encountered significant public opposition during permitting and was canceled. Several pipeline routings were 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[33].

Some of the opposition to Gasoducto del Norte (GdN) and its “preferred” pipeline routing was based on perceived environmental impacts of crossing the island’s remote, central mountain areas. Also, the project envisioned a fairly extensive network to serve all the different sites, which increased the cumulative impact of the project in terms of pipeline length, acres of Right-of-Way (ROW), stream crossings, affected landowners, etc. In this IRP, Cambalache and Mayagüez remain only as peaking units with relatively low Capacity Factors, and additional (non-PREPA) consumers of natural gas are not considered. So a much more limited pipeline from South to North could be considered, significantly reducing pipeline investment and environmental impacts and achieving higher pipeline utilization levels and cost effectiveness.

A South-North pipeline from Aguirre to San Juan area could be more practical than the “preferred” western routes considered earlier. 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 ROW 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.

[33] Some consideration also was given at that time to expanding generation at these sites to include combined cycle units.

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.

Note that some of these pipeline options also may require expansion of the EcoEléctrica LNG terminal. The pipelines themselves would be important elements of a comprehensive, diversified fuel procurement and delivery strategy to maximize fuel delivery reliability and minimize fuel cost in the long term.

The 2008 GdN report had a fairly extensive section on pipeline permitting issues and timing. The potential permitting issues cannot be understated, but it is clear that a well-defined project with limited scope can avoid some of the complexity and time that may be encountered if additional, related projects must be considered simultaneously. One consideration is whether the pipeline can be permitted locally, or whether certain related project elements, such as LNG terminals, may require a more extensive U.S. Federal National Environmental Policy Act (NEPA) review. So a well-considered permitting strategy is an essential element of any pipeline development plan.

5.5.2.1 Pipeline Capacity Requirements

To evaluate the flow requirements of potential natural gas pipelines, Siemens has considered the proposed IRP future states with respect to available fuels as follows:

Future 1: AOGP natural gas for Aguirre, no natural gas in the North

Future 2: No AOGP, no natural gas in the North

Future 3: AOGP natural gas for Aguirre, LNG or pipeline natural gas in the North

Future 4: Same fuels as Future 1

The proposed IRP generation portfolios are as follows. Where natural gas is available, this is the primary fuel; otherwise, fuel is distillate oil.

Portfolio 1: Small CC at Palo Seco, HFCC conversions at Aguirre and Costa Sur

Portfolio 2: Small CC at Palo Seco, F Class CCs to replace Aguirre and Costa Sur steam units

Portfolio 3: F Class CC at Palo Seco, H Class CCs to replace Aguirre and Costa Sur steam units

In the IRP, Future 2 has no natural gas supply at Aguirre or in the North, so no natural gas pipeline options apply for this future state. Only Future 3 has natural gas in the North (in addition to natural gas in the South). In theory, gas could be supplied by a new, northern LNG terminal or by pipeline from the South. Southern LNG supplies could be at EcoEléctrica, Aguirre or newly-developed LNG supply points.

Futures 1, 3, and 4 have AOGP natural gas at Aguirre, and natural gas pipelines are not required for the South except to the extent that:

- A pipeline between Costa Sur and Aguirre could serve as backup, allowing natural gas transfer between the sites, and/or could provide negotiating leverage in natural gas/LNG pricing.
- If AOGP natural gas volumes are limited to those currently considered for AOGP permitting, then any additional natural gas needed for future generation expansions at Aguirre might need to come from EcoEléctrica. However, as discussed below, it appears that the increased efficiency of new units will allow operation with lower maximum daily flows and at higher annual capacity factors without increasing the annual natural gas volumes at Aguirre.

5.5.2.2 North Natural Gas Fuel Requirements

IRP includes only one future state (Future 3) with natural gas supply to the North side of Puerto Rico. Table 5-2 shows existing and proposed generation and the daily natural gas volumes required for each generation portfolio in Future 3.

Table 5-2: North Generation Daily Natural Gas Volume Requirements

Potential Gas Fired Generation in North							
Location		Palo Seco	San Juan	Palo Seco	PS or SJ	San Juan	North Total
Units		6 Peakers	5&6 CCs	Small CCs	F Class CC	H Class CC	
Output	kW	120,000	400,000	216,061	369,166	393,282	
Heat Rate	Btu/kWh HHV	10,500	7,500	8,031	7,310	6,979	
Hourly fuel	MMBtu/hr HHV	1,260	3,000	1,735	2,699	2,745	
Daily Fuel	MMBtu/hr HHV	30,240	72,000	41,644	64,766	65,873	
Natural Gas Heat Content	Btu/SCF	1,000	1,000	1,000	1,000	1,000	
Daily Fuel	MMSCFD	30	72	42	65	66	

Estimated NG Requirements for Future 3, Gas in North							
Portfolio 1, HFCC	MMSCFD	30	72	42			144
Portfolio 2, Smaller CC	MMSCFD	30	72	42	65		209
Portfolio 3, Larger CC	MMSCFD	30	72		65	66	233

Note: Consumption is calculated at 100 percent output for the 24 hours.
Source: Pace Global

Past pipeline studies considered natural gas supply to the Palo Seco peaking units (120 MW), but since these have a low annual capacity factor, pipeline flow requirements could either include 30 MMSCFD for these or not[34]. The tables include the peaker fuel requirements, but this discussion will address only the flow needed for the base/intermediate load generating units. The latter would require about 125 MMSCFD for Portfolio 1 with only one new small CC installation (three trains totaling 216 MW) plus fuel for the existing San Juan 5&6 CC units. This is about the same volume considered in the Galway study of North island LNG delivery options (expressed as 125,000 MMBTU/day.)

Excluding peakers, natural gas volumes for Portfolios 2 and 3 would be about 190 to 214 MMSCFD for the existing and new units shown in Table 5-2 above. These portfolios have one more CC unit than Portfolio 1, and in Portfolio 3 the “small” combined cycle at Palo Seco is larger than in Portfolio 1 and 2.

For Portfolio 1, the pipeline between San Juan and Palo Seco would be sized for 42 MMSCFD, assuming the full natural gas volume for both sites is delivered first to San Juan.

If natural gas for the northern power generation units is sourced from EcoEléctrica, then a Costa Sur-Aguirre pipeline would be needed with at least the same flow capacity as the South-North segment. This flow would be 125 to 214 MMSCFD excluding any peaking unit supplies and excluding any consideration of natural gas transfers supporting the generation at Costa Sur and Aguirre.

5.5.2.3 Aguirre Natural Gas Fuel Requirements

Generation options at Aguirre and associated natural gas fuel requirements are shown Table 5-3. Total generation at Aguirre differs for Futures 1 and 4 vs. Future 3. In Futures 1 and 4, gas is available only in the South, so all the combined cycle units installed to substitute for the retired Aguirre 1&2 steam units are located at Aguirre. In Future 3, natural gas is available in the North, and so for geographic diversity and to decrease reliance on the transmission network, one Aguirre-replacement combined cycle unit is located at San Juan instead of at Aguirre. So the impact on Aguirre fuel requirements is one less combined cycle unit in Future 3. Note also that no natural gas is considered for peaking units at Aguirre.

[34] The low annual capacity factor may not justify the units’ conversion to dual fuel (natural gas/distillate) firing capability nor a larger pipeline size to support these units.

Table 5-3: Aguirre Generation Daily Natural Gas Volume Requirements

Potential Gas Fired Generation at Aguirre								
Location		**Aguirre**	**Aguirre**	**Aguirre** CC 1&2	**Aguirre** CC 1&2	**Aguirre**	**Aguirre**	**Aguirre Total**
Units		Steam 1&2 (converted to NG firing)	Steam 1&2 HFCC Repower	Existing (converted to NG firing)	Repowered (GTs Replaced)	F Class CC	H Class CC	
Output	kW	900,000	1,085,400	552,000	526,910	369,166	393,282	
Heat Rate	Btu/kWh HHV	9,650	9,200	11,140	7,582	7,310	6,979	
Hourly fuel	MMBtu/hr HHV	8,685	9,986	6,149	3,995	2,699	2,745	
Daily Fuel	MMBtu/hr HHV	208,440	239,656	147,583	95,881	64,766	65,873	
NG Heat Content	Btu/SCF	1,000	1,000	1,000	1,000	1,000	1,000	
Daily Fuel	MMSCFD	208	240	148	96	65	66	
Output increase from HFCC			120.60%					
Output, 3 CCs	kW					1,107,498		H vs F Output
Output, 2 CCs	kW					738,332	786,564	71.02%
Futures 1 and 4, AOGP, No Gas Available in the North								
NG conversion only	MMSCFD	208		148				356
Portfolio 1, HFCC	MMSCFD		240		96			336
Portfolio 2, Smaller CC	MMSCFD				96	194		290
Portfolio 3, Larger CC	MMSCFD				96		132	228
No. of new CCs						3	2	
Future 3, AOGP, Gas Available in the North								
NG conversion only	MMSCFD	208		148				356
Portfolio 1, HFCC	MMSCFD		240		96			336
Portfolio 2, Smaller CC	MMSCFD				96	130		225
Portfolio 3, Larger CC	MMSCFD				96		66	162
No. of new CCs						2	1	

Source: Siemens PTI, Pace Global

Adding generation quickly in the North is a high priority in order to accommodate the retirement of San Juan and Palo Seco steam units for MATS compliance. Only one or two new units are built for firing natural gas.

For the Aguirre site in the South, natural gas requirements are phased in over a longer time period than for the North. The main steps in implementing generation projects at Aguirre include natural gas fuel conversions of existing units, followed by repowering of existing units, and then addition of new, more efficient CC units to replace steam units[35].

AOGP provides natural gas to Aguirre 1&2 steam units at 55 percent annual capacity factor and to Aguirre CC 1&2 at 35 percent annual capacity factor. Both of these plants are converted to dual fuel capability with natural gas plus their current liquid fuels, HFO for Aguirre 1&2 and distillate for Aguirre CC 1&2. The maximum daily natural gas volume for these converted units is 356 MMSCFD. The annual volume corresponding to the permitted capacity factors is 60,700 MMSCF and the corresponding annual generation is about 6 million MWh.

[35] HFCC repowering of steam units occurs only in generation Portfolio 1, while new CCs are added in Portfolios 2 and 3.

Table 5-4: Generation Capacity Factors for AOGP Permitted Natural Gas Volumes

Generation Capacity Factors for AOGP Permitted Gas Volumes								
Location		**Aguirre**	**Aguirre**	**Aguirre**	**Aguirre**	**Aguirre**	**Aguirre**	**Aguirre Total**
Units		Steam 1&2 (converted to NG firing)	Steam 1&2 HFCC Repower	CC 1&2 Existing (converted to NG firing)	CC 1&2 Repowered (GTs Replaced)	F Class CC	H Class CC	
Output	kW	900,000	1,085,400	552,000	526,910	369,166	393,282	
Daily Fuel Use	MMSCFD	208	240	148	96	65	66	
Fuel Conversion Only	Annual Capacity Factor (AOGP limits)	55.00%		35.00%				46.7%
Annual Fuel Use	MMSCF	41,844		18,854				60,698
Daily Avg Fuel Use	MMSCFD							166
Annual Generation	MWh	4,336,200		1,692,432				6,028,632
Portfolio 1, HFCC	Annual Capacity Factor		47.84%		53.87%			49.56%
Annual Fuel Use	MMSCF		41,844		18,854			60,698
Daily Avg Fuel Use	MMSCFD							166
Annual Generation	MWh		4,548,297		2,486,638			7,034,935
Repower MWh Increase			104.89%		146.93%			
Generation Increase vs. Fuel Conversion Only								116.7%
Futures 1 & 4								
Portfolio 2, Smaller CC	Annual Capacity Factor					59.00%		
Annual Fuel Use	MMSCF					41,844		
Annual Generation	MWh				2,486,638	5,724,259		8,210,897
Generation Increase vs. Fuel Conversion Only	Percent							136.2%
Portfolio 3, Larger CC	Annual Capacity Factor						87.02%	
Annual Fuel Use	MMSCF						41,844	
Annual Generation	MWh				2,486,638		5,995,749	8,482,387
Generation Increase vs. Fuel Conversion Only	Percent							140.7%
Future 3								
Portfolio 2, Smaller CC	Annual Capacity Factor					88.50%		
Annual Fuel Use	MMSCF					41,844		
Annual Generation	MWh				2,486,638	5,724,259		8,210,897
Generation Increase vs. Fuel Conversion Only	Percent							136.2%
Portfolio 3, Larger CC	Annual Capacity Factor						174.03%	
Annual Fuel Use	MMSCF						41,844	
Annual Generation	MWh				2,486,638		5,995,749	>100% CF
Portfolio 3 - Adjusted	Annual Capacity Factor				94.00%		94.00%	
Annual Fuel Use	MMSCF				32,897		22,601	
Annual Generation	MWh				4,338,788		3,238,441	7,577,229
Generation Increase vs. Fuel Conversion Only	Percent							125.7%

Source: Siemens PTI, Pace Global

As future generation projects are implemented at Aguirre, each will need to obtain permits. These permits may allow changes in the natural gas fuel allocations and capacity factors as described above for AOGP permitting. For purposes of this study, we assume that there will be no increase in the total annual natural gas volume as permitted for AOGP, but that the fuel can be reallocated as the generation mix changes.

Five years after these fuel conversions and after AOGP enters service, the Aguirre CC 1&2 units are to be repowered with replacement gas turbines, improving heat rate from 11,140 to 7,582 Btu/kWh. This could allow an immediate increase in annual capacity factor to about 54 percent with no increase in annual fuel allocated to this CC plant, and at a substantially lower full load daily fuel consumption rate. Annual generation from these CC units would increase about 47 percent for same fuel. This repowering occurs in all three generation portfolios.

The next project, representing Portfolio 1, would be HFCC (Hot Windbox) repowering of the Aguirre 1&2 steam units. This is estimated conservatively to improve heat rate by about 5 percent to 9,200 Btu/kWh, while increasing output by about 20 percent. Consequently, for the same annual fuel allocation to these units, the annual capacity factor is reduced to about 48 percent, but total annual generation from these units is increased by about 5 percent.

After these repowerings, the HFCC and CC units could produce in aggregate almost 17 percent more generation for the same fuel allocations. In reality, the repowered CCs might be dispatched to an even greater extent due to their much lower heat rate, while the HFCC units would be dispatched less. This would increase the site total generation for same fuel even more. This shift might be limited by the minimum load capability of the HFCC units. But for Portfolio 1, there may not be a need for any additional natural gas to be provided by pipeline[36].

In Portfolios 2 and 3, HFCC conversions are not implemented. Instead, new CC units are installed and then the Aguirre 1&2 steam units are retired. In Futures 1 and 4, Portfolio 2, three new F Class CCs are installed. In Portfolio 3, two somewhat larger H Class CCs are installed. Because of the greater total capacity in Portfolio 2, the capacity factor for the same fuel allocation as the Aguirre 1&2 steam units is about 59 percent.

In Futures 1 and 4, Portfolio 3, the H Class CCs have a better heat rate than the F Class CCs. With only 2 CCs instead of 3, total new CC rated output is only about 70 percent of Portfolio 2. So Portfolio 3 units' capacity factor for same fuel is 87 percent and total site generation is over 40 percent more than the existing units with capacity factors as permitted for AOGP. In other words, the amount of fuel originally allocated for Aguirre steam units could support 2 new H Class CCs running at a high capacity factor and producing 40 percent more electricity than the steam units with the same fuel.

In Future 3, each of Portfolios 2 and 3 gets one less new CC at Aguirre, as one unit is located at San Juan instead. For Portfolio 2, the capacity factor for same fuel now increases to about 89 percent, and the total site generation is the same as in Future 1 and 4, a 36 percent increase; i.e., with one less F Class CC unit, the remaining two utilize the same available fuel and thus achieve a higher capacity factor.

For Portfolio 3, only 1 H Class CC cannot use all the fuel originally allocated from AOGP. Assuming such unit could be dispatched at its average availability of 94 percent, total site generation is about 25 percent greater than for fuel conversion only.

The conclusion from the analysis above is that there is a high probability that the proposed generation upgrades at Aguirre can be accommodated by the same allocation of AOGP natural gas as in the original permitting of AOGP. So there is no need for additional natural gas pipelines to serve Aguirre normal fuel requirements.

A natural gas pipeline from Costa Sur to Aguirre could be considered only to provide capability to shift natural gas volumes between the two sites for backup or fuel price negotiating leverage purposes. The range of capacities needed for such purposes could be up to the full volumes required at either site. Based on Aguirre fuel needs, this could be 160 to 356 MMSCFD. Costa Sur natural gas volumes would be lower at about 155 MMSCFD, as only 2x410 MW units are located there and these will consume about 80 percent natural gas for MATS compliance, with the balance of fuel as HFO.

The Aguirre fuel volumes can be reviewed based on the results of detailed dispatch analyses to determine whether Aguirre units would require higher annual CFs than those calculated above. If so, then a source for the additional natural gas volumes must be determined and pipeline capacity considered as needed.

Otherwise, capacity of a possible pipeline from Costa Sur to Aguirre is needed only to support delivery of natural gas to the North, as discussed in the North Fuel Requirements section above.

[36] If dispatch analyses favor even higher capacity factors for Aguirre units, then PREPA would need to consider the available sources for such additional volumes and whether pipeline capacity is needed to transport such volumes, e.g., from EcoEléctrica to Aguirre.

5.5.2.4 Pipeline Costs

The 2008 GdN report included one table of costs[37]. The Aguirre-San Juan Overland route (not the route along Route 52) was about 52 miles long before adjustment for terrain. A 20" pipeline size was assumed for a flow volume of 244 MMSCFD. 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.

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 about 40 miles. Using a cost of about $4 million per mile, this would cost approximately $160 million.

5.5.3 LPG/Propane, Ethane

Propane and ethane potentially could be considered alternatives to distillate or diesel fuel in the absence of gas or LNG. Gas turbines and some reciprocating engines can be designed to fire propane and/or ethane. The main issues are safety, pricing relative to distillate, availability of fuels, and infrastructure needed for delivery, storage and use.

5.5.3.1 Propane

EcoEléctrica is designed for use of propane as a backup fuel. Puerto Rico has significant propane delivery infrastructure for retail, commercial and industrial customers. Propane is delivered primarily by truck using pressurized containers at ambient temperature. The dominant propane supplier is Empire Gas, who can store 20 million gallons and sells about 100 million gallons per year. This entire volume is approximately equivalent to fueling a 300 MW combined cycle power plant at 60 percent annual capacity factor and heat rate of 7.0 MMBTU/MWh HHV. In 2014, Puma Energy entered the propane market, investing $46 million with storage of 4.2 million gallons at Bayamón. So for any significant long term power generation using propane, new, dedicated receiving, storage and delivery infrastructure would be needed.

5.5.3.2 Ethane

The primary worldwide uses for ethane are petrochemical manufacturing, specifically, production of ethylene and subsequent conversion to polyethylene, PVC and ethylene glycol. Siemens is not aware of any large scale manufacturing in Puerto Rico using ethane as feedstock. Very limited quantities of ethane are distributed in Puerto Rico for industrial purposes such as a specialty, low temperature refrigerant (R170).

Significant use of ethane as a power plant fuel would require development of dedicated receiving, storage and delivery infrastructure. Ethane is shipped as a cryogenic liquid, similar to LNG, but with a boiling temperature of -127 F vs. -263F for LNG. Ethane traditionally has been shipped in relative small ethylene carriers of up to 22,000 m^3 capacity, with most vessels under 10,000 m^3.

A 10,000 m^3 vessel delivering its cargo once per week could support a combined cycle power plant of about 900 MW with a 7.0 MMBTU/MWh HHV heat rate at 60 percent annual capacity factor.

5.5.3.3 Propane and Ethane Pricing

U.S. propane pricing has been depressed by higher volumes of production associated with the shale gas. Following the recent crash in crude oil prices, significant reductions in shale oil production have begun. How this will evolve over the longer term with lower crude prices remains uncertain. Recent wholesale FOB price of propane at Mount Belvieu, TX has been as low as $0.49/gallon ($4.68/MMBTU HHV).

[37] Page 4-17, Table 1.1, Estimated Engineering/Construction Costs for Alternative Routes

Siemens' forecasts for ethane shows that costs are tracking natural gas now, but as planned export and chemical utilization projects on the U.S. Gulf Coast and East Coast are completed later in this decade, we expect ethane price to return to its traditional pricing that generally tracks crude indices. Ethane spot prices on U.S. mainland are at a discount of $0.50 or more to Henry Hub natural gas spot price, which has been below $3.00/MMBTU. But just as LNG delivered price is much higher at $12-14 MMBTU or more, actual proposals for ethane delivered to Caribbean islands have shown pricing at more than $10/MMBTU, indexed to natural gas at Henry Hub. This would not necessarily beat LNG in the long term, but may be more attractive than diesel.

So there may be a short term price benefit in using propane or ethane, but to take advantage of this would require significant investment in fuel-specific handling and storage facilities as well as conversion of power plants to burn these fuels. Whether such investments would pay off in the longer term is questionable compared to pursuit of LNG options.

For these reasons, Siemens proposed as a reasonable IRP position that IRP costs be based on continued use of distillate oil or diesel where HFO and LNG are not used. Other fuels such as propane and ethane may have some potential for fuel cost savings. However, in the long term the savings would not likely be significant for the IRP results.

5.5.4 Light Distillate Oil, Diesel

Light distillate oil is purchased, delivered to and stored at most of the PREPA generation sites. This includes the four main power plant sites at San Juan, Palo Seco, Aguirre and Costa Sur as well as sites for peaking units including Cambalache, Mayagüez and the 18 other small GT peaking units at various locations.

It is common that Ultra Low Sulfur Diesel is supplied for fuel purchased under the distillate fuel oil specification. Distillate is specified with Sulfur level of 0.05 percent and ultra-low sulfur diesel (ULSD) has a maximum sulfur content of 15 ppm.

Distillate storage and forwarding at San Juan site supports distillate firing of the large (200 MW each) San Juan 5&6 combined cycle units. Palo Seco has storage and forwarding systems supplying several peaking GTs firing distillate. Distillate storage and forwarding at Aguirre serves the existing Aguirre Combined Cycle 1&2 blocks at 276 MW each.

If large combined cycle units are built at Palo Seco and Aguirre in scenarios in which Natural Gas is not available at those sites, then it may be necessary to convert some HFO storage and handling systems to distillate oil, or to build new distillate infrastructure sized for the expected primary or backup fuel needs.

5.5.5 HFO/No. 6 Oil

No. 6 fuel oil is purchased, delivered to and stored at PREPA's four main power plant sites at San Juan, Palo Seco, Aguirre and Costa Sur. HFO is fired in PREPA's steam electric plant boilers with unit electrical outputs from 85 MW to 450 MW. HFO oil firing will continue at Costa Sur 5&6 in combination with natural gas at about 80 percent of natural gas and 20 percent of HFO blend to comply with MATS.

To comply with MATS, six units will be designated as Limited Use under MATS, which limits them to less than 8 percent annual heat input Capacity Factor on a 2 year average basis. So HFO must continue to be available for these units, including Costa Sur 3&4, Palo Seco 1&2, and San Juan 7&8.

The MATS compliance plan contemplates continuing to operate Palo Seco 3&4 and San Juan 9&10 for several years until new generation at Palo Seco can be installed to allow retirement or limited use operation of these units. After the retirements of units at Palo Seco and San Juan, it may be possible to convert some of the HFO storage to distillate storage to support any new generation located at these two sites. Even if a gas supply to the North is developed, this will take a number of years and power units also would need distillate oil as backup in case of natural gas/LNG supply interruptions.

The plan for Aguirre 1&2 MATS compliance is to operate on HFO until natural gas is available from AOGP. The units will be converted to dual fuel (HFO/natural gas) firing in 2016-2017, but will continue to operate on HFO until natural gas from AOGP is available at the start of FY2018.

In case AOGP does not proceed, Aguirre 1&2 would continue to operate on HFO until several new distillate fired combined cycle generation units could be built to replace Aguirre 1&2 capacity. HFO storage may be converted to distillate storage to support such replacement units, or as backup to natural gas fired units that may be built in the longer term for efficiency upgrades if AOGP is implemented.

There is a possibility of using large reciprocating engine generators at one or more sites to enhance system-wide load following capability. Such engines can be purchased with HFO firing capability[38], which would provide a fuel price advantage over diesel or natural gas. Several comments about reciprocating engine fuel options:

- It is not clear whether reciprocating engines on HFO could meet USEPA emission standards, or whether they would be a practical and economic choice with the emission controls that might be required to meet such standards.
- From a transmission point of view, it may be desirable to locate reciprocating engines at certain existing peaking unit sites (Cambalache, Mayagüez and distributed 21 MW GTs). But if there is no existing HFO infrastructure at such sites, it probably would not be practical and cost-effective to develop it. So such units likely would be located at the main power generation sites that already use HFO.
- PREPA HFO specifications for boiler fuel would need to be checked for compatibility with reciprocating engines. Certain parameters such as fuel density, viscosity and Calculated Carbon Aromaticity Index (CCAI), an indicator of HFO ignition quality, may be different for engine fuel. This could require developing separate delivery, storage and forwarding systems for engine HFO, or dedicating some existing systems and converting them to segregated storage of HFO meeting a specification tailored to engines.

[38] For example, Wärtsila DF models can burn HFO, diesel or NG; GD models can burn HFO, diesel, NG or ethane; and SG models cannot burn HFO or diesel but can burn NG, propane or ethane. So the final selection of the model will depend on available fuels, fuel pricing and ability to obtain air emission permits for various fuels.

Section

6

Four Futures

Based on extensive discussions with PREPA regarding the load, generation, transmission, operation, environmental compliance, RPS, energy efficiency, distributed generation (DG), and current and future financial situation, the Siemens team proposes four future scenarios (Futures), three Supply Portfolios, and evaluation metrics for the IRP planning horizon of fiscal year 2016 to 2035 (July 1, 2015 – June 30, 2035).

A Future is defined as a set of internally consistent assumptions that describe the future external environment in which PREPA might be expected to operate its Supply Portfolios. These elements include, but are not limited to, gas availability in the South and North, delivered fuel prices, capital availability constraints, load, RPS, DG penetration, energy efficiency, and other parameters that are outside of PREPA's control but will impact PREPA dispatch, operation and costs. Siemens proposes four Futures with varying assumptions across eight key drivers. Table 6-1 summarizes the proposed four Futures.

Table 6-1: Four Futures

	Future 1	Future 2	Future 3	Future 4
AOGP	yes	no	yes	yes
Gas to North	no	no	yes	no
Fuel Prices	Costa Sur, Eco and Aguirre gas prices converge	Price deferential maintained	Costa Sur, Eco and Aguirre gas prices converge	Costa Sur, Eco and Aguirre gas prices converge
Capital Costs	Limited capital	Limited capital	Increased capital	Limited capital
Load Gross	PREPA forecast	PREPA forecast	PREPA forecast	PREPA reduced forecast
RPS	10% 2020 12% 2025 15% 2035	10% 2020 12% 2025 15% 2035	10% 2020 12% 2025 15% 2035	Same installations as other Futures / Results differ due to reduced sales
Distributed Generation	PREPA forecast 350 MW by 2035	PREPA forecast 350 MW by 2035	PREPA forecast 350 MW by 2035	Increased to 600 MW by 2035
Government Energy Efficiency (EE)	80% of mandate achieved	80% of mandate achieved	80% of mandate achieved	80% of mandate achieved

Source: Siemens PTI, Pace Global

6.1 Future 1: Base Case with AOGP

Future 1, Base Case with AOGP, is designed to represent the most likely set of assumptions of PREPA's future. Key assumptions of the Future 1, Base Case with AOGP, include the following:

6.1.1 AOGP

Future 1 assumes that AOGP will come online on July 1, 2017. AOGP will supply gas needs for Aguirre 1&2 combined cycle units up to 35 percent capacity factor and Aguirre 1&2 steam units up to 55 percent capacity factor, according to the limits set in the current Aguirre Power Complex Conversion Project air permit application. This equates to approximately 40,470 MMscf per year for Aguirre 1&2 steam units and 16,250 MMscf per year for Aguirre combined cycle units.

6.1.2 Gas to the North

Future 1 assumes that no gas will be available in the North.

6.1.3 Fuel Prices and Availability

Delivered natural gas at Costa Sur is currently priced on a formula linked to 0.5 percent sulfur content No. 6 fuel oil prices plus a transportation adder. The oil-linked pricing formula reflects the fact that No. 6 fuel oil prices represent the opportunity costs of natural gas to PREPA.

EcoEléctrica spot price applies to the production above a 75 percent capacity factor and is also priced according to an undisclosed formula that appears to be linked to PREPA's avoided costs of generating in other units in the system.

Siemens assumes that the delivered gas pricing at Costa Sur, Aguirre and EcoEléctrica plants will converge due to expected gas-on-gas competition after AOGP comes online in 2017. As a result, the delivered gas prices to Costa Sur and EcoEléctrica spot prices will likely be lowered from current levels after 2017 and converge to similar prices at the three plants. Volume III of the IRP report provides detailed discussions of the fuel prices assumptions.

Gas supply to Costa Sur is assumed limited to the current contractual levels that necessitate burning a combination of HFO and natural gas with a 20 percent HFO and 80 percent natural gas at Costa Sur ST 5 and 25 percent HFO and 75 percent natural gas at Costa Sur ST 6. When the units are repowered in Portfolio 1 or replaced by new combined cycle units in Portfolio 2 or 3, it is assumed that EcoEléctrica will permit one of the two standby regasifiers and be able to increase the volumes available for Costa Sur as required to operate using 100 percent with natural gas for the new combined cycles or 90 percent natural gas and 10 percent HFO for both repowered or replaced units.

6.1.4 Capital Costs

The capital availability and costs are critical factors for the IRP planning. Future 1 assumes that PREPA would have limited access to capital for taking on new projects and making improvements to the generation system[39]. In Future 1, PREPA will limit the priority of capital spending in the first 10 years (FY 2016 - 2025) to MATS compliance, integration of renewable (to avoid large curtailment), and system reliability.

Based on discussions with PREPA and its advisors, Siemens assumes that PREPA will recover from the current financial conditions and have improved access to capital during the second 10 years (FY 2026 - 2035) forecast period across all four Futures. In this later period, investments that are justified based on economics are included, i.e., the

[39] Capital investments on transmission are mandated by reliability considerations and must be in place before the MATS non-compliant units in the north can be retired.

increase in generation fleet efficiency, as well as the fuel and operating costs savings compensate capital cost of a new plant.

6.1.5 Gross Load

In Future 1, Siemens assumes PREPA's official forecast of gross load, which has projected minimal growth rates. Volume III of the IRP report provides detailed discussions of load forecast.

6.1.6 RPS

Puerto Rico's RPS was established in Act 82-2010 and amended in Act 57-2014. The RPS requires 12 percent of PREPA's retail sales to be supplied by renewable generating sources by 2015, with additional requirements of 15 percent by 2020 and 20 percent by 2035. The level of renewable generation added to the system impacts the level and required flexibility of conventional generating resources. The RPS requirements and associated intermittent renewable energy are projected to cause significant operating challenges to PREPA's generation, transmission, and distribution assets. Capital investments in conventional generating resources will need to be considered in order to fully integrate the new renewable generation into PREPA's system.

In evaluating the tradeoffs, priorities and objectives of PREPA under the constraints of very challenging financial conditions, Siemens and PREPA has set reduced and delayed milestones RPS goals as follows: 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. As PREPA's fleet is replaced by new flexible generation that can start daily, ramp faster and have reduced minimum regulating limits, the percentage of renewable generation increases over time.

The reduced and delayed RPS goals were set up considering the capability of PREPA's fleet to accommodate renewable generation without unacceptable levels of renewable curtailment[40]. Specifically, this reduced target is determined by: a) the need to keep thermal generation online during daytime so it can supply the night peak, b) thermal generation minimum regulating limits, and c) thermal steam units minimum run times once they are started (typically 720 hours). Even with reduced RPS goals, significant levels of curtailment are expected unless the steam units in PREPA fleet are replaced by flexible combined cycles.

To fully evaluate the tradeoffs, a full RPS compliance sensitivity case was evaluated to verify if the 20 percent of renewable generation can be accommodated by 2035 with a modernized fleet. See Section 9.1 for detailed analysis of this sensitivity case. Higher goals before modernization of the fleet would have resulted in unacceptable and unrealistic levels of renewable curtailment.

A total capacity of 1,056 MW (43 projects) are included in the IRP model. This includes six existing renewable projects of approximately 173 MW capacity[41] and 37 future renewable projects with a total capacity of 883 MW. Among the 37 renewable contracts

[40] As indicated earlier, curtailment is energy that the renewable projects could have produced but cannot be safely accepted in the system, due to technical limitations of the generating fleet. This energy has to be paid; using estimates of the energy curtailed as per current contractual conditions and hence has a cost.

[41] Including Horizon (10 MW) in pre-operation

to be executed, 19 projects for a total capacity of 441 MW have reasonable probability of moving forward, and the remaining 18 projects have significant uncertainties. These future renewable projects require long-term offtake contracts from PREPA. Given PREPA's current credit rating and financial conditions, the timing of these utility-scale renewable projects is highly uncertain. Section 4.2 provides details on the renewable projects considered for the various RPS levels.

6.1.7 Distributed Generation

Distributed generation penetration is based on PREPA's forecast. Section 4.3 provides details of the assumptions for distributed generation.

6.1.8 Government Energy Efficiency

Government Energy Efficiency, as mandated by Act 57-2014, to reduce the consumption at government institutions with respect of a benchmark, is based on PREPA's forecast that only 80 percent of the mandate will be achieved.

Generally speaking, there was little incentive for government agencies to manage and control their energy consumption, in particular those belonging to the municipalities. Even after Act 57 being in force for a full year, PREPA has not seen the required reduction in consumption. In addition, most Energy Efficiency efforts require capital spending, which is in extremely short supply in Puerto Rico's current financial difficulties. The 80 percent estimate for compliance is an extremely optimistic view on government compliance. In spite of this, PREPA's system peak is at night, so any energy reduction by these accounts would typically affect the day peak and energy consumption.

6.2 Future 2: Base Case without AOGP

Future 2, Base Case without AOGP, is designed to assess the impact of AOGP on PREPA's resource plans. Future 2 shares the same assumptions as Future 1, except that AOGP does not come online and no additional natural gas is available outside of what is available today. As a result, this will likely set the EcoEléctrica spot prices at the current pricing structure due to lack of competition, and could affect the natural gas pricing at Costa Sur.

However, under this Future, it will become a priority for PREPA to increase the gas supplies to Costa Sur. It is assumed that an agreement will be reached by July 2017 whereby EcoEléctrica will permit one of the two standby re-gasifiers and be able to increase the volumes available to Costa Sur by July 2020 allowing a mix of 90 percent natural gas and 10 percent HFO.

6.3 Future 3: Base Case with AOGP and Added Investment

Future 3, Base Case with AOGP and Added Investment, is designed to evaluate a potential future state similar to Future 1, with the exception of the following two key assumptions.

6.3.1 Gas to North

PREPA has previously evaluated the viability of several alternatives to enable the delivery of natural gas to the San Juan metro area for power generation. Gas to the

North presents an appealing proposition of enabling PREPA to build new or convert existing generation close to the demand centers and reduce the level of dependence on the South-to-North electric transmission system. While gas to the North could potentially be achieved via LNG infrastructure in the North or a South-to-North gas pipeline, the feasibility of either option is yet to be evaluated.

Future 3 explores the impact of a gas infrastructure project resulting in the delivery of natural gas to the San Juan metro area by July 1, 2022.

Note that Future 3 does not result in savings in transmission investments as these must be in place by the time the non-MATS compliant units in the North are retired or declared limited use and by that time the investments in additional generation at San Juan are not expected to be in place. Moreover the added flexibility to attend an eventual load growth (or reduced decline from 2014 values) makes it unadvisable to postpone these investments (see Volume II).

6.3.2 Capital Costs

Future 3 assumes that PREPA is able to resolve the current financial difficulty sooner, and have more access to capital than the other three Futures. Under Future 3, PREPA will have improved access to capital to build infrastructure to bring gas to the North, upgrade and add new generation units to improve efficiency. For comparison, Portfolios in Future 3 incur approximately $1 billion more capital costs than in Future 2.

6.4 Future 4: Base Case with AOGP and Declining Load Served

Future 4, Base Case with AOGP and more distributed generation and slightly increased decline in load (with respect of the base forecast), is designed to evaluate a potential future state similar to Future 1, with the exception of a lower 'net' load served.

6.4.1 Net Load Impacts

Future 4 assumes the lowest and most recent PREPA's official gross load forecast, which shows a slight acceleration of the load decline. However the largest impact in reduction of the load served comes from an almost doubling of the distributed generation installed by PREPA's customers.

6.4.2 RPS

Future 4 assumes same level of renewable capacity as the other three Futures, which leads to slightly improved RPS percentages due to reduced net sales in this Future.

Section

7

Three Supply Portfolios

A Supply Portfolio is the set of generation resources that PREPA can deploy to meet customer demand, environmental compliance, and system reliability requirements. The performance of each Supply Portfolio will be evaluated based on a set of financial and non-financial metrics. The recommended Supply Portfolio is the one that performs the best in terms of the financial, reliability and environmental metrics across the Futures.

Siemens proposes three Supply Portfolios to evaluate the merits of focusing on repowering existing generation units, new builds with smaller combined cycle units, or new builds with larger combined cycle units. Given the myriad of considerations and tradeoffs to be evaluated from the perspectives of generation, system operation, capital costs, fuel and operation costs, and environmental compliance, Siemens believes that a systematic approach of evaluating three distinctively different Supply Portfolios will help to establish clarity for the planning approaches with quantifiable metrics to support the recommended Supply Portfolio.

In the IRP, each portfolio is evaluated across all Futures. To the extent possible, unique combinations of portfolios and scenarios must be avoided as it becomes difficult to objectively assess the performance of the Supply Portfolio in terms of costs and risks. The Supply Portfolios have been designed from a point of view of minimizing capital investments, maximizing fuel efficiency, or introducing more system flexibility.

- Supply Portfolio 1 focuses on minimizing investments by pursuing repowering initiatives and utilizing existing equipment to the extent possible.
- Supply Portfolio 2 builds smaller new units in the form of 1x1 combined cycles with the goal of designing a flexible generation system that can better follow the net load profile[42].
- Supply Portfolio 3 focuses on large combined cycle builds. This Supply Portfolio is potentially the most efficient but may not be as flexible as Supply Portfolio 2.

Based on the transmission studies carried out by Siemens PTI (the PREPA Reliability Study), it was identified that the PREPA system required additional generation in the North and in particular in the Bayamón and San Juan areas, in addition to the San Juan CC 5&6, once San Juan 9&10 and Palo Seco 3&4 are retired or relegated to limited use. Preliminary analysis, which was later confirmed, identified that when a number of investments in transmission are in place, the generation at San Juan 9&10 and Palo Seco 3&4 could be replaced by 210 MW new generation at Palo Seco to maintain the reliability of the PREPA system. The need to provide this minimum generation by 2020 became a common factor under all portfolios.

[42] Net Load = Gross Load – Renewable Generation

For the most part, the Portfolios are the same across each Future in terms of size and composition. However, the location of the new builds may vary based on availability of natural gas on the island.

Table 7-1 outlines the characteristics and technical configurations of the three proposed Supply Portfolios.

Table 7-1: Proposed Supply Portfolios Characteristics and Technical Configurations

Supply Portfolios	Characteristics	Technical Configurations
1	Small New Builds and Repowering	Aero/ Small CC or Reciprocating Engines at Palo Seco; Heavily Fired Combined Cycle (HFCC) Repowering
2	New Builds of Smaller CC Units	Aero/ Small CC or Reciprocating Engines at Palo Seco; Smaller 1X1 CC
3	New Builds of Larger CC Units	Smaller 1x1 CC at Palo Seco; Larger 1x1 CC

Source: Siemens PTI, Pace Global

7.1 Portfolio Development Process

Siemens established the proposed resources and timing using expert opinion and professional judgment to weigh numerous important criteria such as:

- The potential for encountering certain future conditions as specified by PREPA for the Four Futures, such as availability and location of natural gas supplies, renewable penetration, growth in distributed generation, etc. It should be noted that the timing and location of generation projects for each Portfolio were adapted based on the Future conditions. For example, when natural gas is available only in the South, more generation is located there to save fuel cost vs. distillate firing. But when gas is available in the North, some generation is located there to decrease dependence on transmission so that the overall system is more robust in responding to severe emergency events such as hurricanes.
- Sequencing of projects to achieve realistic use of PREPA's management and engineering resources and suppliers' and contractor's resources to furnish materials and construction services. While permitting and development could overlap to some extent, Siemens tried to limit major generation project implementation to one or two at any given time.
- Compliance with environmental mandates such as MATS as soon as reasonably possible while maintaining reliability of power supply.
- Necessity to complete certain transmission upgrades before older generation could be taken out of service. A large amount of generation at San Juan and Palo Seco was retired for MATS compliance and replaced with only 200-300 MW of new generation at Palo Seco. The transmission allowed the northern loads to be served reliably by generation in the South.
- Anticipated project durations based on industry experience and accounting for local construction challenges such as importing materials, obtaining sufficient, qualified construction labor to meet the required staffing plans, etc.

- Practical constraints on capital availability that limit how soon all desirable projects could be completed.
- Capacity needs based on forecasted sustained and peak loads as they vary over the analysis period.
- The need to maximize system flexibility as early as practical to accommodate ramping of renewables and to minimize renewables curtailment, while considering other constraints on timing of implementing new generation projects needed to provide such flexibility.
- Cost benefits from maximizing long term fuel efficiency and using the most cost-effective fuels.

After establishing the generation projects' timing for each Portfolio, the overall costs and reliability of the entire system then was confirmed with the PROMOD runs. This provided feedback on how successful each Portfolio was in meeting the criteria discussed above and in achieving PREPA's goals regarding investment, operating costs, renewable penetration and compliance with Puerto Rico and U.S. government laws, regulation and environmental requirements.

Detailed load and resource balance for each portfolio are presented in Appendix E.

7.2 Supply Portfolio 1 - Small New Build and Repowering

Supply Portfolio 1 focuses on small new builds and repowering across all three Futures in which gas is available in the South (Future 1 and 4) or in both the South and the North (Future 3)[43]. Key portfolio decision components of Supply Portfolio 1 include the following and are summarized in Table 7-2. After these portfolio changes, the total capacity of PREPA's system will be lower than the current level because it is not a one for one replacement on a MW capacity basis.

- Declare limited use or retire six units with a combined capacity of 540 MW including Costa Sur 3&4, Palo Seco 1&2 steam units, San Juan 7&8 steam units by December 31, 2020.
- Palo Seco 3&4 steam units (with a total capacity of 432 MW) and San Juan 9&10 steam units (with a total capacity of 200 MW) continues operation burning No. 6 fuel oil through December 31, 2020, when they will be retired or designated to limited use.
- Aguirre 1&2 steam units and Aguirre 1&2 CC units will have fuel conversion by July 1, 2017 when AOGP comes online in Future 1, 3 and 4.
- In all Futures, three SCC-800 combined cycle units will be installed at Palo Seco site by December 31, 2020.
    - In Future 3, the new generation at Palo Seco site will burn diesel initially and switch to gas when gas to the North is available by July 1, 2022.
    - In Future 1 and 4, the new generation at Palo Seco site will burn diesel.

[43] HFCC repowering without natural gas would require continued firing of the Aguirre boilers on HFO for an indefinite time period in noncompliance with MATS regulations. Thus, Portfolio 1 is not feasible in Future 2 without natural gas at Aguirre, and the combination Future 2 and Portfolio 1 is not evaluated.

- Aguirre 1&2 CC units will have gas turbine replacement or repowering by the end of FY 2021 and 2022, respectively, with gas as the primary fuel for Future 1, 3 and 4.
- Aguirre 1&2 steam units:
    - Aguirre 1&2 steam units will have HFCC repowering by the end of FY 2026 and 2027, respectively, in Future 1 and 4; and by the end of FY 2023 and 2024 in Future 3.
    - These repowered units will have gas as the primary fuel in Future 1, 3 and 4.
    - No repowering is considered for Future 2 as these units will have to be retired due to MATS compliance; no MATS compliance is considered feasible without gas at Aguirre. This fact makes the combination of Portfolio 1 and Future 2 unrealistic.
- Costa Sur 5&6 steam units:
    - Costa Sur 5&6 steam units will have HFCC repowering with gas as the primary fuel by the end of FY 2028 and 2029, respectively, in Future 1 and 4.
    - Costa Sur 5&6 steam units will have HFCC repowering with gas as the primary fuel by the end of FY 2025 and 2026, respectively, in Future 3.
- Transmission reinforcements:
    - As we are considering the repowering of both Aguirre 1&2 and Costa Sur 5&6 and have limited new generation in the North in Supply Portfolio 1, the transmission will need to be reinforced under all three Futures.
    - The transmission reinforcements are discussed in Volume II of the IRP report.

Table 7-2: Supply Portfolio 1 - Small New Build and Repowering

Supply Portfolio 1 - Small New Build and Repowering	Future 1	Future 3	Future 4
AOGP Online	Yes, by July 1, 2017	Yes, by July 1, 2017	Yes, by July 1, 2017
North Gas Supply	No	Yes, by July 1, 2022	No
2020 Transmission Upgrades	Yes	Yes	Yes
San Juan 9 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020	Retire by 12/31/2020
San Juan 10 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020	Retire by 12/31/2020
Palo Seco 3 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Palo Seco 4 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Aguirre 1 Steam Unit Gas Fuel Conversion	Yes, by July 1, 2017	Yes, by July 1, 2017	Yes, by July 1, 2017
Aguirre 2 Steam Unit Gas Fuel Conversion	Yes, by July 1, 2017	Yes, by July 1, 2017	Yes, by July 1, 2017
Aguirre 1 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, by July 1, 2017	Yes, by July 1, 2017	Yes, by July 1, 2017
Aguirre 2 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, by July 1, 2017	Yes, by July 1, 2017	Yes, by July 1, 2017
New Generation at Palo Seco Site	Small/Aero CC (Diesel), 12/31/2020	Small/Aero CC (Diesel), 12/31/2020	Small/Aero CC (Diesel), 12/31/2020
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	NG, 2021	NG, 2021	NG, 2021
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	NG, 2022	NG, 2022	NG, 2022
Aguirre 1 Steam Unit Replacement	HFCC Repower (NG), 2026	HFCC Repower (NG), 2023	HFCC Repower (NG), 2026
Aguirre 2 Steam Unit Replacement	HFCC Repower (NG), 2027	HFCC Repower (NG), 2024	HFCC Repower (NG), 2027
Costa Sur 5 Steam Unit Replacement	HFCC Repower (NG), 2028	HFCC Repower (NG), 2025	HFCC Repower (NG), 2028
Costa Sur 6 Steam Unit Replacement	HFCC Repower (NG), 2029	HFCC Repower (NG), 2026	HFCC Repower (NG), 2029

Note:

(1) Dates are by the end of the fiscal year unless otherwise noted.
(2) In Future 3, the new generation at Palo Seco site will have dual fuel capability, burn diesel before gas to the North is available by July 1, 2022.
(3) Details of HFCC repowering and small CC are provided in Section 3.2.9 of this report.

Source: Siemens PTI, Pace Global

7.3 Supply Portfolio 2 - New Builds of Smaller CC Units

Supply Portfolio 2 focuses on new builds of smaller combined cycle units across all four Futures. Key portfolio decision components of Supply Portfolio 2 include the following and are summarized in Table 7-3. After these portfolio changes, the total capacity of PREPA's system will be lower than the current level because it is not a one for one replacement on a MW capacity basis.

- Declare limited use or retire six units with a combined capacity of 540 MW including Costa Sur 3&4, Palo Seco 1&2 steam units, San Juan 7&8 steam units by December 31, 2020.
- Palo Seco 3&4 steam units (with a total capacity of 432 MW) and San Juan 9&10 steam units (with a total capacity of 200 MW) continues operation burning No. 6 fuel oil through December 31, 2020, when they will be retired or designated limited use.
- Aguirre 1&2 steam units and Aguirre 1&2 CC units will have fuel conversion by July 1, 2017 when AOGP comes online in Future 1, 3 and 4.
- In all four Futures, three SCC-800 combined cycle units will be installed at Palo Seco site by December 31, 2020.
    - In Future 3, the new generation at Palo Seco site will burn diesel initially and switch to gas when gas to the North is available by July 1, 2022.
    - In Future 1, 2 and 4, the new generation at Palo Seco site will burn diesel.
- Aguirre 1&2 CC units:
    - In Future 1, 3 and 4, Aguirre 1&2 CC units will have turbine replacement by the end of FY 2021 and 2022 separately, with gas as the primary fuel.
    - In Future 2, Aguirre 1&2 CC units will have turbine replacement by the end of FY 2019 and 2020 separately with diesel as the primary fuel.

- Aguirre 1&2 steam units:
  - In Future 1 and 4, Aguirre 1&2 steam units will be replaced with three small (F Class) 1x1 combined cycle units at Aguirre site by the end of FY 2026, 2027 and 2028 respectively.
  - In Future 2, Aguirre 1&2 steam units will be replaced with one small (F Class) 1x1 combined cycle unit at San Juan site by December 31, 2020 and two small (F Class) 1x1 combined cycle units at Aguirre sites by December 31, 2021 and 2022 respectively.
  - In Future 3, Aguirre 1&2 steam units will be replaced with one small (F Class) 1x1 combined cycle unit at San Juan site by the end of FY 2023, and two small (F Class) 1x1 combined cycle units at Aguirre sites by the end of 2024 and 2025, respectively.
  - All three new CC units will have natural gas as the primary fuel in Future 1, 3 and 4 and will have diesel as the primary fuel in Future 2.
- Costa Sur 5&6 steam units:
  - In Future 1 and 4, Costa Sur 5&6 steam units will be replaced with two small (F Class) 1x1 combined cycle units at the Costa Sur site by the end of FY 2031 and 2032.
  - In Future 2 and 3, Costa Sur 5&6 steam units will be replaced with two small (F Class) 1x1 combined cycle units at the Costa Sur site by the end of FY 2028 and 2029.
  - New 1x1 CC units will have natural gas as the primary fuel in all four Futures.
- Transmission reinforcements:
  - In Future 2 and 3, one F Class 1x1 combined cycle unit (358 MW) will be installed at San Juan. This capacity combined with the Palo Seco combined cycles of 210 MW capacity results in approximately 568 MW in the North.
  - This increased capacity reduces the reliance on transmission and the need for the proposed reinforcements discussed later in this document. However this benefit is only realized for Future 2, where the entire new generation in the North will be online by December 31, 2020 at the time of the retirement of San Juan 9&10, thus under this scenario the investments could be delayed. However as shown in Volume II this is not recommended.
  - In Future 3, this additional capacity will only come online by FY 2023, two years after PSSP 3&4 and SJSP 9&10 retirements, thus necessitating the use of transmission as only the new Palo Seco CC will be in service and the delaying of transmission investments is not feasible.
  - Future 1 and Future 4 have limited generation in the North and the transmission investments are necessary.

Table 7-3: Supply Portfolio 2 - New Builds of Smaller CC Units

Supply Portfolio 2 - New Builds of Smaller CC Units	Future 1	Future 2
AOGP Online	Yes, by July 1, 2017	No
North Gas Supply	No	No
2020 Transmission Upgrades	Yes	Yes
San Juan 9 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020
San Juan 10 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020
Palo Seco 3 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Palo Seco 4 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Aguirre 1 Steam Unit Gas Fuel Conversion	Yes, by July 1, 2017	No
Aguirre 2 Steam Unit Gas Fuel Conversion	Yes, by July 1, 2017	No
Aguirre 1 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, by July 1, 2017	No
Aguirre 2 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, by July 1, 2017	No
New Generation at Palo Seco Site	Small/Aero CC (Diesel), 12/31/2020	Small/Aero CC (Diesel), 12/31/2020
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	NG, 2021	Diesel, 12/31/2019
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	NG, 2022	Diesel, 12/31/2020
Aguirre 1&2 Steam Units Replacement, Train 1	F Class 1x1 CC (NG, Aguirre site), 2026	F Class 1x1 CC (Diesel, San Juan site), 12/31/2020
Aguirre 1&2 Steam Units Replacement, Train 2	F Class 1x1 CC (NG, Aguirre site), 2027	F Class 1x1 CC (Diesel, Aguirre site), 12/31/2021
Aguirre 1&2 Steam Units Replacement, Train 3	F Class 1x1 CC (NG, Aguirre site), 2028	F Class 1x1 CC (Diesel, Aguirre site), 12/31/2022
Costa Sur 5&6 Steam Units Replacement, Train 1	F Class 1x1 CC (NG, Costa Sur site), 2031	F Class 1x1 CC (Eco NG, Costa Sur site), 2028
Costa Sur 5&6 Steam Units Replacement, Train 2	F Class 1x1 CC (NG, Costa Sur site), 2032	F Class 1x1 CC (Eco NG, Costa Sur site), 2029
Costa Sur 5&6 Steam Units Replacement, Train 3	Not Required	Not Required

Supply Portfolio 2 - New Builds of Smaller CC Units	Future 3	Future 4
AOGP Online	Yes, by July 1, 2017	Yes, by July 1, 2017
North Gas Supply	Yes, by July 1, 2022	No
2020 Transmission Upgrades	Yes	Yes
San Juan 9 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020
San Juan 10 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020
Palo Seco 3 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Palo Seco 4 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Aguirre 1 Steam Unit Gas Fuel Conversion	Yes, by July 1, 2017	Yes, by July 1, 2017
Aguirre 2 Steam Unit Gas Fuel Conversion	Yes, by July 1, 2017	Yes, by July 1, 2017
Aguirre 1 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, by July 1, 2017	Yes, by July 1, 2017
Aguirre 2 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, by July 1, 2017	Yes, by July 1, 2017
New Generation at Palo Seco Site	Small/Aero CC (Diesel), 12/31/2020	Small/Aero CC (Diesel), 12/31/2020
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	NG, 2021	NG, 2021
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	NG, 2022	NG, 2022
Aguirre 1&2 Steam Units Replacement, Train 1	F Class 1x1 CC (NG, San Juan site), 2023	F Class 1x1 CC (NG, Aguirre site), 2026
Aguirre 1&2 Steam Units Replacement, Train 2	F Class 1x1 CC (NG, Aguirre site), 2024	F Class 1x1 CC (NG, Aguirre site), 2027
Aguirre 1&2 Steam Units Replacement, Train 3	F Class 1x1 CC (NG, Aguirre site), 2025	F Class 1x1 CC (NG, Aguirre site), 2028
Costa Sur 5&6 Steam Units Replacement, Train 1	F Class 1x1 CC (NG, Costa Sur site), 2028	F Class 1x1 CC (NG, Costa Sur site), 2031
Costa Sur 5&6 Steam Units Replacement, Train 2	F Class 1x1 CC (NG, Costa Sur site), 2029	F Class 1x1 CC (NG, Costa Sur site), 2032
Costa Sur 5&6 Steam Units Replacement, Train 3	Not Required	Not Required

Note:

(1) Dates are by the end of the fiscal year unless otherwise noted.

(2) Details of Aero, small CC, reciprocating engine and F Class generating units are provided in Section 3.2.9 of this report.

Source: Siemens PTI, Pace Global

7.4 Supply Portfolio 3 - New Builds of Larger CC Units

Supply Portfolio 3 focuses on new builds of larger combined cycle units across all four Futures. Key portfolio decision components of Supply Portfolio 3 include the following and are summarized in Table 7-4. After these portfolio changes, the total capacity of PREPA's system will be lower than the current level because it is not a one for one replacement on a MW capacity basis.

- Declare limited use or retire six units with a combined capacity of 540 MW including Costa Sur 3&4, Palo Seco 1&2 steam units, San Juan 7&8 steam units by December 31, 2020.
- Palo Seco 3&4 steam units (with a total capacity of 432 MW) and San Juan 9&10 steam units (with a total capacity of 200 MW) continues operation burning No. 6 fuel oil through December 31, 2020, when they will be retired or designated to limited use.
- Aguirre 1&2 steam units and Aguirre 1&2 CC units will have fuel conversion by July 1, 2017 when AOGP comes online in Future 1, 3 and 4.
- In all four Futures, one F Class 1x1 CC unit will be installed at Palo Seco site by December 31, 2020.
    - In Future 3, the new generation at Palo Seco site will burn diesel initially and switch to gas when gas to the North is available by July 1, 2022.
    - In Future 1, 2 and 4, the new generation at Palo Seco site will burn diesel.
- Aguirre 1&2 CC units:
    - In Future 1, 3 and 4, Aguirre 1&2 CC units will have turbine replacement or repowering by the end of FY 2021 and 2022 separately, with gas as the primary fuel.
    - In Future 2, Aguirre 1&2 CC units will have turbine replacement or repowering by December 31, 2019 and 2020, with diesel as the primary fuel.
- Aguirre 1&2 steam units:
    - Aguirre 1&2 steam units will be replaced with two large H Class 1x1 combined cycles at Aguirre site by the end of FY 2026 and 2027, respectively, in Future 1 and 4.
    - Aguirre 1&2 steam units will be replaced with one large H Class 1x1 combined cycle unit at San Juan site by December 31, 2020, and one H Class 1x1 combined cycle units at Aguirre site by December 31, 2021 in Future 2.
    - Aguirre 1&2 steam units will be replaced with one large H Class 1x1 combined cycle unit at San Juan site by the end of FY 2023, and one H Class 1x1 combined cycle units at Aguirre site by the end of 2024 in Future 3.
    - All new combined cycle units at Aguirre will have natural gas as the primary fuel in Future 1, 3 and 4, and will have diesel as the primary fuel in Future 2. The combined cycle at San Juan will have diesel as the primary fuel under all Futures with the exception of Future 3.

- Costa Sur 5&6 steam units:
    - Costa Sur 5&6 steam units will be replaced with two large H Class 1x1 combined cycle units at the Costa Sur site by the end of FY 2030 and 2031 in Future 1 and 4.
    - Costa Sur 5&6 steam units will be replaced with two large H Class 1x1 combined cycle units at the Costa Sur site by the end of FY 2027 and 2028 in Future 2 and 3.
    - New H Class 1x1 combined cycle units will have natural gas as the primary fuel in all four Futures.
- Transmission reinforcements:
    - Only in Future 2 that has one F Class 1x1 combined cycle (360 MW) installed at San Juan and another at Palo Seco by December 31 2020, will have substantial capacity in the North of the island by the retirement of Palo Seco 3&4 and San Juan 9&10 on that date, thus under this scenario the transmission investments could be delayed. However as shown in Volume II this is not recommended.
    - In Future 3, the investments at San Juan come too late to avoid the necessity of the reinforcements (2023) and Future 1 and Future 4 have limited generation in the North and the transmission investments are necessary.

Table 7-4: Supply Portfolio 3 - New Builds of Larger CC Units

Supply Portfolio 3 - New Builds of Larger CC Units	Future 1	Future 2
AOGP Online	Yes, by July 1, 2017	No
North Gas Supply	No	No
2020 Transmission Upgrades	Yes	Yes
San Juan 9 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020
San Juan 10 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020
Palo Seco 3 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Palo Seco 4 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Aguirre 1 Steam Unit Gas Fuel Conversion	Yes, 2017	No
Aguirre 2 Steam Unit Gas Fuel Conversion	Yes, 2017	No
Aguirre 1 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, 2017	No
Aguirre 2 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, 2017	No
New Generation at Palo Seco Site	F Class 1x1 CC (Diesel), 12/31/2020	F Class 1x1 CC (Diesel), 12/31/2020
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	NG, 6/30/2021	Diesel, 12/31/2019
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	NG, 6/30/2022	Diesel, 12/31/2020
Aguirre 1 Steam Unit Replacement	G/H Class 1x1 CC (NG, Aguirre site), 2026	G/H Class 1x1 CC (Diesel, San Juan site), 12/31/2020
Aguirre 2 Steam Unit Replacement	G/H Class 1x1 CC (NG, Aguirre site), 2027	G/H Class 1x1 CC (Diesel, Aguirre site), 12/31/2021
Costa Sur 5 Steam Unit Replacement	G/H Class 1x1 CC (NG, Coasta Sur site), 2030	G/H Class 1x1 CC (NG, Coasta Sur site), 2027
Costa Sur 6 Steam Unit Replacement	G/H Class 1x1 CC (NG, Costa Sur site), 2031	G/H Class 1x1 CC (NG, Coasta Sur site), 2028

Supply Portfolio 3 - New Builds of Larger CC Units	Future 3	Future 4
AOGP Online	Yes, by July 1, 2017	Yes, by July 1, 2017
North Gas Supply	Yes, by July 1, 2022	No
2020 Transmission Upgrades	Yes	Yes
San Juan 9 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020
San Juan 10 Steam Unit	Retire by 12/31/2020	Retire by 12/31/2020
Palo Seco 3 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Palo Seco 4 Steam Unit	Designated to limited use by 12/31/2020	Designated to limited use by 12/31/2020
Aguirre 1 Steam Unit Gas Fuel Conversion	Yes, 2017	Yes, 2017
Aguirre 2 Steam Unit Gas Fuel Conversion	Yes, 2017	Yes, 2017
Aguirre 1 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, 2017	Yes, 2017
Aguirre 2 CC Unit Dual Fuel Conversion (gas and diesel)	Yes, 2017	Yes, 2017
New Generation at Palo Seco Site	F Class 1x1 CC (Diesel), 12/31/2020	F Class 1x1 CC (Diesel), 12/31/2020
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	NG, 6/30/2021	NG, 6/30/2021
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	NG, 6/30/2022	NG, 6/30/2022
Aguirre 1 Steam Unit Replacement	G/H Class 1x1 CC (NG, San Juan site), 2023	G/H Class 1x1 CC (NG, Aguirre site), 2026
Aguirre 2 Steam Unit Replacement	G/H Class 1x1 CC (NG, Aguirre site), 2024	G/H Class 1x1 CC (NG, Aguirre site), 2027
Costa Sur 5 Steam Unit Replacement	G/H Class 1x1 CC (NG, Coasta Sur site), 2027	G/H Class 1x1 CC (NG, Costa Sur site), 2030
Costa Sur 6 Steam Unit Replacement	G/H Class 1x1 CC (NG, Coasta Sur site), 2028	G/H Class 1x1 CC (NG, Costa Sur site), 2031

Note:

(1) Dates are by the end of the fiscal year unless otherwise noted.
(2) Details of F, G&H Class generating units are provided in the Section 3.2.3 of this document.

Source: Siemens PTI, Pace Global

7.5 MATS Compliance

On June 29, 2015, the United States Supreme Court ruled that the EPA erred by failing to consider costs when deciding whether it was “appropriate and necessary” to regulate emissions of mercury and other hazardous air pollutants from power plants like those owned by PREPA. Although EPA considered costs when deciding how to regulate power plants (e.g., with respect to the cost of controls), the Supreme Court found that EPA was required to consider costs in the initial decision to regulate power plants. The rule at issue in the case was EPA’s Mercury and Air Toxics Standards, commonly referred to as “MATS.”

The Supreme Court did not invalidate the MATS rule and as a result all power plants continue to be legally obligated to meet the MATS standards. The Supreme Court simply returned the rule to the lower court to determine the appropriate remedy, a process that could take up to a year to complete. The lower court will either send the rule back to EPA to correct the deficiencies outlined by the Supreme Court (a remand) or invalidate the rule completely (a vacatur). Because MATS remains in effect, PREPA will continue to work to modernize its power system and achieve permanent, consistent compliance with the Clean Air Act.

PREPA has other obligations as indicated in Act 57; Section 6C-a-i: High Efficiency Generation - Within a term that shall not exceed three (3) years after July 1st, 2014, PREPA shall ensure that, at least sixty percent (60%) of the electric power generated in Puerto Rico based on fossil fuels (gas, coal, oil, and others) is “high-efficiency”, as such term is defined by the Commission. Additionally, steam electric units are subject to opacity rules and a consent decree PREPA entered into with the EPA regarding opacity.

MATS compliance strategies are the priority of the first five years of this IRP planning and are treated consistently across all three Supply Portfolios. All of PREPA’s existing 14 steam units (approximately 2,900 MW of capacity) are subject to MATS compliance mandated by EPA. Below is a breakdown of the four categories of assumptions regarding these existing steam units.

- Costa Sur 5&6 steam units with a total capacity of 820 MW are currently in compliance because they burn a blend of 80 percent natural gas and 20 percent No. 6 fuel oil for Costa Sur 5 and 75 percent natural gas and 25 percent No. 6 fuel oil for Costa Sur 6.
- Aguirre 1&2 steam units with a total capacity of 900 MW are contingent on gas from AOGP for its MATS compliance strategy.[44]
- Based on discussions with PREPA and findings from PREPA’s Electric Power System Reliability Study dated September 29, 2014, Siemens assumes that PREPA can retire or limit the use to less than eight percent of each unit nameplate heat input capacity on any consecutive 24 months block period (beginning April 16, 2015)[45] of six units with a combined capacity of 540 MW without putting the system at risk, including Costa Sur 3&4, Palo Seco 1&2 steam units, and San Juan 7&8 steam units.
- Siemens assumes that PREPA enters into a settlement agreement with EPA regarding Palo Seco 3&4 steam units (with a total capacity of 432 MW) allowing these units to continue operation burning No. 6 fuel oil through December 31, 2020, after that will be either replaced or designated as a limited use unit.
- San Juan 9&10 steam units (with a total capacity of 200 MW) will also continue to be available as per the settlement agreement. These two units will also be either retired or designated limited use by December 31, 2020.

Table 7-5 outlines the MATS compliance strategies and assumptions of each of the 14 steam units discussed above. The treatment of these units are consistent across all three Supply Portfolios and four Futures.[46] Detailed MATS compliance assessment and strategy are discussed in Volume IV Environmental Assessment of the IRP report.

[44] In Future 2, without AOGP, Aguirre 1&2 steam units must be included in a settlement allowing continued operation on HFO until replacement with distillate-fired combined cycle units by 2022 (Portfolio 2) or 2021 (Portfolio 3).

[45] Two years will be the lapse used for the calculation of the Capacity Factor. This means that if the capacity factor is 4 percent on one year then it can be 12 percent (approximately) for the next.

[46] Except for Aguirre 1&2 steam units in Future 2 that requires replacement as discussed above instead of early conversion to natural gas firing for MATS compliance.

Table 7-5: MATS Affected Units and Compliance Strategies

Steam Units	Rated Capacity (MW)	Fuel	In Compliance	Limited Use (8%)	Gas Conversion	Retirement	Comment
Costa Sur 5	410	NG/No. 6 fuel oil	X				Already complies with MATS
Costa Sur 6	410	NG/No. 6 fuel oil	X				Already complies with MATS
Aguirre 1	450	No. 6 fuel oil			100% Gas		Gas contingent on AOGP
Aguirre 2	450	No. 6 fuel oil			100% Gas		Gas contingent on AOGP
Costa Sur 3	85	No. 6 fuel oil		X			Designated as limited use unit
Costa Sur 4	85	No. 6 fuel oil		X			Designated as limited use unit
Palo Seco 1	85	No. 6 fuel oil		X			Designated as limited use unit
Palo Seco 2	85	No. 6 fuel oil		X			Designated as limited use unit
San Juan 7	100	No. 6 fuel oil		X			Designated as limited use unit
San Juan 8	100	No. 6 fuel oil		X			Designated as limited use unit
San Juan 9	100	No. 6 fuel oil				X	Retire by Dec 31, 2020
San Juan 10	100	No. 6 fuel oil				X	Retire by Dec 31, 2020
Palo Seco 3	216	No. 6 fuel oil		X			Designated as limited use unit
Palo Seco 4	216	No. 6 fuel oil		X			Designated as limited use unit
Total Capacity	**2,892**		**820**	**972**	**900**	**200**	

Note:

(1) Costa Sur 5 burns 80 percent of natural gas and 20 percent of No. 6 fuel oil and Costa Sur 6 burns 75 percent of natural gas and 25 percent of No. 6 fuel oil.

(2) Limited use units will have a heat input capacity factor or less than 8 percent measured over two years.

(3) Costa Sur 3&4, Palo Seco 1&2, San Juan 7&8 will be designated as limited use during FY 2016-2019 and will be retired by December 31, 2020.

(4) San Juan 9&10 steam units (with a total capacity of 200 MW) will be either retired or declared limited use by December 31, 2020.

(5) Palo Seco 3&4 will be replaced or designated as limited use by December 31, 2020.

Source: PREPA, Siemens PTI, Pace Global

Section
8

Supply Portfolios and Futures Results

8.1 Evaluation Metrics of Supply Portfolios

Siemens evaluated the three Supply Portfolios against four Futures across a consistent set of metrics as presented in Table 1-1.

8.1.1 Cost Metrics

Cost metrics are considered in evaluating the portfolio results, including upfront capital costs and the present value of system costs. System costs include amortized capital costs (new generation, power plant fuel conversion, transmission upgrades, AOGP, and gas to the North in Future 3), cost of power plant demolition, fuel costs, variable generation operating costs, fixed generation operating costs, and purchased power costs. It is important to note that the system costs are not intended to capture all costs but only costs that have an impact on the portfolio on an incremental basis.

8.1.1.1 Capital Costs

Capital costs are key considerations for PREPA in evaluating priorities of new and existing generation options. For the IRP, major capital costs included the following three categories:

- Generation related costs, such as new generation in Palo Seco, Aguirre, or Costa Sur, repowering projects; fuel conversions of the existing units; and demolition costs associated with retired units.
- Fuel infrastructures, such as AOGP in Future 1, 3 and 4, and Gas to North in Future 3.
- Transmission upgrades which include main projects, other projects and support projects. Table 8-1 shows the transmission upgrades capital costs and Volume II provides additional details on these investments.

Capital costs include engineering, procurement and construction as well as financing costs for new generation capital investments and all transmission and distribution capital investments. Capital costs do not include major maintenance costs for generation, which are included explicitly in the IRP in variable operations and maintenance costs. General operations and maintenance costs for transmission are not included as they would not affect the Portfolio selection but are in the order of 2 to 3% of the capital costs.

Table 8-1: Transmission Upgrades Capital Costs

Category	Description	Capital Costs ($2015)
Main Projects	Transmission reinforcement projects (230 kV and 115 kV) required to integrate the new generation portfolios by increasing the transfer capability South to North.	$274 million
Other Projects	Projects and reinforcements required to provide reliability to the system at different voltage levels (transmission, sub-transmission and distribution). These projects are included in the IRP due to the urgent need to reconstruct the system to maintain continuous operation.	$1,662 million
Support Projects	Equipment, tools, facilities improvements necessary to develop the required projects.	$45 million
Total		**$1,981 million**

Source: PREPA, Siemens PTI, Pace Global

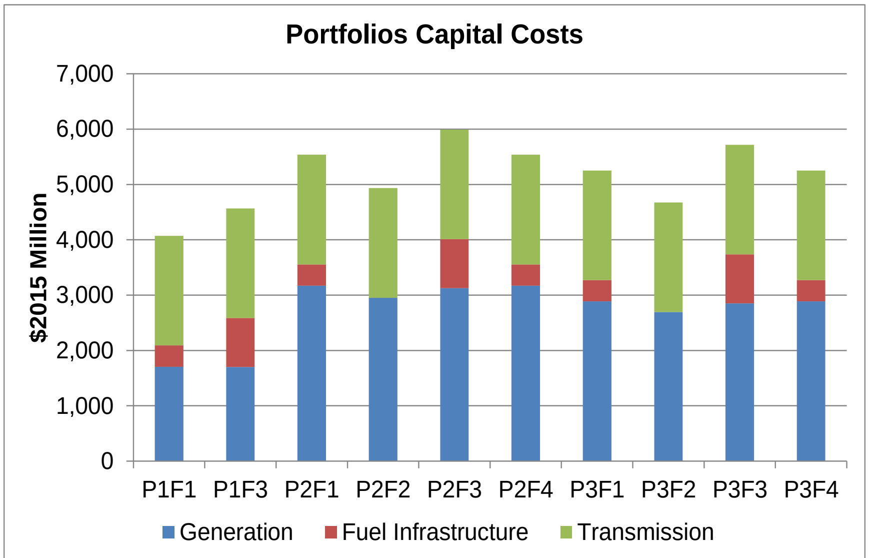
Even though the total transmission capital costs amount to $1,981 million, the capital costs for the main transmission projects which are required to integrate the new generation units are much lower at approximately $274 million. The larger component of the capital costs at the transmission and distribution levels are required to reconstruct and reinforce the system as well as ongoing repair and expansion to serve new customers.

Transmission costs were assumed at the same level across all Futures and Portfolios.

- Transmission costs were the same in Futures 1,3 & 4 given that the generation in the North is minimized and by December 2020 when the Palo Seco Steam Plants (PSSP) and the San Juan Steam Plant (SJSP) are retired (or designated limited use), the only new generation is the new generation at Palo Seco and all the transmission reinforcements are necessary, including the STATCOMs.
- In Future 2, MATS compliance requires the early retirement of the Aguirre 1&2 steam plants and by December 2020 in addition to the new generation at Palo Seco there would be another unit at San Juan (H Class in Portfolio 3). This additional generation would allow postponing some of the transmission reinforcements for this Future. However, as shown in Volume II, Section 5-2, in case that the demand recovers to those levels experienced in 2014, the system would be put at risk if the transmission investment were not made and hence even under this future we are recommending considering these investments.

Overall, the generation and transmission capital costs accounts for over 90 percent of the total capital costs. Portfolio 2 is the most expensive portfolio, primarily because of higher installed new generation capacity. Portfolio 1 is the least expensive portfolio, because the efforts are focused on repowering existing units. Table 8-2 and Table 8-3 present the capital costs of all Portfolios and Futures.

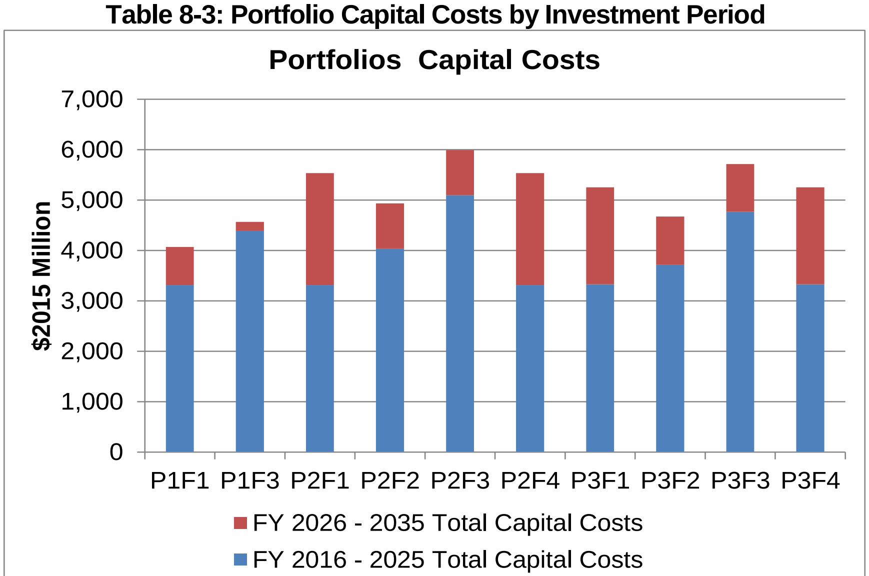
Table 8-2: Portfolios Capital Costs by Category



Capital Costs	Unit	Portfolio 1		Portfolio 2				Portfolio 3			
		P1F1	P1F3	P2F1	P2F2	P2F3	P2F4	P3F1	P3F2	P3F3	P3F4
Generation	*$ million*	1,705	1,700	3,171	2,953	3,125	3,171	2,887	2,693	2,850	2,887
Fuel Infrastructure	*$ million*	385	886	385	0	886	385	385	0	886	385
Transmission	*$ million*	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981
Total	*$ million*	4,071	4,566	5,536	4,933	5,992	5,536	5,252	4,674	5,716	5,252

Source: PREPA, Siemens PTI, Pace Global

Table 8-3: Portfolio Capital Costs by Investment Period



Capital Costs	Unit	Portfolio 1		Portfolio 2				Portfolio 3			
		P1F1	P1F3	P2F1	P2F2	P2F3	P2F4	P3F1	P3F2	P3F3	P3F4
FY 2016 - 2025 Total Capital Costs	*$ million*	3,314	4,387	3,314	4,039	5,097	3,314	3,329	3,715	4,766	3,329
FY 2026 - 2035 Total Capital Costs	*$ million*	757	179	2,223	894	894	2,223	1,923	959	950	1,923
FY 2016 - 2035 Total Capital Costs	*$ million*	4,071	4,566	5,536	4,933	5,992	5,536	5,252	4,674	5,716	5,252

Source: PREPA, Siemens PTI, Pace Global

8.1.1.2 System Costs

The system costs include amortized capital costs (new generation, power plant fuel conversion, transmission upgrades, AOGP, and gas to the North in Future 3), cost of power plant demolition, fuel costs, variable generation operating costs, fixed generation operating costs, purchased power costs from AES and EcoEléctrica, as well as renewable power purchase costs[47]. The present value of the system costs are calculated in real 2015 dollar based on a discount rate of 6.86 percent over the 20-year period.

The cost of capital is assumed at 6.86 percent on a real dollar basis[48]. This is based on discussions with PREPA's financial advisors, who assumed PREPA is able to resolve its current financial issues, and can borrow the capital required to finance cost-effective capacity additions at 9 percent nominal rate. Assuming a long-term inflation rate of 2 percent, we derived a cost of debt of 6.86 percent on a real dollar basis. Given 100 percent debt financing and a non-taxable entity, the Weighted Average Cost of Capital (WACC) is also 6.86 percent.

All scenarios were based on the same discount rate which was selected on the best estimation at the time of the IRP analysis. If the discount rates were higher, which is possible, it would only make the selected Portfolio 3 an even better option than Portfolio 2 as it has the least up front capital of the feasible portfolios. As will be shown later Portfolio 1 while has lower capital, cannot accommodate the required levels of renewable generation.

Amortized capital is calculated based on a 6.86 percent interest rate and an amortization schedule that is consistent with IRS Publication 946 defined class life for different asset classes. For fuel conversion projects capital costs at Aguirre sites and San Juan sites are amortized in five years and 21 years respectively, considering the age of the facilities. For modeling purposes it was assumed that each debt issuance would be repaid according to a mortgage-like schedule (i.e., equal payments in each year), which allows repayment of the debt and provide debt interest payments. Table 8-4 outlines the amortization schedule assumptions of different asset classes.

Table 8-4: Asset Class Amortization Schedule

Asset Class	Class Life (years)
Combined Cycle Plant	28
AOGP Regasification Terminal	22
Existing Unit Fuel Conversion / Switching (Aguirre CC and ST)	5
Existing Unit Fuel Conversion / Switching (San Juan)	21
Transmission Upgrades	30

Source: Pace Global, IRS Publication 946

8.1.2 Environmental and Compliance Metrics

Environmental and compliance metrics focus on system wide emission reduction, CO_2 emissions, MATS compliance status, and RPS and renewable penetration.

[47] Note that the system costs are not intended to capture all costs but only costs that have an impact on the portfolio on an incremental basis.

[48] Equivalent to 9 percent nominal cost of debt as provided by PREPA's financial advisors.

Clean Power Plan thresholds require Puerto Rico to reduce system wide power plant CO_2 emissions to a rate of 1,470 lb/MWh for 2020-2029 period (average) and 1,413 lb/MWh for 2030 and beyond.

On August 3, 2015, EPA finalized standards of performance for new stationary combustion turbines (commenced construction after January 8, 2014) for the control of greenhouse gas (GHG) emissions from electric utility generating units that were constructed with the ability to sell at least 25 MW to a utility distribution system. This subpart applies to combustion turbine units with a design heat input capacity greater than 260 GJ/hr (250 MMBTU/hr) and created standards for three sub-categories of units based on net-electric sales and fuel types used. Oil-fired CT units that do not have natural gas supply (for instance in a Future 2 scenario) are exempt. The finalized GHG standards define CO_2 as the GHG to be regulated with emissions limits specified as those presented in the table below. Since all new applicable NGCC units in this Project will be base load, the 1,000 lb CO_2/MWh standard applies.

Table 8-5: GHG Standards for Affected Combustion Turbines

Affected EGUs	Emission Standard (12-operating-month rolling average basis)
New and reconstructed base load natural-gas fired units [1]	1,000 lb/MWh CO_2
Non-base load natural gas-fired units [1]	120 lb CO_2/MMBtu input [2]
Multi-fuel-fired units [3]	120-160 lb CO_2/MMBtu input [2]

[1] Combust > 90% natural gas on a heat input basis on a 12-operating month rolling average basis
[2] Non-base load units need to meet a clean fuels input-based standard.
[3] Combusts ≤ 90% natural gas on a heat input basis on a 12-operating-month rolling average basis. Units not connected to NG pipeline are exempt.

MATS compliance metrics evaluate the status of existing steam units through fuel switching when gas is available, retirement, limited use designation, when new generations are installed, or extension when neither fuel switching nor retirement is possible.

RPS progress is tracked by the renewable PPOA generation as a percentage of the net sales. This percentage is compared to a reduced RPS goal of 10 percent by 2020, 12 percent by 2025, and 15 percent by 2035. In addition, renewable penetration is tracked by evaluating total renewable generation (both PPOA and DG) as a percent of total customer load (net sales and DG).

8.1.3 Operation Metrics

Renewable energy integration is projected to cause significant operating impacts to PREPA's system. For the IRP, key operation metrics are monitored to assess the reliability, efficiency and stability.

- Curtailment metrics evaluate the portfolio's performance in accommodating renewable generation without excessive curtailment; renewable generation curtailment happens when due to technical requirements of the conventional generating fleet a portion of the renewable generation cannot be accepted in the system and the renewable plant must back down its production although sun irradiation or wind is available[49]. For the IRP, day curtailment during 7AM to midnight is compared across all Portfolios and Futures[50].

[49] Curtailment also can have a financial impact to PREPA as per the existing contractual conditions if energy production capability is available given the meteorological conditions and PREPA cannot take

- Loss of load hours (LOLH) and number of plants that could trigger load shedding are evaluating for all portfolios to assess system reliability and flexibility.
- Reserve margin, calculated as (Resources Available – Peak Load) / Peak Load, is presented for all Portfolio and Future combinations to assess the adequacy of generating capacity to meet the load.
- Number of starts of steam, combined cycle, and GTs are summarized to provide insights into system operation and costs.

8.2 Summary Findings of Portfolio-Futures Combinations

Through extensive evaluation of the three Supply Portfolios under the four Futures, Siemens concluded the following key findings:

- High levels of renewable generation curtailment as the penetration are increased toward the 15 percent level.
- Reduction in the dispatch of the units in the North as more efficient generation is installed in the South for those cases with unavailability of gas in the North and gas is available only at Aguirre and Costa Sur.

Siemens has evaluated all three Supply Portfolios with some sensitivity model runs regarding the technology of the new generation at Palo Seco.

- For Portfolio 1 Future 1, two generation options at Palo Seco including 3 x SCC-800 (P1F1) and 5 x LM6000 (peakers) (P1F1A) are evaluated. The LM6000 generation option at Palo Seco provides insights of relative merits of small CC versus peaker at Palo Seco. In addition, a sensitivity case of P1F1 is run by not repowering Aguirre ST 1 and therefore reducing the generation capacity in the South. This sensitivity case (P1F1RAG) provides insights of potential generation portfolio optimization.
- For Portfolio 2 Future 1, two sensitivity cases are run. The sensitivity case with reciprocating engines (P2F1Re) instead of SCC-800s provides insights of relative merits of small CC versus reciprocating engines at Palo Seco. The 2nd sensitivity case, in which only two (instead of three) new F Class combined cycles are added at the Aguirre site to replace the two steam units, provides insights as to whether reduced new generation capacity improve the overall system performance (P2F1RAG).

Table 8-6 presents the capital and system costs results of all the portfolios.

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it, then it has to be paid at the contractual prices and on an estimate of the energy that could have been produced.

[50] Under some conditions and in particular in the short term, we observed curtailment at night associated with thermal generation and this can be addressed by bringing down some of the units to their emergency "non-regulating" limits. Note however that this cannot be done to mitigate renewable curtailment as thermal generation regulation is a critical element to be able to confront the variability of renewable generation as shown in Volume II.

Table 8-6: PREPA Portfolios System Costs

System Costs	Unit	P1F1	P1F1A	P1F3	P1F1 RAG
Total Present Value of System Costs	*$ million*	27,253	27,279	26,761	27,137
Average Annual System Costs	*$ million*	2,473	2,477	2,418	2,464

System Costs	Unit	P2F1	P2F2	P2F3	P2F4	P2F1Re	P2F1RAG
Total Present Value of System Costs	*$ million*	26,930	30,016	26,871	26,757	26,966	26,928
Average Annual System Costs	*$ million*	2,428	2,767	2,421	2,411	2,431	2,428

System Costs	Unit	P3F1	P3F2	P3F3	P3F4
Total Present Value of System Costs	*$ million*	26,842	29,301	26,660	26,648
Average Annual System Costs	*$ million*	2,415	2,663	2,394	2,397

Source: Siemens PTI, Pace Global

8.2.1 Portfolio 1 Findings

Portfolio 1 involves the least amount of capital costs among the three Portfolios, but incurs the highest system costs due to the less efficient heat rate achieved with repowering. Though all Portfolios exceeded the target curtailment of two percent in certain years, Portfolio 1 has the worst performance in this respect because the limited flexibility added to the system. This added flexibility is not enough to control the curtailment that reaches close to 15 percent towards the end of the period in Future 3. As shown in Appendix B, several existing PREPA units have high minimum stable loading values. However, we understand from PREPA[51] that the units have undergone modifications and the current values are the best that can be achieved and still maintain the regulating capability of these units.

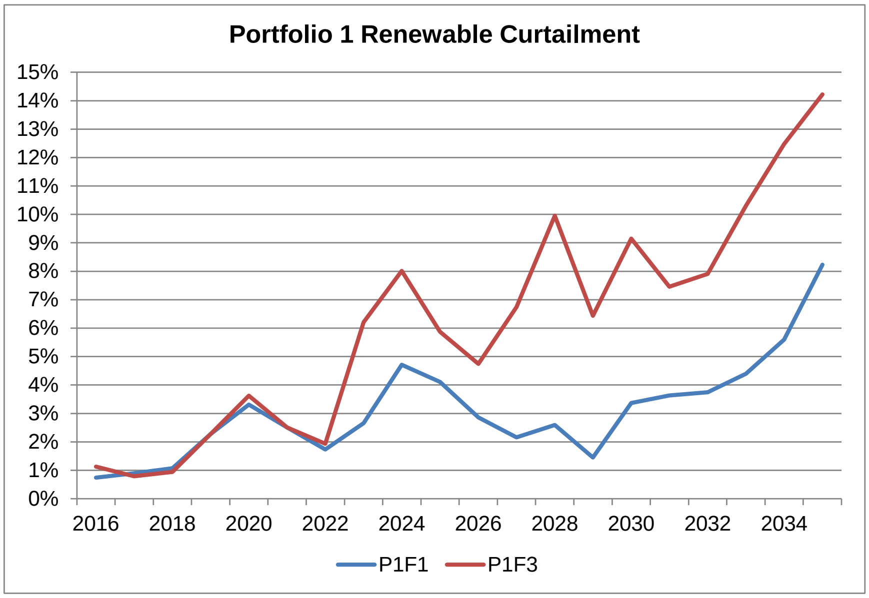
It is important to note that the reduction in curtailment from 2026 to 2029, comes at the expense of higher risk and operating costs to the system as for each of the four years one of the Aguirre 1&2 or Costa Sur 5&6 units was out of service for the repowering and this reduced generation also translated in reduced curtailment. As a test, we ran sensitivity (P1F1RAG), where we did not repower one of the Aguirre units but instead retired it after the units at Costa Sur 5&6 were repowered. This case resulted in reduced curtailment but it was still above the accepted threshold of 2 percent, and it has greater risk of supply interruptions.

Figure 8-1 present the model run results regarding curtailment for Portfolio 1. We note that the higher curtailment associated with Future 3 is possibly related to the optimization done by PROMOD. In Future 3, all new combined cycle plants have gas (both in the North and South) and the optimal solution, derived by PROMOD, results in much less cycling of these units and hence reduced ability to accommodate renewable generation. As an example, the new Palo Seco combined cycle that run with diesel in Future 1 is turned on and off almost every day, but cycles much less in Future 3, with an average of 80 cycles per year.

Based on the above we can conclude that Portfolio 1 is unable to handle more than approximately 10 percent RPS level without excessive costs. Note that instead of running Portfolio 1 under Future 4, which doubles the amount of distributed generation and would only further exacerbate the curtailment, we elected to run the scenario with one Aguirre unit less (P1F1RAG).

[51] Based on discussions with PREPA. The Siemens team has not been provided any report or material supporting the claim.

Figure 8-1: Portfolio 1 Curtailment



Source: Siemens PTI, Pace Global

The net demand (gross demand less renewable generation) is declining over the period under analysis and this result in declining capacity factors for the generation in general. However the generation in the North in Future 1 is fired with diesel and results in much lower capacity factors as compared with the generation in the South that is fired with less expensive natural gas at Costa Sur and Aguirre after July 1, 2017. This situation becomes more pronounced after the Aguirre and Costa Sur units are repowered, adding an additional 180 MW in the South. To address the situation above, we investigated the option of installing peaking units (5 x LM6000) with a total capacity of 238 MW. The LM6000 units have lower capital costs but higher heat rate relative to the SCC-800 combined cycle.

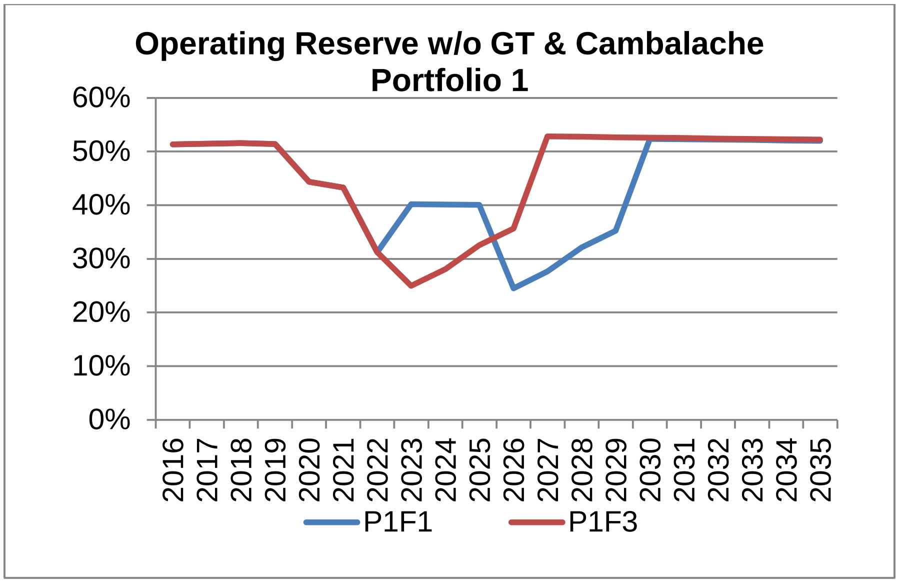
The LM6000 option resulted in higher present value of the total system costs than the SCC-800 combined cycle over the study period (P1F1A in Table 8-6). In conclusion, we recommend discarding the LM6000 as an option going forward for the following reasons:

- There would have to be extremely low capacity factors throughout the period of analysis for the LM6000 option to be advantageous. A capacity factor of 5 percent would make the two options the same.
- The LM6000 would be a much worse option if natural gas became available in the North because of its lower efficiency relative to the SCC-800 combined cycle. It would be possible to convert the simple cycle units to combined cycle but the economics favor building the combined cycle initially.

Portfolio 1, once fully implemented has an operational reserve level of 52 percent considering only the base generating units in the system and the relatively new units of Mayagüez; that is not considering the capacity in the old 18x21 MW gas turbines or the Cambalache units.

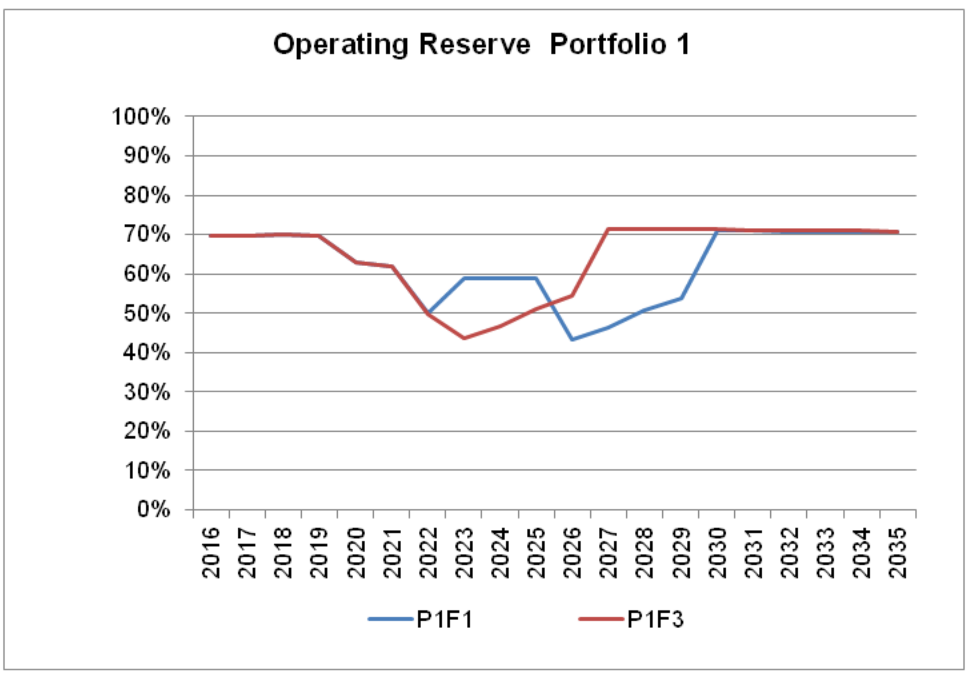
As can be observed in the figure below the operational reserve is expected to drop to close to 25 percent in transition years when the units at Aguirre 1&2 are expected to go out of service for repowering. These low reserve years however did not result in LOLH.

Figure 8-2: Portfolio 1 Operating Reserve without GTs or Cambalache



Considering the 18x21 MW GTs and Cambalache, the final reserve is high at 71 percent indicating the possibility of retiring some of these units once the transmission system is reinforced. Figure 8-3 shows the evolution of this reserve for both Future 1 and 3.

Figure 8-3: Portfolio 1 Operating Reserve with GTs and Cambalache

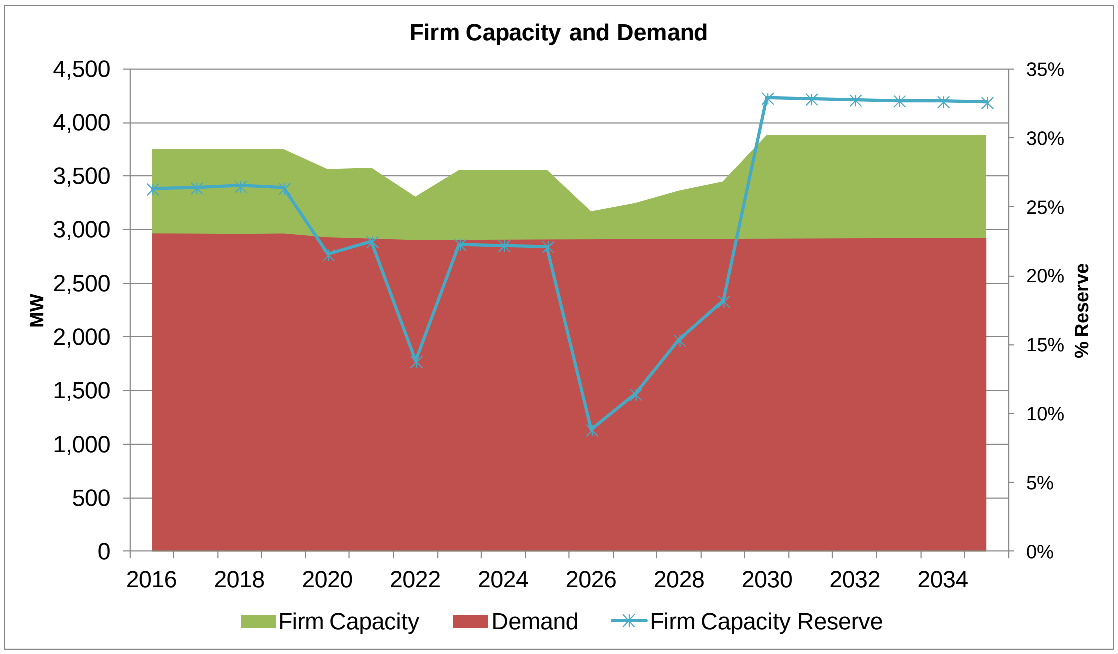


Another way to consider the adequacy of the generation to supply the load is a modified version of the reserve calculation above using the concept of "Firm Capacity"; this is the actual contribution to supply the load of a generation resource adjusted by its availability.

There are various methods with increasing level of accuracy to determine this value, but this can be approximated by multiplying the units nominal capacity times its availability.

This calculation was done for Portfolio 1 and the results are shown in the figure below where we observe that the Firm Capacity (not including the 18x21 MW GTs or the Cambalache units) increases from 3,750 MW to 3,881 MW and towards the end of the period, the margin of the Firm Capacity over the Future 1 demand is about 33 percent, which is still on the high side but in line with our expectations for an isolated power system like Puerto Rico. Future 1, 2 and 3 have the same demand forecast, while Future 4 has slightly lower demand and its analysis would show only timing differences on the reserve but the end value would be the same. Detailed demand forecast is outlined in Volume III of the IRP report.

Figure 8-4: P1F1 Firm Capacity and Demand Comparison



In summary, Portfolio 1 has the lowest capital costs but this comes at the expense of not being able to incorporate the required levels of renewable generation and it has the highest level of present value of system costs when compared with other portfolios under Future 1. In Future 3, Portfolio 1 has slightly lower costs than Portfolio 2, but still higher than Portfolio 3. The sensitivities evaluated for this Portfolio changing key inputs did not result in an improvement in performance. We present additional details on the performance of this portfolio in Sections 8.3 to 8.5 below.

8.2.2 Portfolio 2 Findings

The most important finding of Portfolio 2 is that the replacement of Aguirre ST 1&2 and Costa Sur ST 5&6 by modern F Class combined cycle is enough to reduce the curtailment to negligible values up to the tested RPS level of 15 percent and beyond as shown in Section 9.1 of this report. However, before these investments are made, there are high curtailments in the system.

In all four Futures, we observe that before the new CCs at Aguirre and Costa Sur come online the curtailment reaches 5 to 11 percent. Future 2 has the lowest curtailment due to the acceleration of the retirement of the Aguirre steam units. The highest curtailment occur in Future 3 where after gas is available in the North the units there are run at higher levels and the optimal strategy have them turn off less often resulting in a slightly higher curtailment (this was also observed for Portfolio 1).

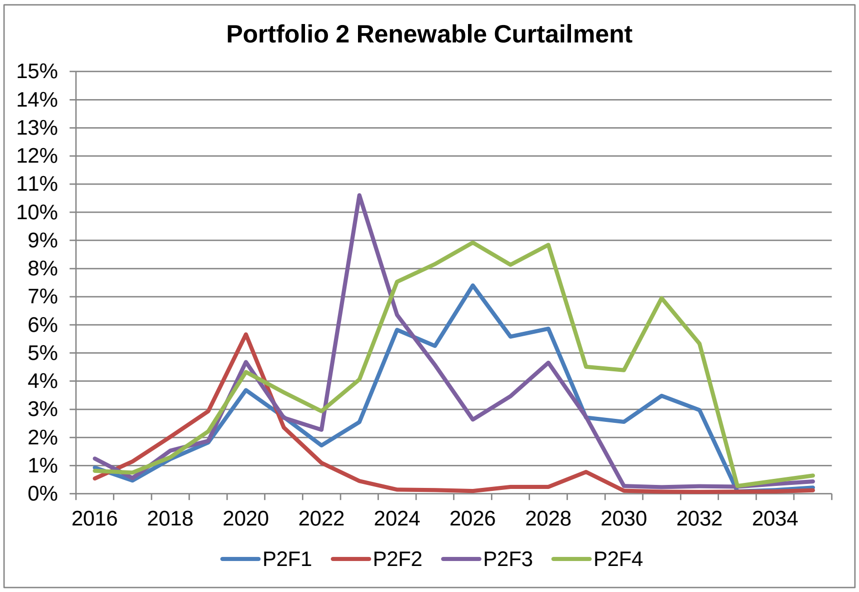
The drop in the dispatch of the new units in the North for Portfolio 2 is more pronounced than for Portfolio 1 for those cases where the gas is available only in the South. Given that the LM6000 was not a good option, we investigated the use of reciprocating engines (RE) consisting of 12 Wärtsila units, each one of which is 17.2 MW. These units have relatively low capital costs and acceptable efficiency, thus for low capacity factors we expected them to provide better results than the SCC-800. We found that for Future 1, P2F1 with the SCC-800 has slightly lower production costs than P2F1 with reciprocating engines (P2F1Re). The key observation in the relative economics of SCC-800 vs. reciprocating engines is that even though the SCC-800 has higher capital costs, the higher efficiency results in fuel savings, higher dispatch and overall lower system costs. As a test, we ran sensitivity (P2F1RAG), in which only two (instead of three) new F Class combined cycles are added at the Aguirre site to replace the two steam units. This case resulted in slightly lower net present value of system costs.

Given that for Future 1, the results with the SCC-800 and the Wärtsila reciprocating engines are very similar, it is recommended that the reciprocating engines be discarded as an option for the IRP purposes and the analysis focus on the SCC-800 for Portfolio 1 and 2. When actual generation expansion projects are planned, these technology options can be explored in greater detail, based on the then current outlook for fuels and demand.

Portfolio 2 has highest capital costs but when it is fully deployed (Aguirre Steam and Cost Sur Steam are replaced), it is able to incorporate the required levels of renewable generation. Portfolio 2 however has higher present value of system costs than Portfolio 3 under all Futures. We evaluated a sensitivity case where the third F Class combined cycle at Aguirre was not installed under P2F1, but this did not significantly improve the present value of system costs; the increase in operating costs negated the gains in reduced capital.

We present additional details on the performance of Portfolio 2 in Sections 8.6 to 8.9 below.

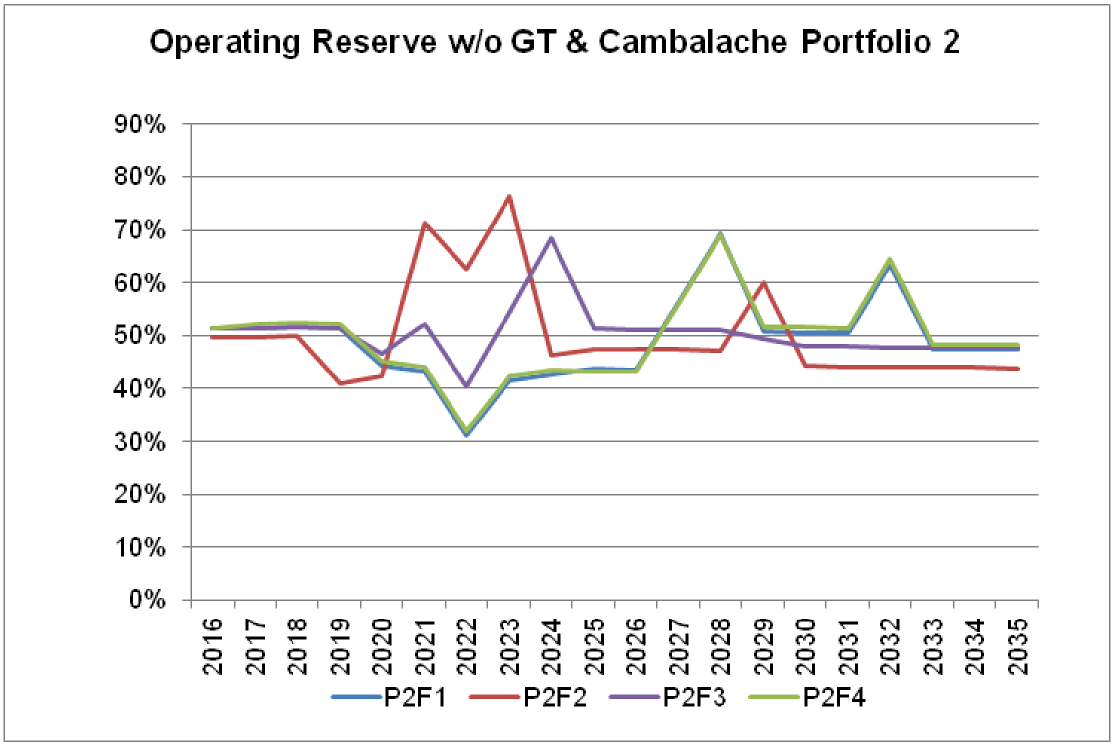
Figure 8-5: Portfolio 2 Curtailment



Source: Siemens PTI, Pace Global

The operational reserve for this Portfolio 2 not considering the Cambalache units or the 18x21 MW GT units ends being 48 percent once all the changes associated with it are implemented as shown in the figure below. Note that under Future 2 that does not have the AOGP the reserve is lower (44 percent) as the new combined cycle on LFO has lower capacity.

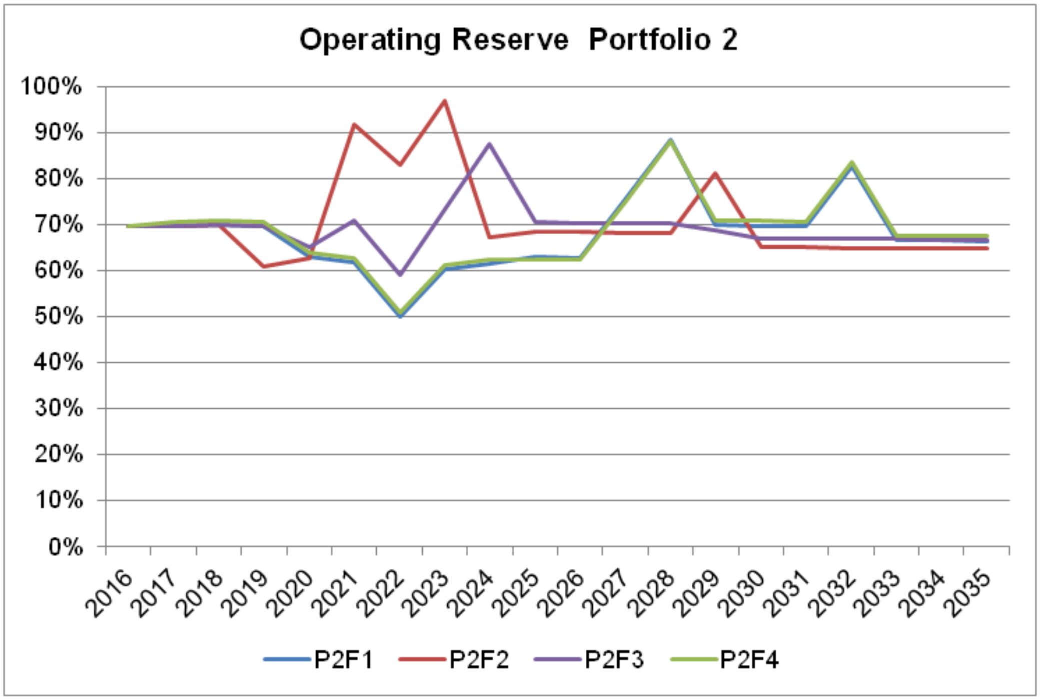
Figure 8-6: Portfolio 2 Operating Reserve without GTs or Cambalache



Source: Siemens PTI, Pace Global

Considering the 18x21 MW GTs and Cambalache the final reserve is high at 68 percent indicating the possibility of retiring some of these units once the transmission system is reinforced. Figure 8-7 shows the evolution of this reserve for all Futures.

Figure 8-7: Portfolio 2 Operating Reserve with GTs and Cambalache

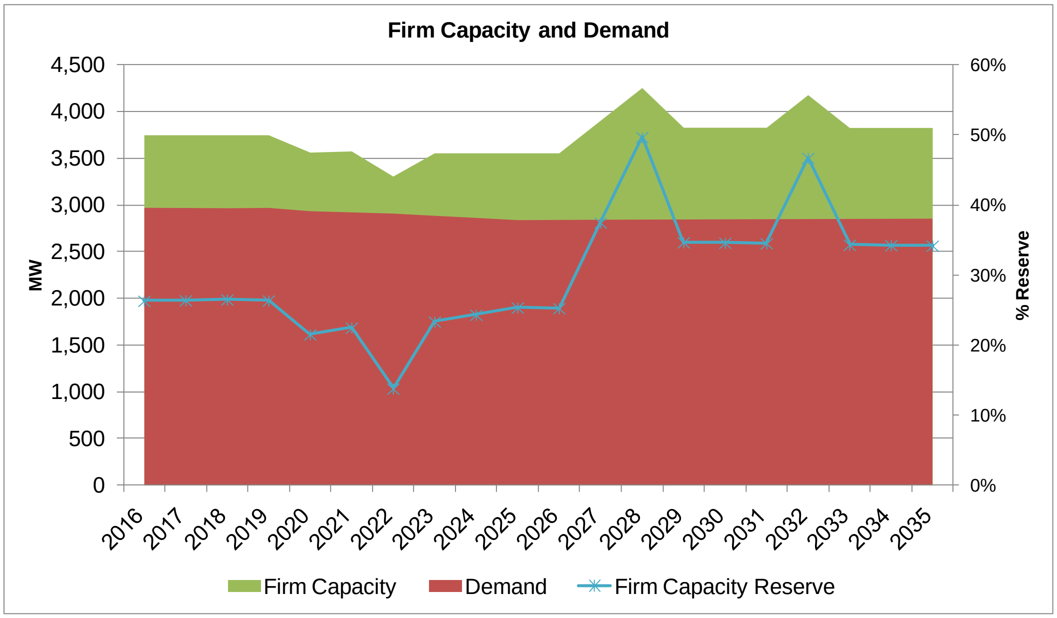


Source: Siemens PTI, Pace Global

It should be indicated that the jumps observed in the reserve margin above correspond to the transition years where for example one of the new Aguirre CC is online but the other is under construction and both Aguirre 1&2 are available.

Using the concept of Firm Capacity, we observe that with this portfolio the firm capacity increase slightly from 3,750 MW to 3,829 MW and the reserve over the Future 1 demand has a final value of 34 percent, which is in the order of what we would expect for an isolated system like Puerto Rico. The value above corresponds to the futures with the AOGP. Future 1, 2 and 3 have the same demand forecast, while Future 4 has slightly lower demand and its analysis would show only timing differences on the reserve but the end value would be the same. Detailed demand forecast is outlined in Volume III of the IRP report.

Figure 8-8: Portfolio 2 Firm Capacity and Demand Comparison



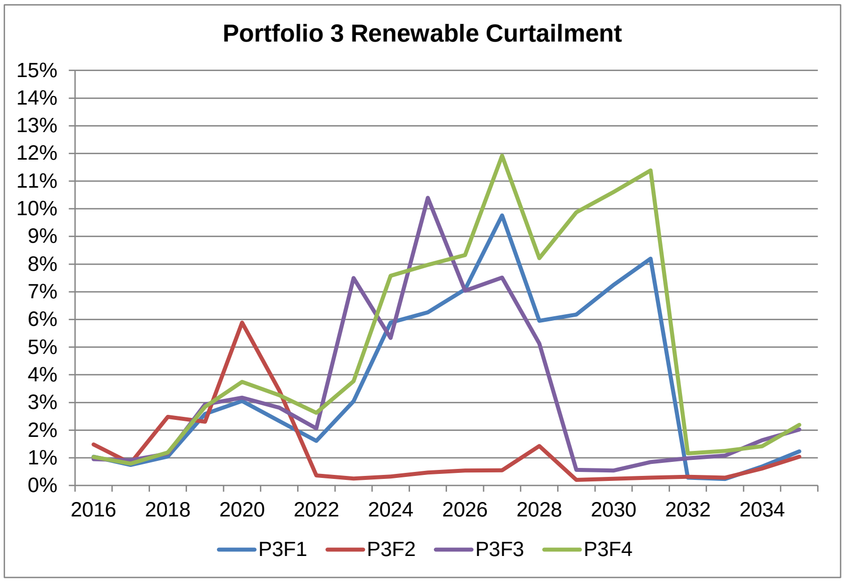
Source: Siemens PTI, Pace Global

We present additional details on the performance of this portfolio in Sections 8.6 to 8.9 below.

8.2.3 Portfolio 3 Findings

In Portfolio 3, the replacement of Aguirre ST 1&2 and Costa Sur 5&6 by modern H Class combined cycle reduces the curtailment to below the two percent limit once all new generation units come on line. However, before this investment is made, there are significant curtailments. This is shown in Figure 8-9, where we observe that before the new CCs at Aguirre and Costa Sur come online the curtailment reaches 5 to 10 percent.

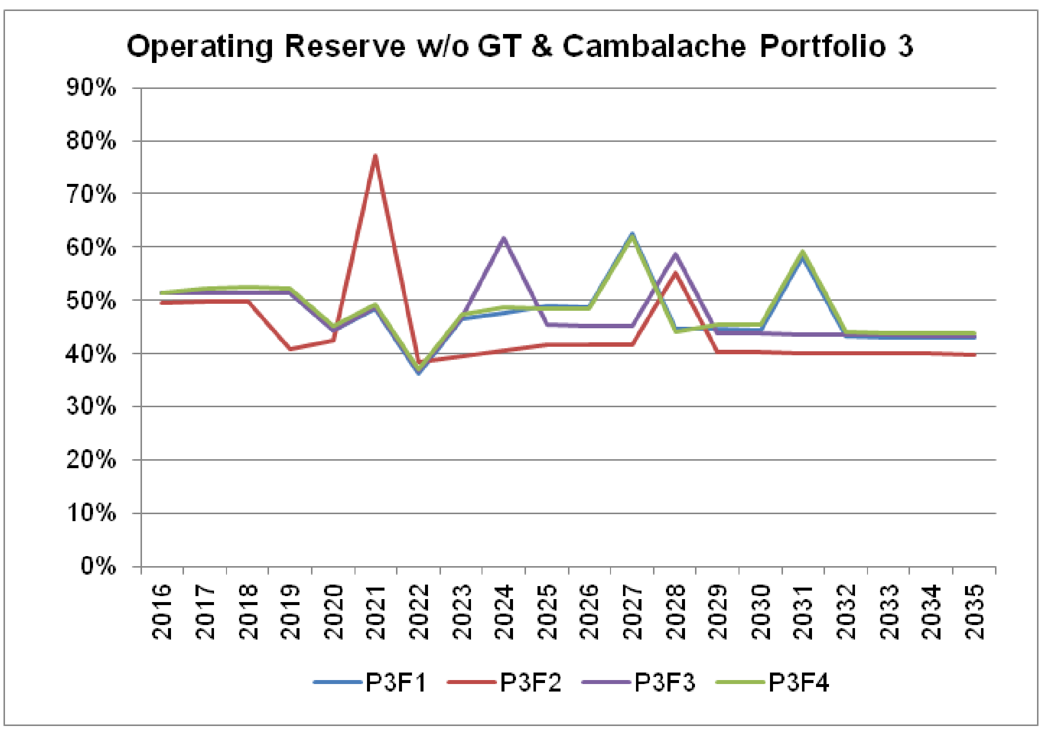
Figure 8-9: Portfolio 3 Curtailment



Source: Siemens PTI, Pace Global

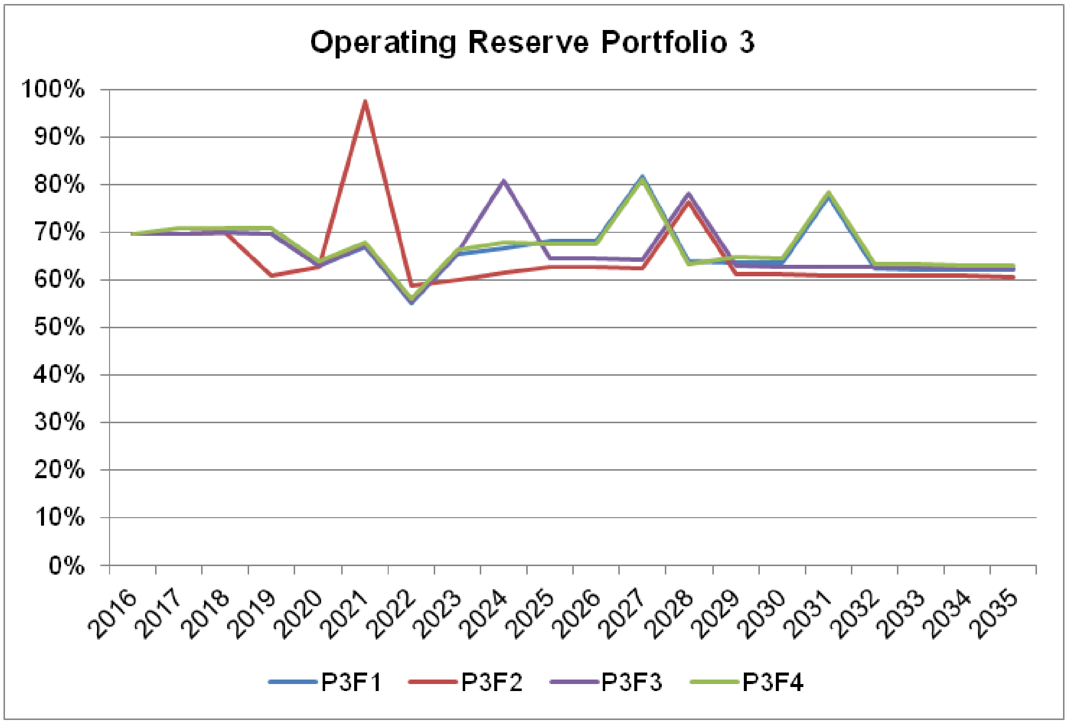
The operational reserve for this Portfolio 3 not considering the Cambalache units or the 18x21 MW GT units ends being 44 percent once all the changes associated with it are implemented as shown in the figure below. Note that under Future 2 that does not have the AOGP the reserve is lower (40 percent) as the new combined cycle on LFO has lower capacity.

Figure 8-10: Portfolio 3 Operating Reserve without GTs or Cambalache



Considering the 18x21 MW GTs and Cambalache the final reserve is high at 63 percent indicating the possibility of retiring some of these units once the transmission system is reinforced. Figure 8-11 shows the evolution of this reserve for all scenarios.

Figure 8-11: Portfolio 3 Operating Reserve with GTs and Cambalache

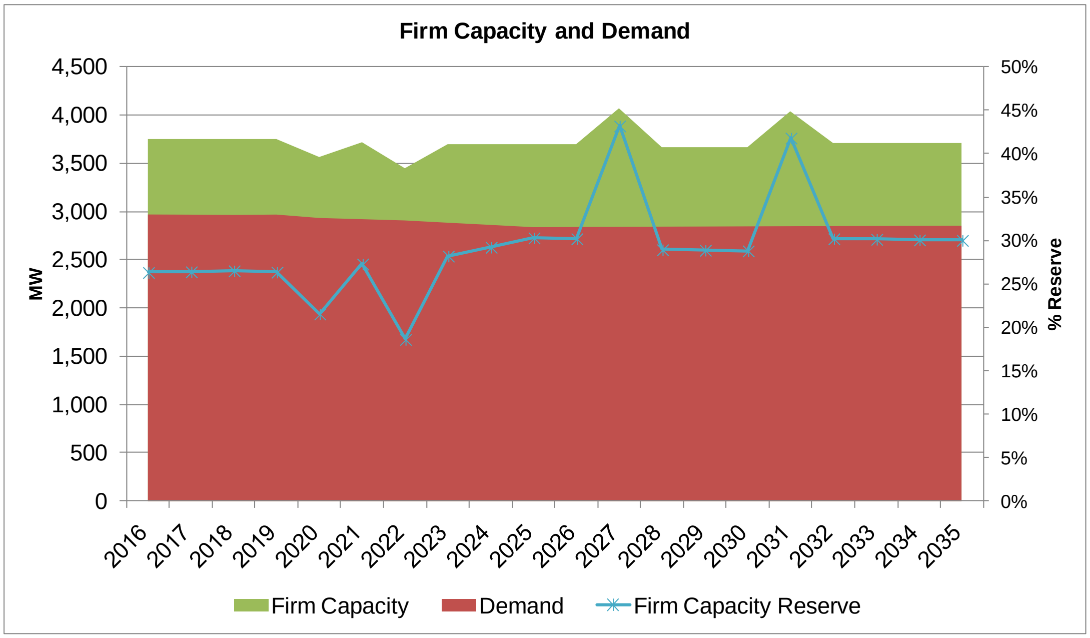


Source: Siemens PTI, Pace Global

As in Portfolio 2, it should be indicated that the jumps observed in the reserve above correspond to the transition years where for example one of the new Aguirre CC is online but the other is under construction and both Aguirre 1&2 are available.

Using the concept of Firm Capacity, we observe that with this portfolio the firm capacity decreases slightly from 3,750 MW to 3,709 MW and the reserve over the Future 1 demand has a final value of 30 percent, which is in the order of what we would expect for an isolated system like Puerto Rico. The value above corresponds to the futures with the AOGP. Future 1, 2 and 3 have the same demand forecast, while Future 4 has slightly lower demand and its analysis would show only timing differences on the reserve but the end value would be the same. Detailed demand forecast is outlined in Volume III of the IRP report.

Figure 8-12: Portfolio 3 Firm Capacity and Demand Comparison



Source: Siemens PTI, Pace Global

This portfolio has the minimum value of the system cost and has lower capital requirements than Portfolio 2. Sections 8.10 to 8.13 provide further details on the performance of this portfolio and it can be observed that it complies with all required criteria. Portfolio 3 is the recommended portfolio.

8.3 Portfolio 1 Future 1 (P1F1)

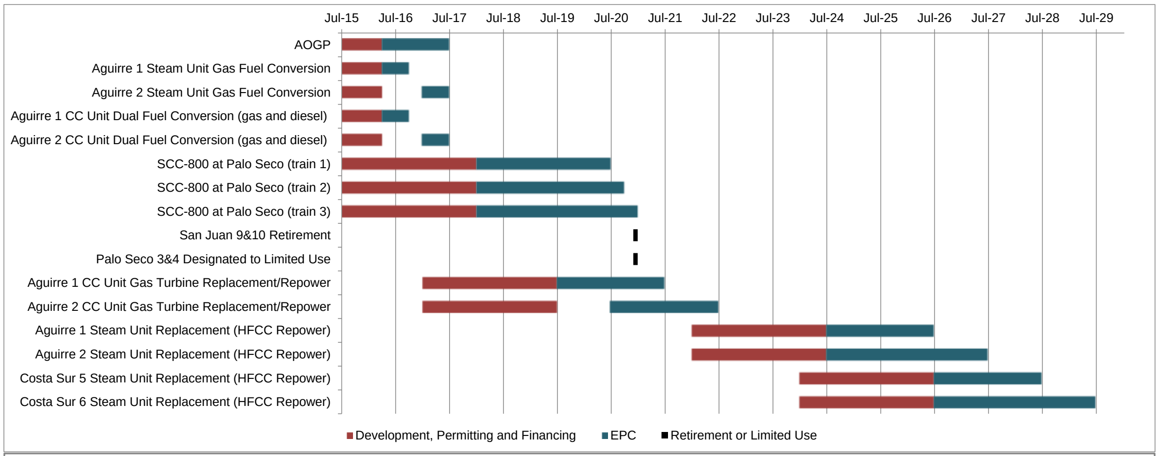
P1F1 key decisions include:

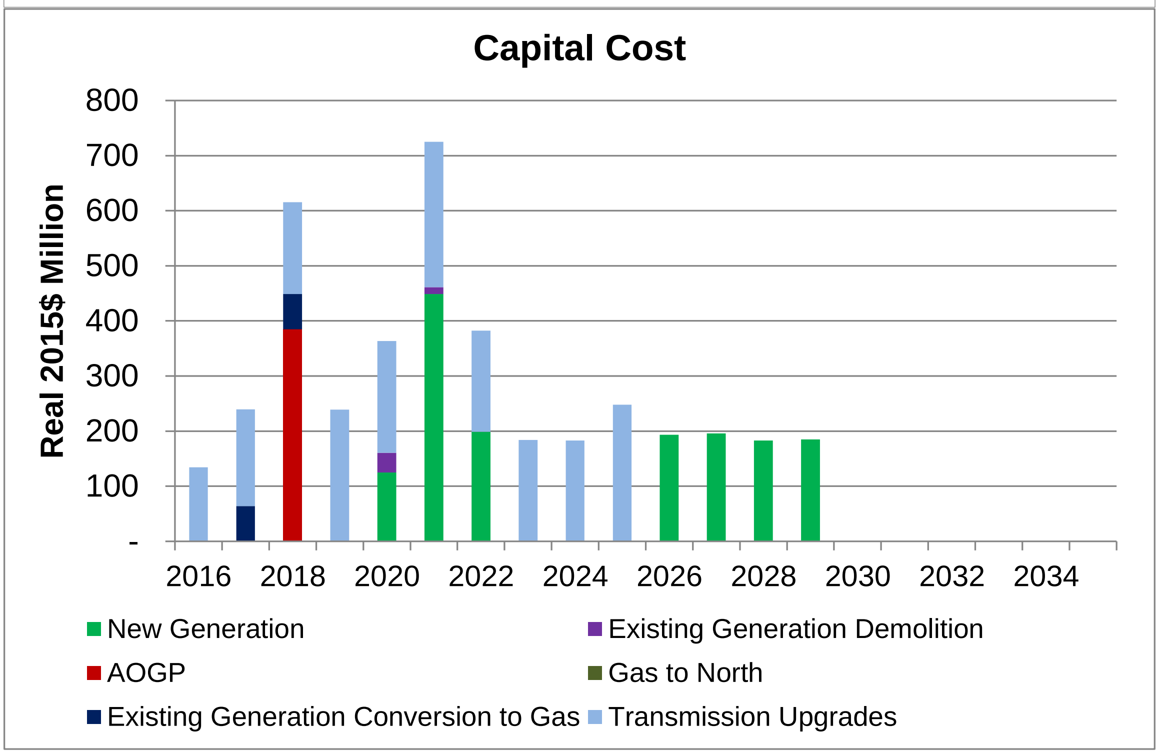
1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017.
2. New generation with diesel as primary fuel will be installed at Palo Seco site by December 31, 2020.
3. Aguirre CC 1&2 repower by the end of 2021 and 2022 with natural gas as primary fuel.
4. Aguirre ST 1&2 HFCC repower by the end of 2026 and 2027 with natural gas as primary fuel.

5. Costa Sur 5&6 HFCC repower by the end of 2028 and 2029 with natural gas as primary fuel.
6. San Juan 9&10 will retire and Palo Seco 3&4 will be designated to limited use by December 31, 2020.

P1F1 timeline and capital costs are presented in Figure 8-13, indicating key portfolio retirement, fuel switching, and new build schedules. P1F1 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-14. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

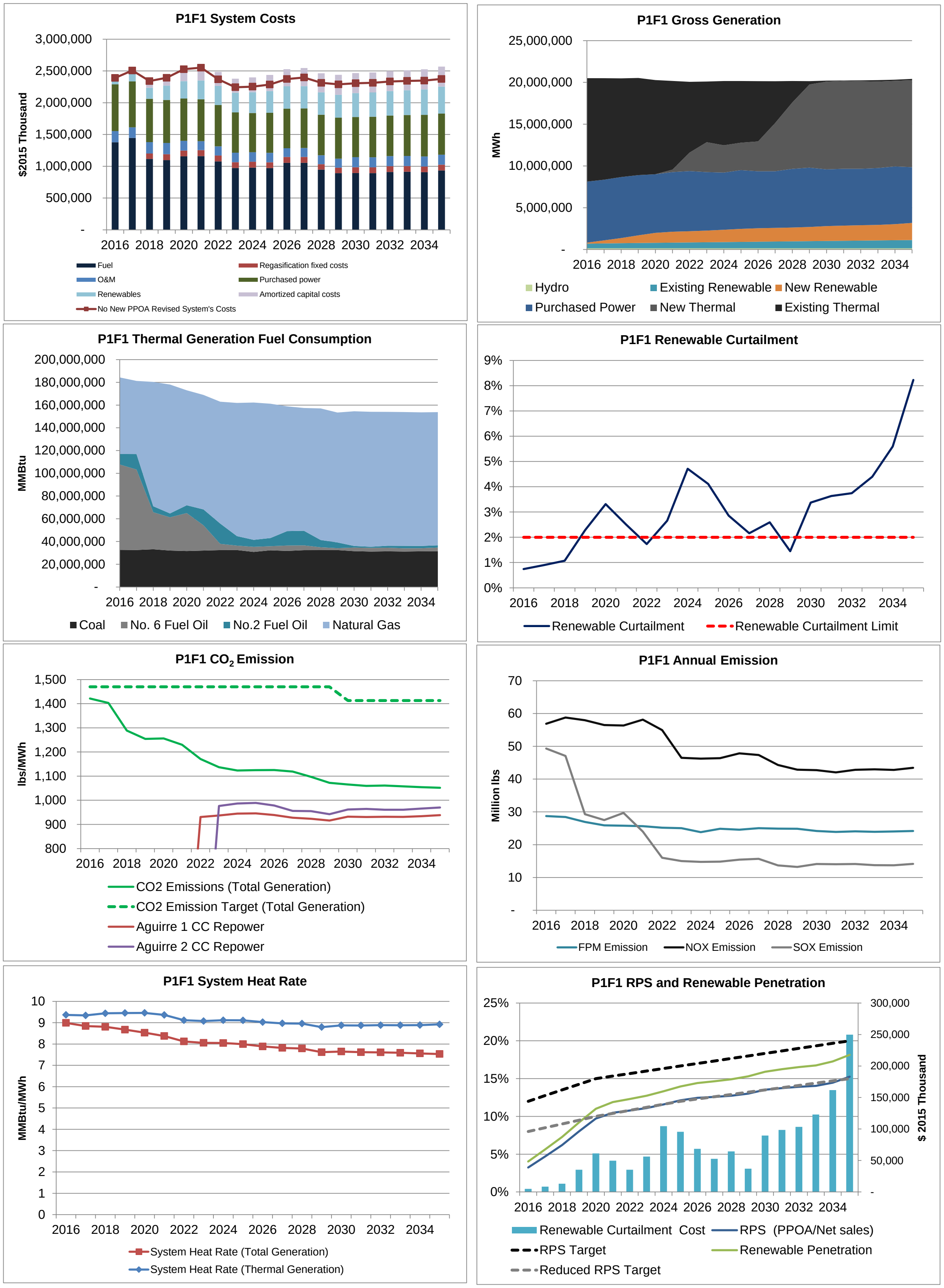
Figure 8-13: P1F1 Schedules and Capital Costs





Source: Siemens PTI, Pace Global

Figure 8-14: P1F1 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.3.1 Cost Summary

The portfolio capital cost requirements are close to $4.07 billion during 2016-2035, with $3.31 billion during 2016-2025 and $0.76 billion during 2026-2035. System costs average $2.47 billion per year over the forecast period. The present value of system costs aggregates to $27.25 billion over the 2016-2035 forecast period. The annual system costs increase over the study period by 0.38 percent per year on a real basis as the fuel cost savings are not enough to offset the renewable power purchase costs and amortized capital costs associated with the repowering, new generation and transmission builds. However, the annual fuel costs decrease by 2.03 percent per year over the study period. The reduction in fuel costs is primarily driven by the increased share of natural gas consumption, and system thermal generation heat rate improvement from 9,367 Btu/kWh in 2016 to 8,922 Btu/kWh in 2035.

The portfolio results show a significant decline in oil consumption and generation from oil fired resources. The oil fired generation is replaced with natural gas fired generation and renewable generation over time. The biggest change in natural gas fired generation occurs in 2017 when AOGP comes online and Aguirre steam and combined cycle units undergo fuel conversion and start to burn natural gas. However, natural gas consumption decreases over time due to greater renewable penetration.

Purchased power costs from AES and EcoEléctrica thermal plants are relatively constant over the forecast horizon as these units are base-loaded units with the lowest production costs and new unit additions and system improvements do not materially alter the dispatch profile of these facilities.

8.3.2 Environmental Compliance Summary

The portfolio results indicate compliance with the proposed Clean Power Plan requirements and the greenhouse gas (GHG) New Source Standard. This later fact was verified at the unit level CO_2 emission rates as shown in Figure 8-14.

The emission rate declines over time as the portfolio mix changes from oil fired generation capacity to new, more efficient natural gas fired generation capacity and greater renewable capacity. Total CO_2 emission rates are expected to decline by 26 percent from 1,421 lb/MWh in 2016 to 1,052 lb/MWh in 2035. In our opinion the GHG New Source Standard only apply to this Portfolio and Future for the Aguirre Repower CC 1&2 as the new combined cycle units at Palo Seco and operate with light distillate.

The repowering of Aguirre and Costa Sur should not qualify as a new source because the increase in capacity is marginal and the units are largely steam electric. The HFCC conversion might be considered a modification to an existing source under section III.A.3, Sources Not Subject to This Rulemaking, of the proposed rules issued January 8, 2014. In this case, the CO_2 limit would not apply. In the alternative, the new Gas Turbine itself could be permitted as a combined cycle unit, taking credit for the generation from the existing Steam Turbine Generator attributable to the GT exhaust heat injected into the boiler, based on the proportionate amount of steam generated from GT exhaust vs. boiler fuel. This approach likely would allow the new GT to meet the CO_2 standard.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 18.14 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources and additional generic projects were added.

8.3.3 Operational Performance Summary

In the near term, day-time renewable curtailments are within the two percent threshold. However, in the mid- to long-term, the curtailments exceed the threshold as both utility scale and distributed solar penetration increases. This suggests that the portfolio does not have sufficient operational flexibility to accommodate renewable energy. This is expected as this portfolio has a significant repowering component and has higher minimum turndowns relative to other portfolios and longer must run time.

The portfolio performs well in terms of reliability with zero loss of load hours in most years except 2021 and 2022 (when the Aguirre CC are being repowered) in the short term and 2026 and 2027 in the longer term. Of these years only FY 2022 exceed significantly the target of 4 hours (with 9 hours reported) and it was investigated further. It was found that during these hours there were multiple units out of service[52] . Even though the event leading to this target violation was extreme we assessed what would be the impact if four of the existing units at the Aguirre CC 1&2 that is repowered[53] (4x50 MW) and the Cambalache unit 1 (83 MW) that was assumed unavailable, were maintained in service. In this case, we found that with this additional 283 MW there would be only 3 hours on the entire period when there would not be enough online generation to supply the load.

In summary we conclude that the operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

8.4 Portfolio 1 Future 3 (P1F3)

P1F3 key decisions include:

1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017.
2. New generation will be installed at Palo Seco by December 31, 2020. The new generation will burn diesel initially and switch to natural gas when gas to the North is available by July 1, 2022.
3. Aguirre CC 1&2 repower by the end of 2021 and 2022 with natural gas as primary fuel.
4. Aguirre ST 1&2 HFCC repower by the end of 2023 and 2024 with natural gas as primary fuel.
5. Costa Sur 5&6 HFCC repower by the end of 2025 and 2026 with natural gas as primary fuel.

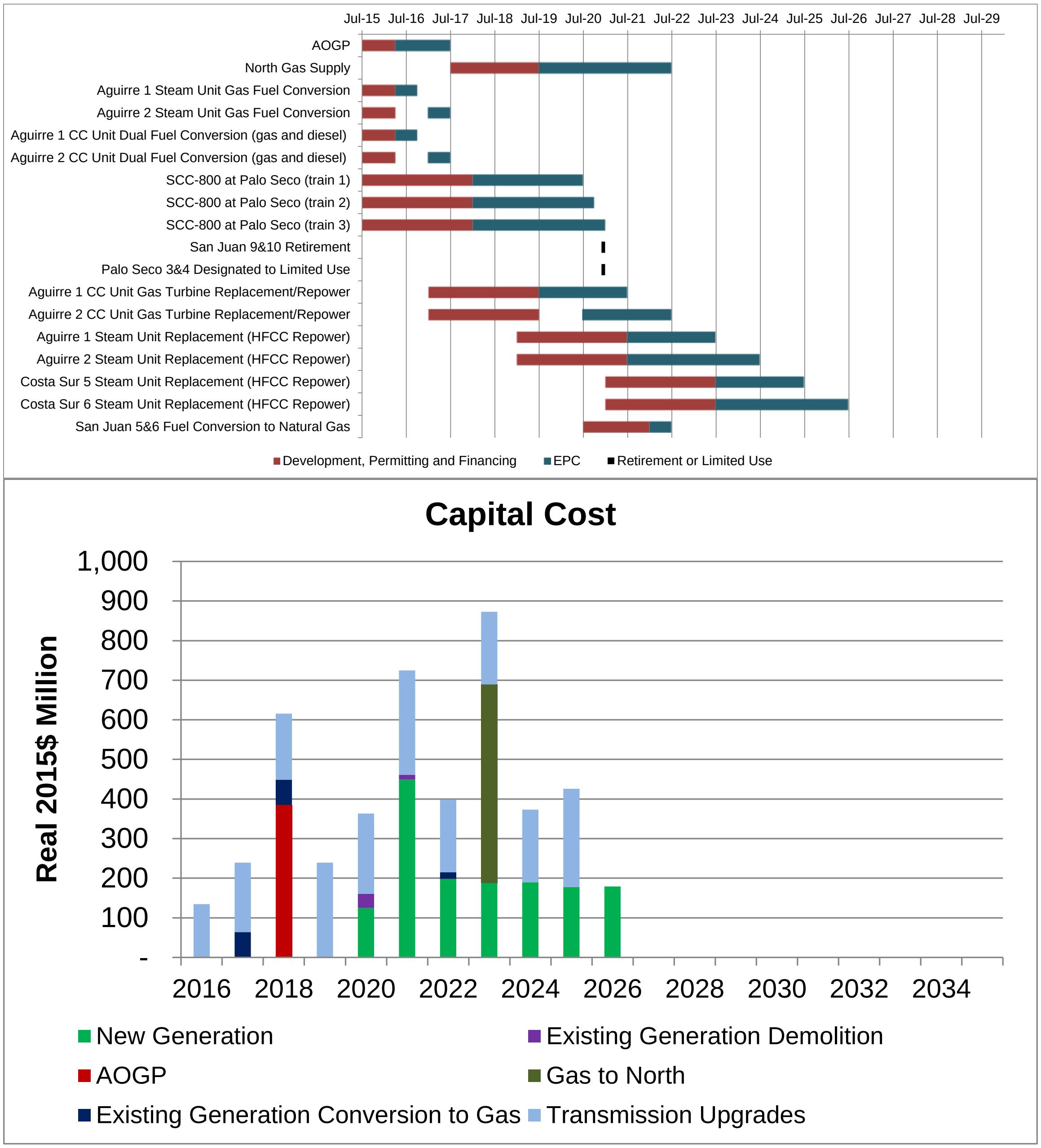
[52] Two events: a) 7/30/2021 with one AES unit, Aguirre ST 1&2 out, Costa Sur 5&6 and one Aguirre CC out of service, and b) 8/12/2021 with one AES unit, Aguirre ST 1, San Juan CC 1 out and Costa Sur 5&6 out of service.

[53] For repowering 4x50 MW GTs will need to be repositioned while the other 4 can stay in place. The generator step up transformer will need to be upgraded however.

6. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

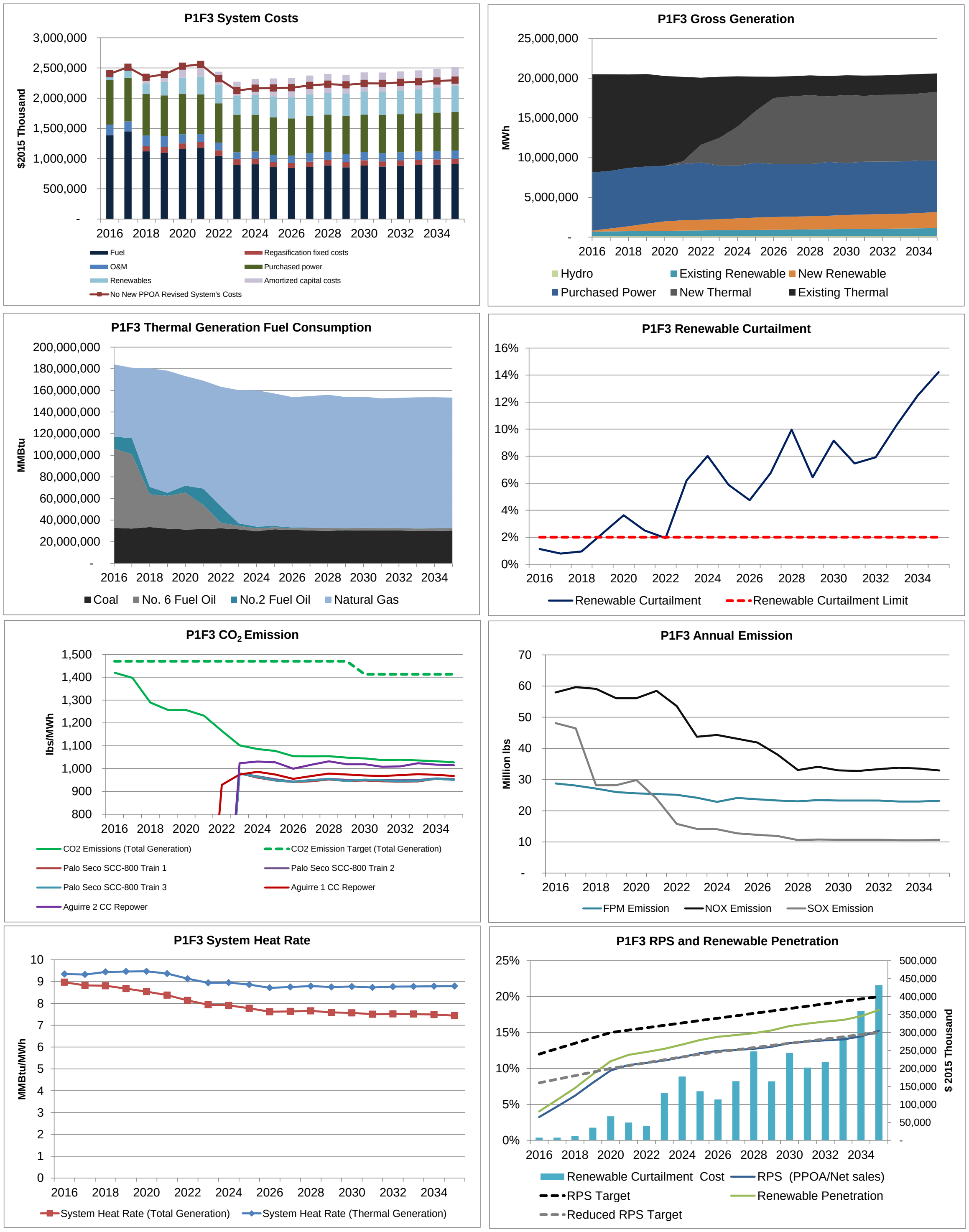
P1F3 timeline and capital costs are presented in Figure 8-15 indicating key portfolio retirement, fuel switching, and new build schedules. P1F3 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-16. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

Figure 8-15: P1F3 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

Figure 8-16: P1F3 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.4.1 Cost Summary

The portfolio capital cost requirements are close to $4.57 billion during 2016-2035, with $4.39 billion during 2016-2025 and $0.18 billion during 2026-2035. System costs average $2.42 billion per year over the forecast period. The present value of system costs aggregates to $26.76 billion over the 2016-2035 forecast period. The annual portfolio or system costs increase over the forecast horizon by 0.24 percent per year on a real basis as the fuel cost savings are not enough to offset the renewable power purchase costs and amortized capital costs associated with the repowering, new generation and transmission builds. The annual fuel costs decrease by 2.19 percent per year over the study period. The reduction in fuel costs is primarily driven by the increased share of natural gas consumption, and system thermal generation heat rate improvement from 9,345 Btu/kWh in 2016 to 8,795 Btu/kWh in 2035.

The portfolio results show a significant decline in oil consumption and generation from oil fired resources. The oil fired generation is replaced with natural gas fired generation and renewable generation over time. The biggest change in natural gas fired generation occurs in 2017 when AOGP comes online and Aguirre steam and combined cycle units undergo fuel conversion and start to burn natural gas. When gas to the North becomes available in 2023, the system gas consumption goes through another increase.

Purchased power costs from AES and EcoEléctrica thermal plants are relatively constant over the forecast horizon as these units are base-loaded units with the lowest production costs and new unit additions and system improvements do not materially alter the dispatch profile of these facilities.

8.4.2 Environmental Compliance Summary

The portfolio results indicate compliance with the proposed Clean Power Plan requirements, but it is marginal with respect of the GHG New Source Standard. The CC at Palo Seco are below the 1,000 lb CO_2/MWh limit and are in compliance and the Aguirre Repower when considered in aggregate are slightly below the limit for large sources (1,000 lb CO_2/MWh) but one of them (Aguirre CC 2) is slightly above the limit and the other slightly below (see Figure 8-16). This incompliance can be addressed by adjusting the dispatch of the units by considering the restriction on emissions so that both Aguirre CC 1 and Aguirre CC 2 are above the minimum dispatch levels below which there are compliance issues (See Volume IV for further details on Compliance Startegy).

As shown in Figure 8-16, the portfolio meets the target emission rate in 2017 once AOGP becomes operational. The emission rate declines over time as the portfolio mix changes from oil fired generation capacity to new, more efficient natural gas fired generation capacity and greater renewable capacity. Total CO_2 emission rates are expected to decline by 28 percent from 1,420 lb/MWh in 2016 to 1,028 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 18.14 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.4.3 Operational Performance Summary

In the near and medium term, day-time renewable curtailments are within the two percent threshold. However, in the out years, the curtailments exceed the threshold as both utility scale and distributed solar penetration increases. This suggests that the portfolio may not have sufficient operational flexibility to accommodate renewable energy. This is expected as this portfolio has a significant repowering component and may have higher minimum turndowns relative to other portfolios.

The portfolio performs well in terms of reliability with zero loss of load hours in most years except in 2021 and 2022. As before only in 2022 the threshold of 4 hours was exceeded and further investigation indicated that it was due to multiple unit outages. If the Cambalache unit 1 is brought back in service and four surplus units of the Aguirre CC repower are available, we estimate that there would be zero LOLH. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

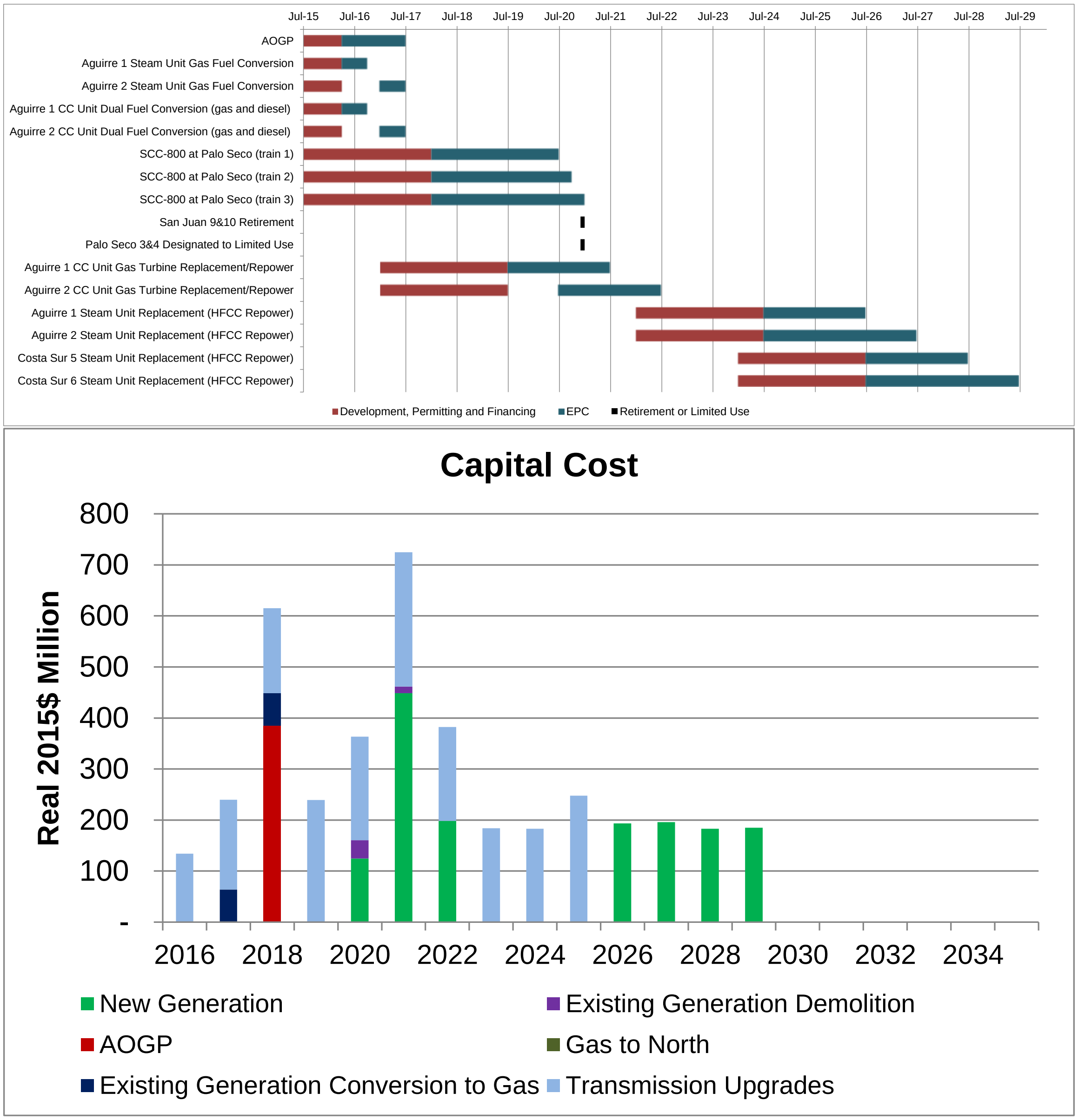
8.5 Portfolio 1 Future 4 (P1F4)

P1F4 key decisions include:

1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017.
2. New generation with diesel as primary fuel will be installed at Palo Seco by December 31, 2020.
3. Aguirre CC 1&2 repower by the end of 2021 and 2022 with natural gas as primary fuel.
4. Aguirre ST 1&2 HFCC repower by the end of 2026 and 2027 with natural gas as primary fuel.
5. Costa Sur 5&6 HFCC repower by the end of 2028 and 2029 with natural gas as primary fuel.
6. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

P1F4 timeline and capital costs are presented in Figure 8-17, indicating key portfolio retirement, fuel switching, and new build schedules. Given the high curtailment already evidenced in P1F1 and P1F3 results, Siemens concluded that P1F4 will incur even higher curtailments because of the lower net load assumptions in Future 4. This portfolio was not studied in detail.

Figure 8-17: P1F4 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

8.6 Portfolio 2 Future 1 (P2F1)

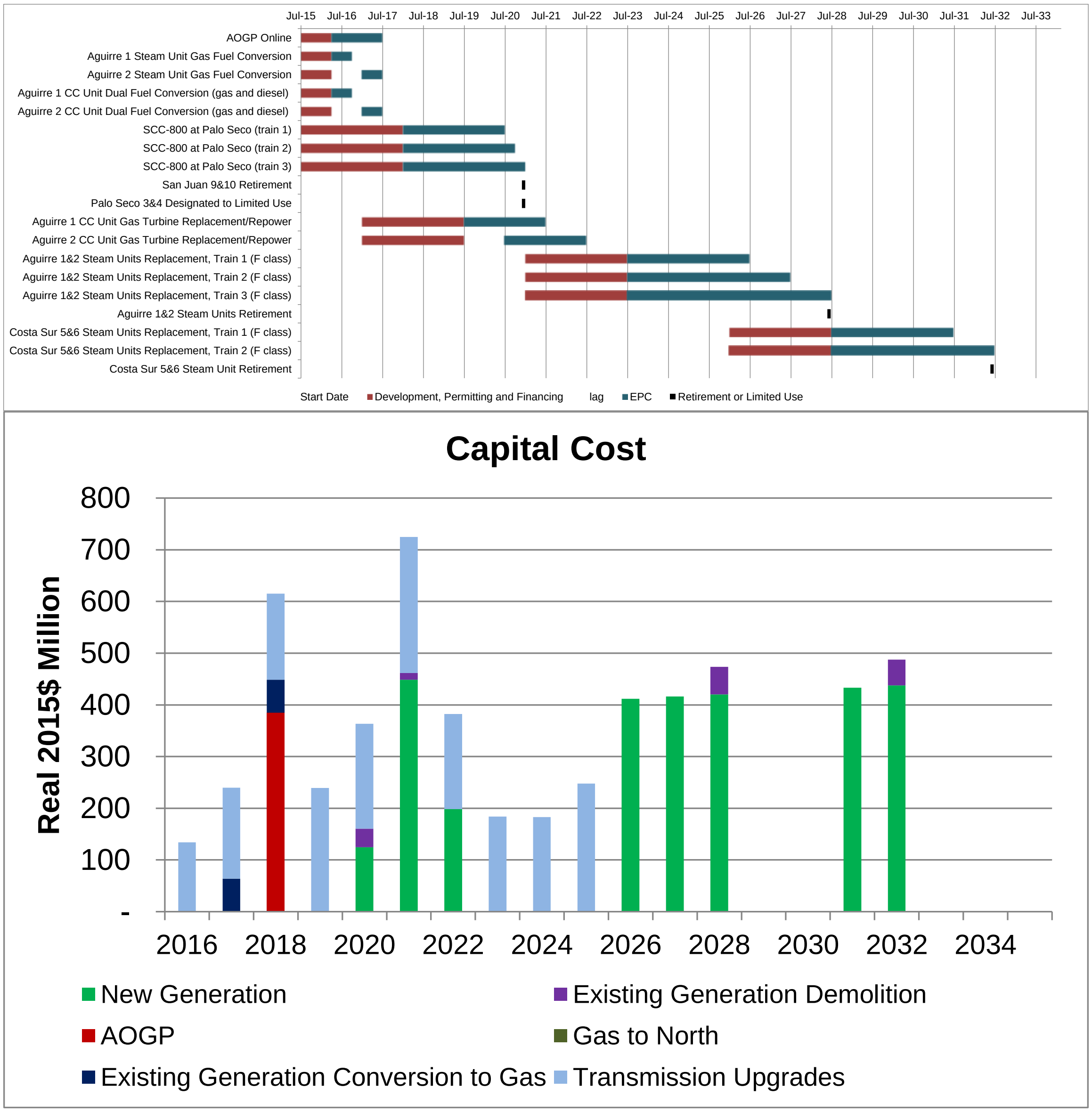
P2F1 key decisions include:

1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017.
2. New generation with diesel as primary fuel will be installed at Palo Seco by December 31, 2020.
3. Aguirre CC 1&2 repower by the end of fiscal year 2021 and 2022 with natural gas as primary fuel.

4. Aguirre ST 1&2 will be replaced with three small F Class combined cycle units that use natural gas as primary fuel at Aguirre site by the end of fiscal year 2026, 2027 and 2028.
5. Costa Sur 5&6 will be replaced by 2 small F Class combined cycle units that use natural gas as primary fuel by the end of fiscal year 2031 and 2032.
6. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

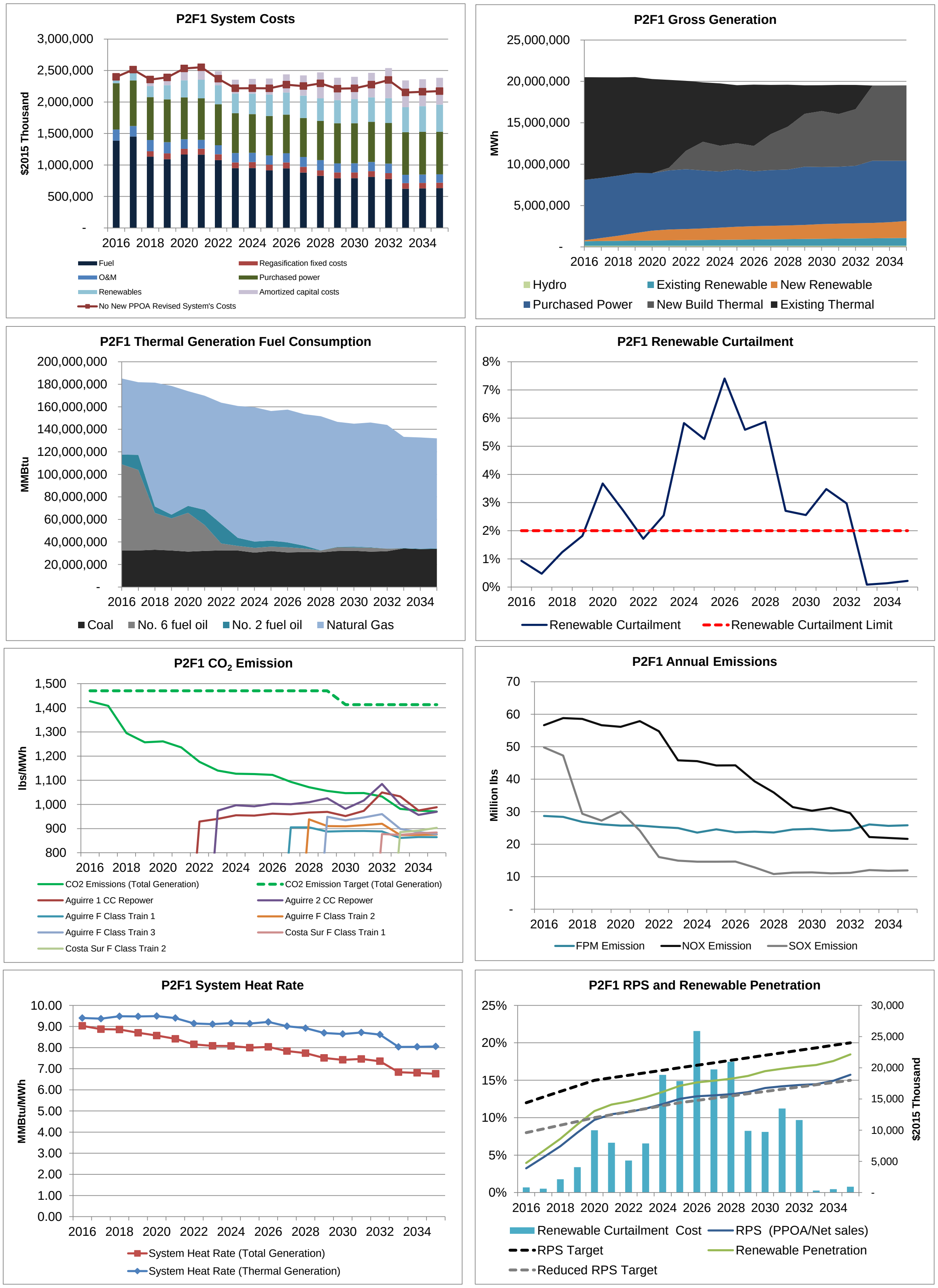
P2F1 timeline and capital costs are presented in Figure 8-18, indicating key portfolio retirement, fuel switching, and new build schedules. P2F1 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-19. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

Figure 8-18: P2F1 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

Figure 8-19: P2F1 Portfolio Metrics



Source: Siemens PTI, Pace Global, Pace Global

8.6.1 Cost Summary

The portfolio capital cost requirements are approximately $5.54 billion during 2016-2035, with $3.31 billion during 2016-2025 and $2.22 billion during 2026-2035. System costs average $2.43 billion per year over the forecast period. The present value of system costs aggregates to $26.93 billion over the 2016-2035 forecast period. The annual portfolio or system costs decrease over the forecast horizon by 0.03 percent per year on a real basis, suggesting that the system efficiency has improved, as evidenced by the system thermal generation heat rate reduction from 9,401 Btu/kWh in 2016 to 8,055 Btu/kWh in 2035.

The portfolio results show an average annual fuel costs reduction of 4.06 percent over the study period. The oil fired generation is replaced with natural gas fired generation and renewable generation over time. The biggest change in natural gas fired generation occurs in 2017 when AOGP comes online and Aguirre steam and combined cycle units undergo fuel conversion and start to burn natural gas.

Purchased power costs from AES and EcoEléctrica thermal plants are relatively constant over the forecast horizon as these units are base-loaded units with the lowest production costs and new unit additions and system improvements do not materially alter the dispatch profile of these facilities.

8.6.2 Environmental Compliance Summary

The portfolio results indicate compliance with the proposed Clean Power Plan requirements, but not in full compliance with the GHG New Source Standard as the Aguirre CC 1&2 may exceed the limits depending on its dispatch. Compliance should be achievable adjusting the dispatch of the units as in average there is compliance most of the time and the deviations observed can be managed by increasing the dispatch of these units at the expense of somewhat less optimal dispatch.

As shown in Figure 8-19, the portfolio meets the target emission rate in 2017 once AOGP becomes operational. The emission rate declines over time as the portfolio mix changes from oil fired generation capacity to new, more efficient natural gas fired generation capacity and greater renewable capacity. Total CO_2 emission rates expected to decline by 32 percent from 1,427 lb/MWh in 2016 to 971 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 18.46 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.6.3 Operational Performance Summary

In the near and long term, day-time renewable curtailments are within the two percent threshold. However, the curtailments exceed the threshold as both utility scale and distributed solar penetration increases during 2020-2032. The portfolio performs well in terms of reliability with zero loss of load hours in most years except 2021 and 2022. As before if the existing GT at the Aguirre CC that will be repowered and Cambalache 1 were maintained available there would be zero LOLH. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

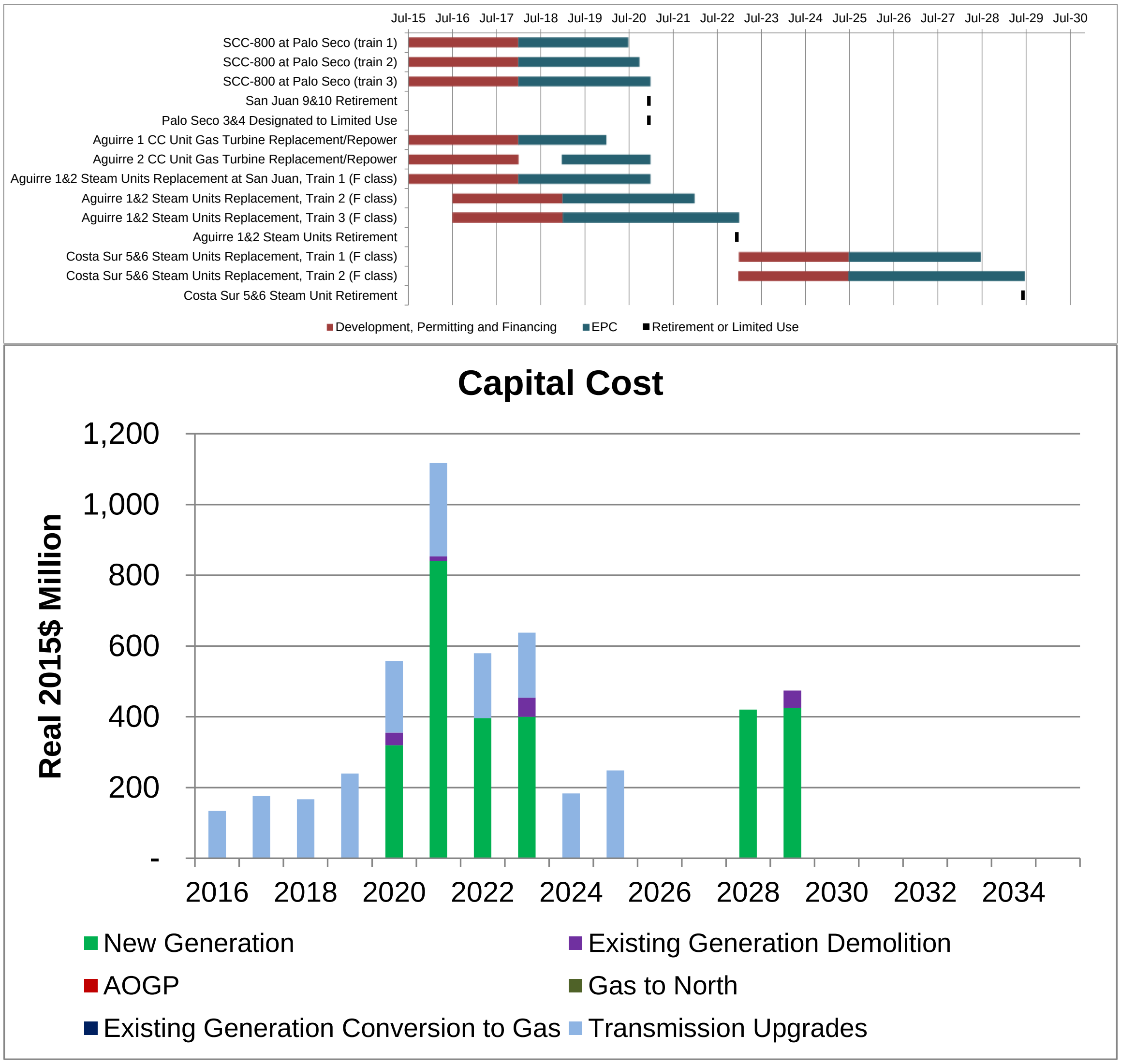
8.7 Portfolio 2 Future 2 (P2F2)

P2F2 key decisions include:

1. New generation with diesel as primary fuel will be installed at Palo Seco by December 31, 2020.
2. Aguirre CC 1&2 repower by the end of fiscal year 2019 and 2020 with diesel as primary fuel.
3. Aguirre ST 1&2 will be replaced with one small F Class combined cycle unit at San Juan site by December 31th 2020 and two small combined cycle units at Aguirre site by December 31th 2021 and 2022 with diesel as the primary fuel for three new small CC units.
4. Costa Sur 5&6 will be replaced with 2 small F Class combined cycle units with natural gas as primary fuel at Costa Sur site by the end of fiscal year 2028 and 2029.
5. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

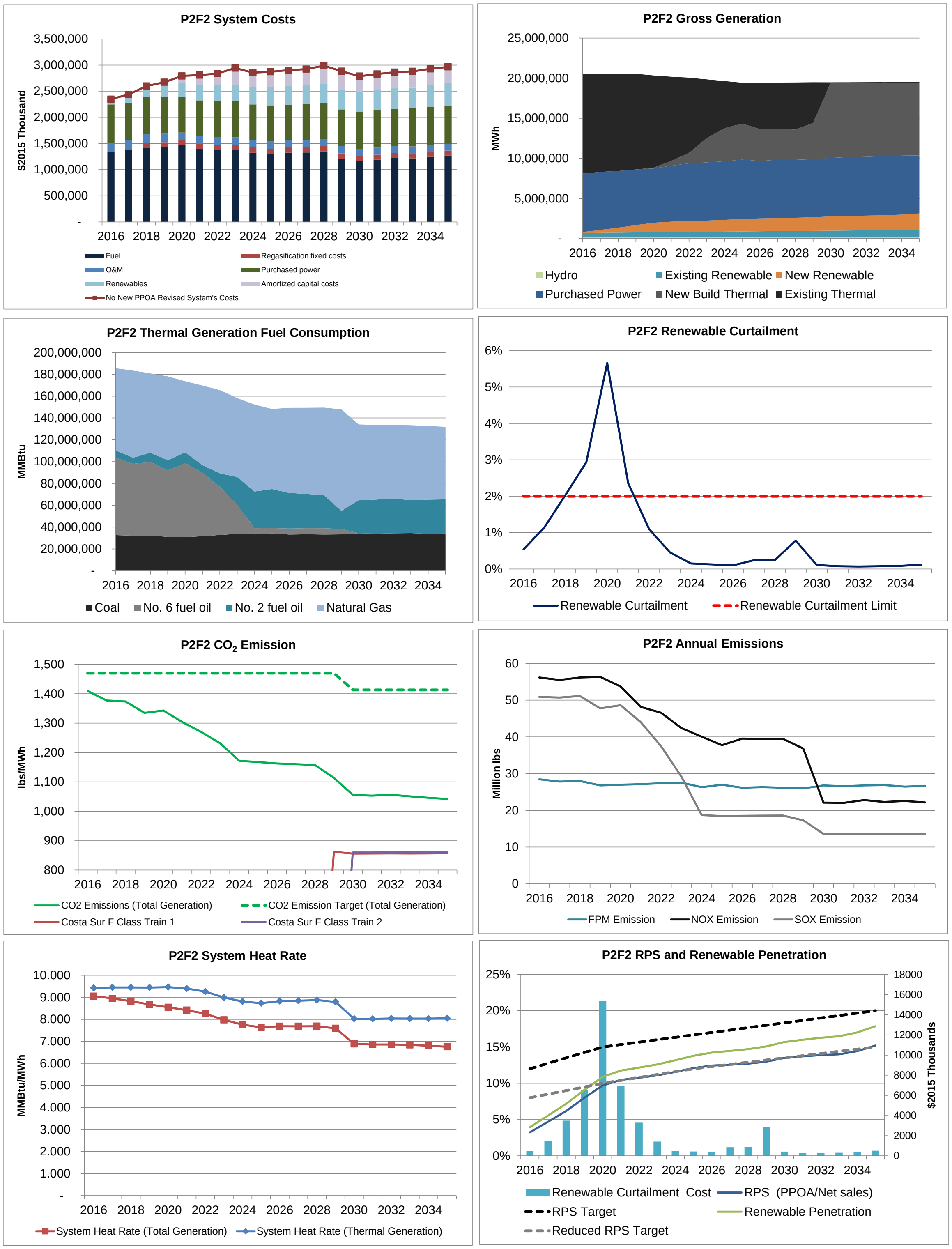
P2F2 timeline and capital costs are presented in Figure 8-20, indicating key portfolio retirement, fuel switching, and new build schedules. P2F2 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-21. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

Figure 8-20: P2F2 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

Figure 8-21: P2F2 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.7.1 Cost Summary

The portfolio capital cost requirements are close to $4.93 billion during 2016-2035, with $4.04 billion during 2016-2025 and $0.89 billion during 2026-2035. System costs average $2.77 billion per year over the forecast period. The present value of system costs aggregates to $30.02 billion over the 2016-2035 forecast period. The annual portfolio or system costs increase over the forecast horizon by 1.22 percent per year on a real basis, which is significantly higher than P2F1 which has gas available in the South. The system thermal generation heat rate is expected to decline from 9,425 Btu/kWh in 2016 to 8,048 Btu/kWh[54] in 2035. The annual fuel costs decreases by an average of 0.27 percent per year during the study period.

8.7.2 Environmental Compliance Summary

The portfolio results indicate compliance with the proposed Clean Power Plan requirements and the GHG New Source Standard (for the new Costa Sur CC units). The NOx, SOx, CO_2 and FPM emissions decline over time. For example, total CO_2 emission rates are expected to decline by 26 percent from 1,409 lb/MWh in 2016 to 1,042 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 17.86 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.7.3 Operational Performance Summary

Due to accelerated new builds, the day-time renewable curtailments are within the two percent threshold for all the years except 2019 to 2021. The portfolio performs well in terms of reliability and there are no LOLH for the period under analysis. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

8.8 Portfolio 2 Future 3 (P2F3)

P2F3 key decisions include:

1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017.
2. New generation will be installed at Palo Seco site by December 31, 2020. New generation will burn diesel initially and switch to natural gas when gas to North is available by July 1st 2022.
3. Aguirre CC 1&2 repower by the end of fiscal year 2021 and 2022 with natural gas as primary fuel.
4. Aguirre ST 1&2 will be replaced with one small F Class combined cycle unit at San Juan site by the end of fiscal year 2023 and two small F Class combined

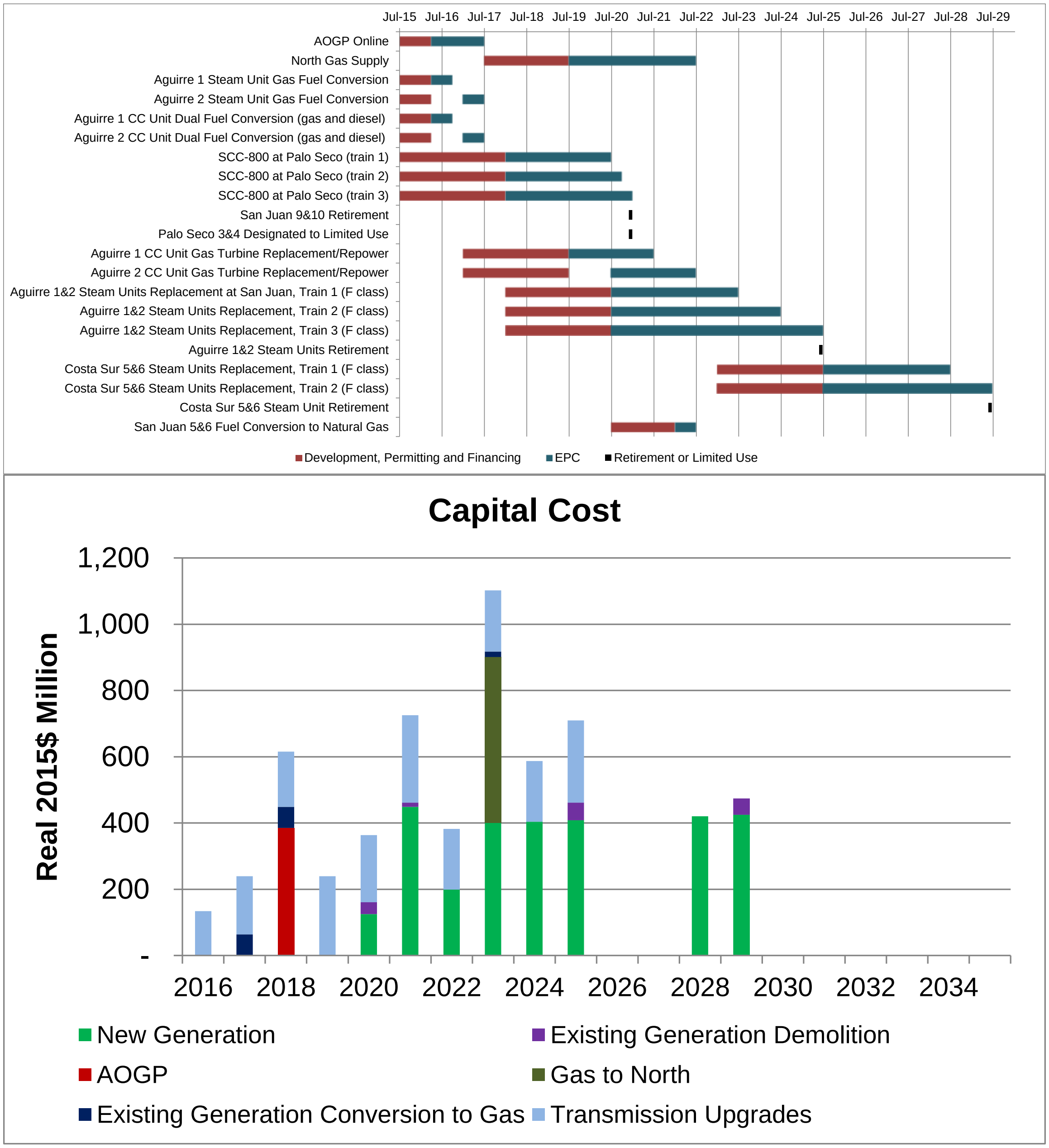
[54] Close to a heat rate corresponding to a combined cycle plant.

cycle units at Aguirre site by the end of fiscal year 2024 and 2025 with natural gas as the primary fuel for three new small CC units.

5. Costa Sur 5&6 will be replaced with two small F Class combined cycle units with natural gas as primary fuel by the end of fiscal year 2028 and 2029.
6. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

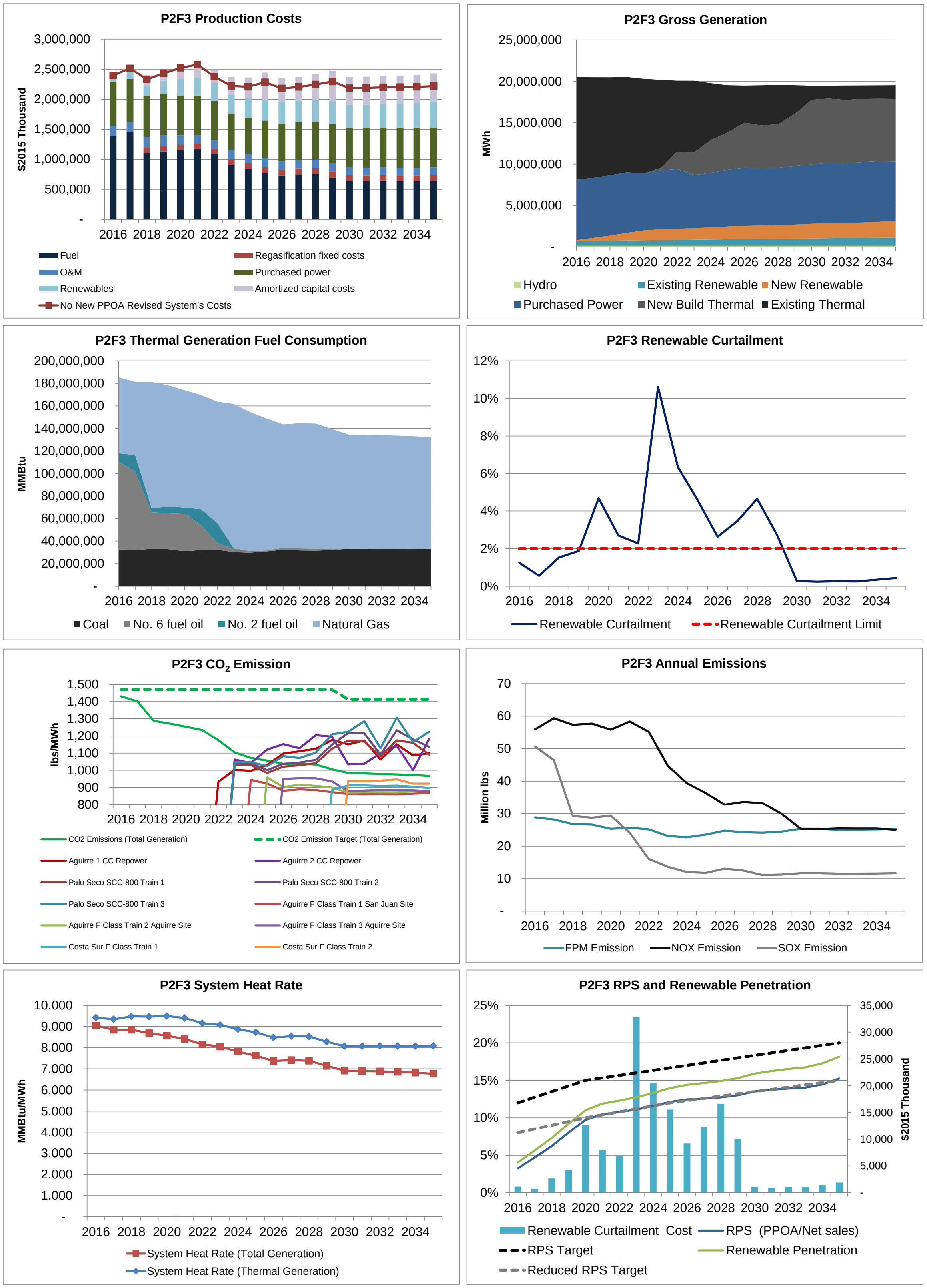
P2F3 timeline and capital costs are presented in Figure 8-22, indicating key portfolio retirement, fuel switching, and new build schedules. P2F2 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-23. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

Figure 8-22: P2F3 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

Figure 8-23: P2F3 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.8.1 Cost Summary

The portfolio capital cost requirements are close to $6 billion during 2016-2035, with $5.10 billion during 2016-2025 and $0.89 billion during 2026-2035. System costs average $2.42 billion per year over the forecast period. The present value of system costs aggregates to $26.9 billion over the 2016-2035 forecast period. The annual portfolio or system costs increase over the forecast horizon by 0.07 percent per year on a real basis, despite a reduction in fuel costs by 3.98 percent per year. The system thermal generation heat rate is expected to decline from 9,422 Btu/kWh in 2016 to 8,085 Btu/kWh[55] in 2035.

8.8.2 Environmental Compliance Summary

The portfolio results indicate compliance with the proposed Clean Power Plan requirements, but not in compliance with the GHG New Source Standard. The portfolio results indicate that the SCC 800 unit at Palo Seco may have difficulty to comply with the Clean Power Plan requirements in certain years when the dispatch is low and the fuel consumptions are high per MWh delivered due to the double impact of frequent starts and the relatively high heat rate at minimum output. The Aguirre CC 1&2 would also show incompliance with the standard and in their case this implies that their dispatch would have to be increased introducing some inefficiencies in the dispatch.

Overall, the CO_2 emission rate declines over time as the portfolio mix changes from oil fired generation capacity to new, more efficient natural gas fired generation capacity and greater renewable capacity. Total CO_2 emissions are expected to decline by 32 percent from 1,430 lb/MWh in 2016 to 967 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 18.14 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.8.3 Operational Performance Summary

In the near and long term, day-time renewable curtailments are within the two percent threshold. However, during 2019 - 2028, the curtailments exceed the threshold as both utility scale and distributed solar penetration increases and the new generations have not yet come on line. The portfolio performs well in terms of reliability with zero loss of load hours in most years and as before with four 50 MW units of the Aguirre CC that is repowered and Cambalache 1 available there would be no LOLH. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

8.9 Portfolio 2 Future 4 (P2F4)

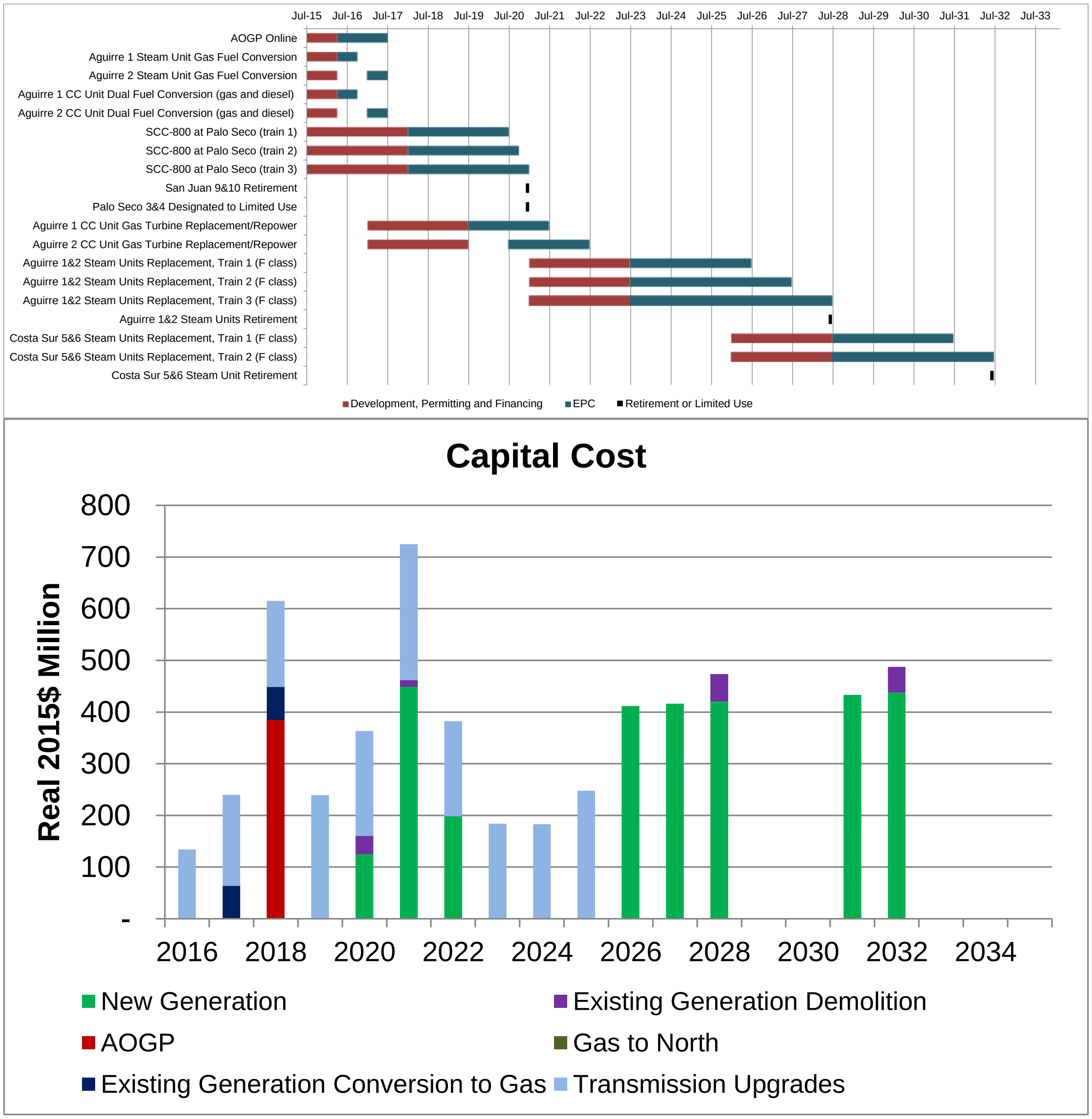
P2F4 key decisions include:

[55] Close to a heat rate corresponding to a combined cycle plant.

1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017.
2. New generation with diesel as primary fuel will be installed at Palo Seco by December 31, 2020.
3. Aguirre CC 1&2 repower by the end of fiscal year 2021 and 2022 with natural gas as primary fuel.
4. Aguirre ST 1&2 will be replaced with three small F Class combined cycle units that use natural gas as primary fuel at Aguirre site by the end of fiscal year 2026, 2027 and 2028.
5. Costa Sur 5&6 will be replaced by 2 small F Class combined cycle units that use natural gas as primary fuel by the end of fiscal year 2031 and 2032.
6. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

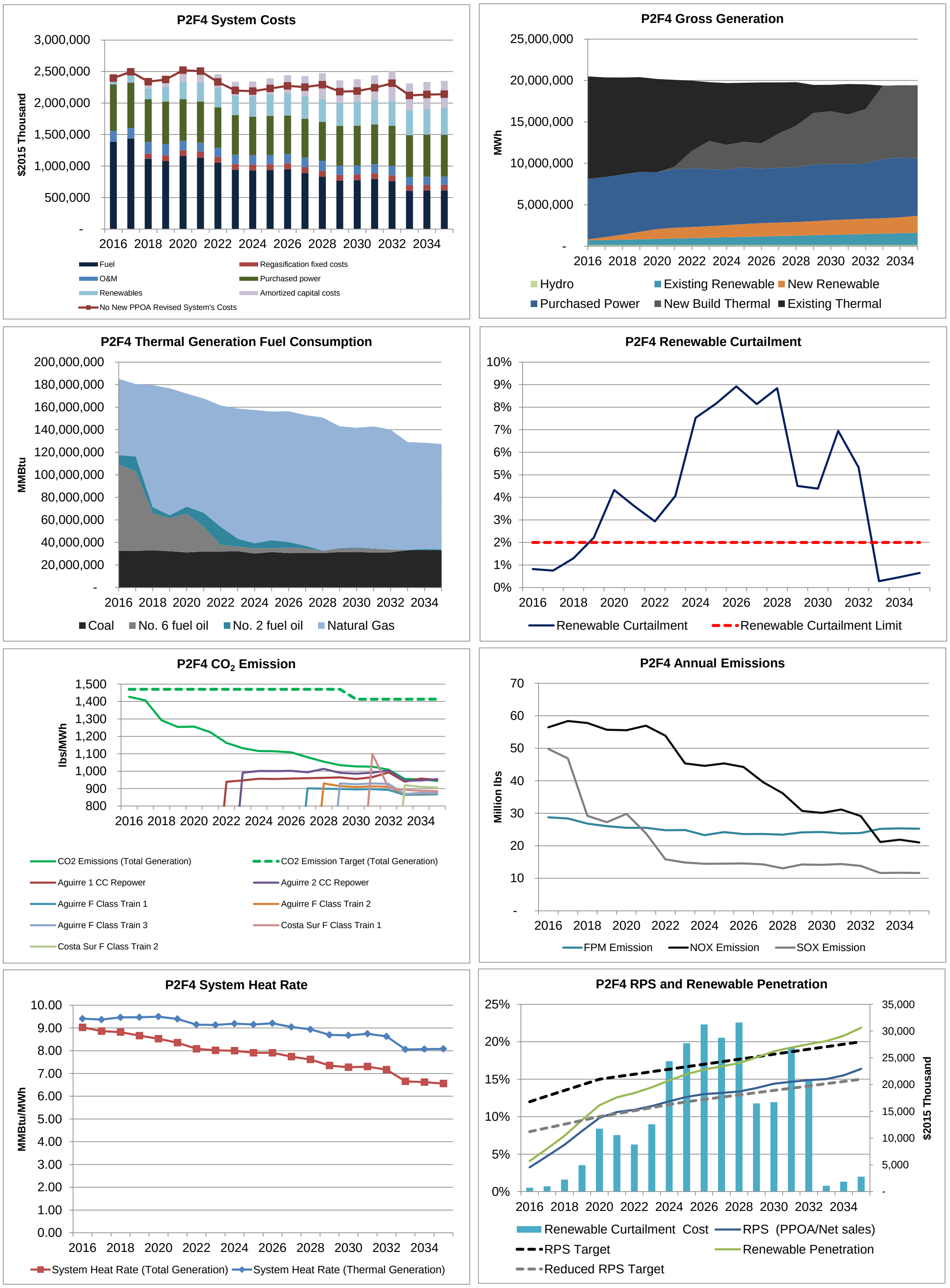
P2F4 timeline and capital costs are presented in Figure 8-24, indicating key portfolio retirement, fuel switching, and new build schedules. P2F4 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-25. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

Figure 8-24: P2F4 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

Figure 8-25: P2F4 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.9.1 Cost Summary

The portfolio capital cost requirements are close to \$5.54 billion during 2016-2035, with \$3.31 billion during 2016-2025 and \$2.22 billion during 2026-2035. System costs average \$2.41 billion per year over the forecast period, showing a 0.1 percent reduction per year over the study period. The present value of system costs aggregates to \$26.76 billion over the 2016-2035 forecast period. The system thermal generation heat rate is expected to decline from 9,408 Btu/kWh in 2016 to 8,080 Btu/kWh[56] in 2035.

8.9.2 Environmental Compliance Summary

The portfolio results indicate compliance with the proposed Clean Power Plan requirements, but marginal compliance with the GHG New Source Standard due to the same issues with the lower dispatch of the Aguirre CC 2 and could be fixed with a small adjustment of the dispatch levels. The emission rate declines over time as the portfolio mix changes from oil fired generation capacity to new, more efficient natural gas fired generation capacity and greater renewable capacity. Total CO_2 emissions are expected to decline by 34 percent from 1,427 lb/MWh in 2016 to 944 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 21.87 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.9.3 Operational Performance Summary

In the near and long term, day-time renewable curtailments are within the two percent threshold. However, during 2019 - 2028, the curtailments exceed the threshold as both utility scale and distributed solar penetration increases and the new generations have not yet come on line. The portfolio performs well in terms of reliability with zero loss of load hours in most years except 2016, 2020, 2021, 2022 and 2024. In this case with four 50 MW units of the Aguirre CC that is repowered and Cambalache 1 available there would be only 2 LOLH in the entire period. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

8.10 Portfolio 3 Future 1 (P3F1)

P3F1 key decisions include:

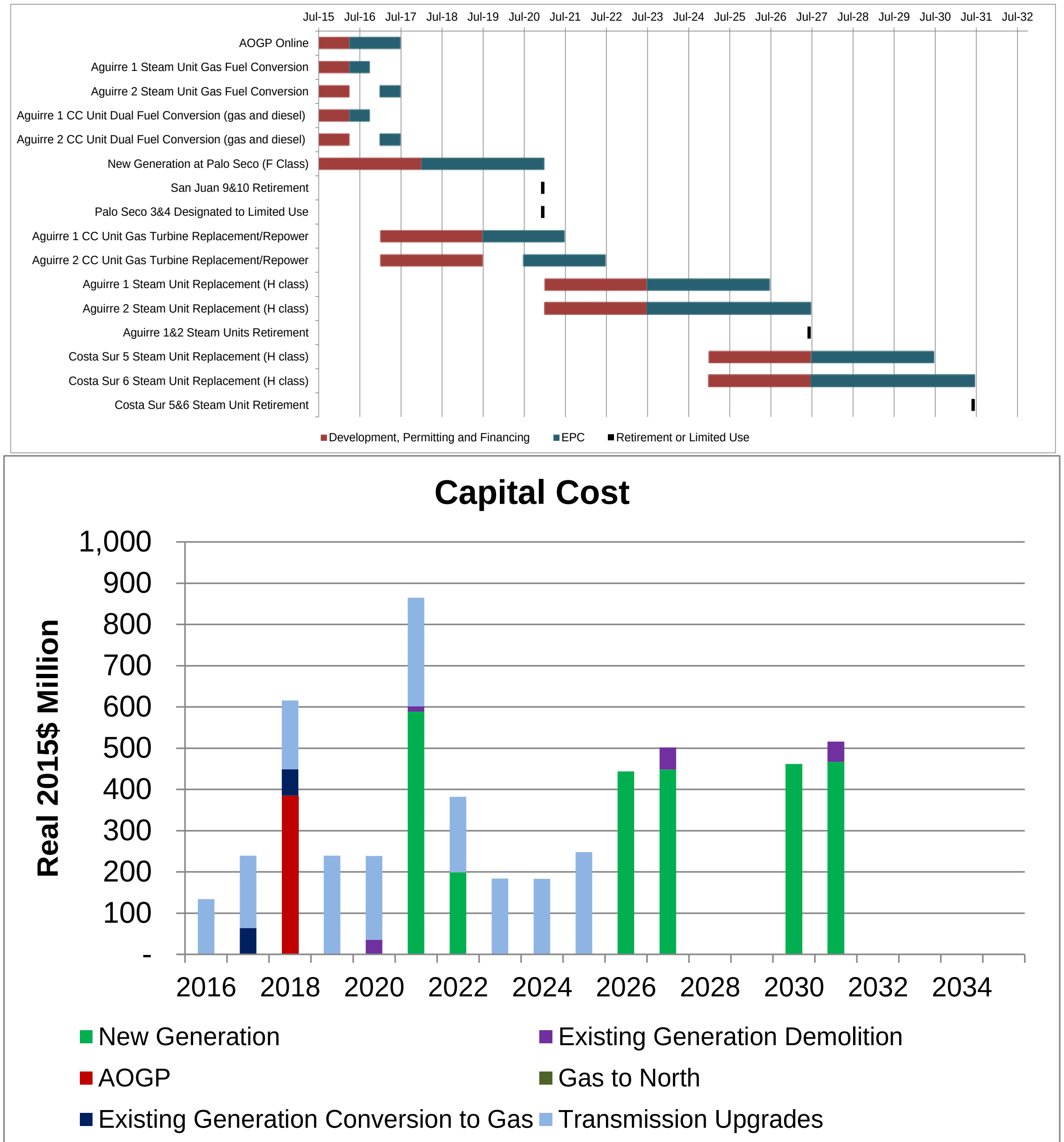
1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017;
2. New generation that use diesel as primary fuel will be installed at Palo Seco by December 31, 2020.
3. Aguirre CC 1&2 repower by the end of fiscal year 2021 and 2022 with natural gas as primary fuel.

[56] Close to a heat rate corresponding to a combined cycle plant.

4. Aguirre ST 1&2 will be replaced with two large H Class combined cycle units with natural gas as primary fuel by the end of fiscal year 2026 and 2027 at Aguirre site.
5. Costa Sur 5&6 will be replaced with two large H Class combined cycle units with natural gas as primary fuel by the end of fiscal year 2030 and 2031 at Costa Sur site.
6. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

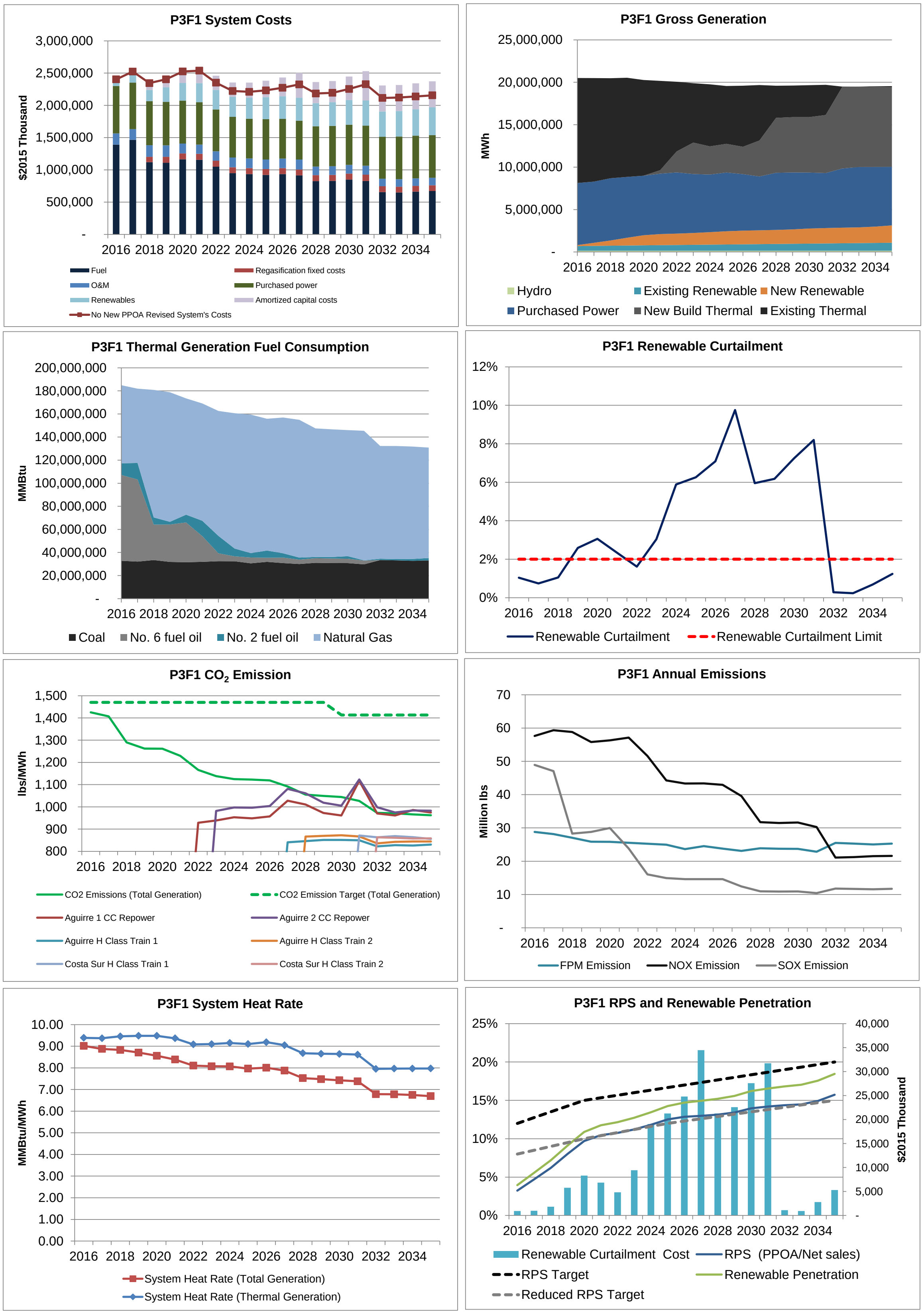
P3F1 timeline and capital costs are presented in Figure 8-26, indicating key portfolio retirement, fuel switching, and new build schedules. P3F1 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-27. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

Figure 8-26: P3F1 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

Figure 8-27: P3F1 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.10.1 Cost Summary

The portfolio capital cost requirements are close to $5.25 billion during 2016-2035, with $3.33 billion during 2016-2025 and $1.92 billion during 2026-2035. System costs average $2.42 billion per year over the forecast period. The present value of system costs aggregates to $26.84 billion over the 2016-2035 forecast period. The annual portfolio or system costs slightly decrease over the forecast horizon by 0.07 percent per year on a real basis. The system efficiency improves significantly, with system thermal generation heat rate declining from 9,389 Btu/kWh in 2016 to 7,972 Btu/kWh in 2035. The annual fuel costs decrease by an average 3.75 percent per year over the study period.

Purchased power costs from AES and EcoEléctrica thermal plants are relatively constant over the forecast horizon as these units are base-loaded units with the lowest production costs and new unit additions and system improvements do not materially alter the dispatch profile of these facilities.

8.10.2 Environmental Compliance Summary

The portfolio results indicate compliance with the proposed Clean Power Plan requirements, but not in compliance with the GHG New Source Standard when individual units are considered, in particular the issue was observed with the Aguirre CC 1&2 for the same reasons indicated earlier, low dispatch levels and this could be addressed by adjusting the dispatch by for example including this limitation as a restriction in the operating cost optimization procedure.

As shown in Figure 8-27, the portfolio meets the target emission rate in 2017 once AOGP becomes operational. The emission rate declines over time as the portfolio mix changes from oil fired generation capacity to new, more efficient natural gas fired generation capacity and greater renewable capacity. Total CO_2 emissions are expected to decline by 32 percent from 1,425 lb/MWh in 2016 to 962 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 18.46 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.10.3 Operational Performance Summary

In the near and long term, the day-time renewable curtailments are less than two percent, but curtailments during 2019 2031 are significant as both utility scale and distributed solar penetration increases. The portfolio performs well in terms of reliability with zero loss of load hours in most years and always at or below the threshold of 4 hours. As before with four 50 MW units of the Aguirre CC and Cambalache 1 available there would be no LOLH. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

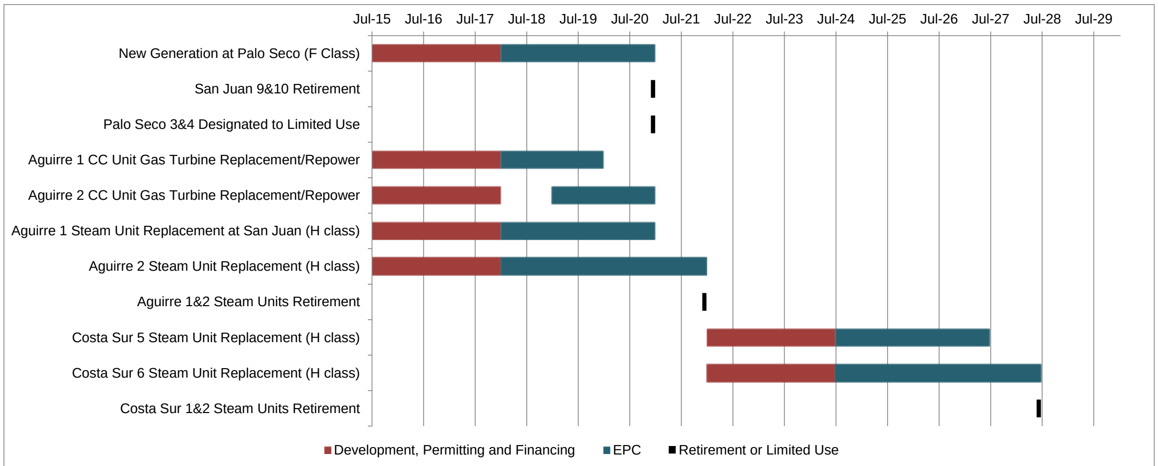
8.11 Portfolio 3 Future 2 (P3F2)

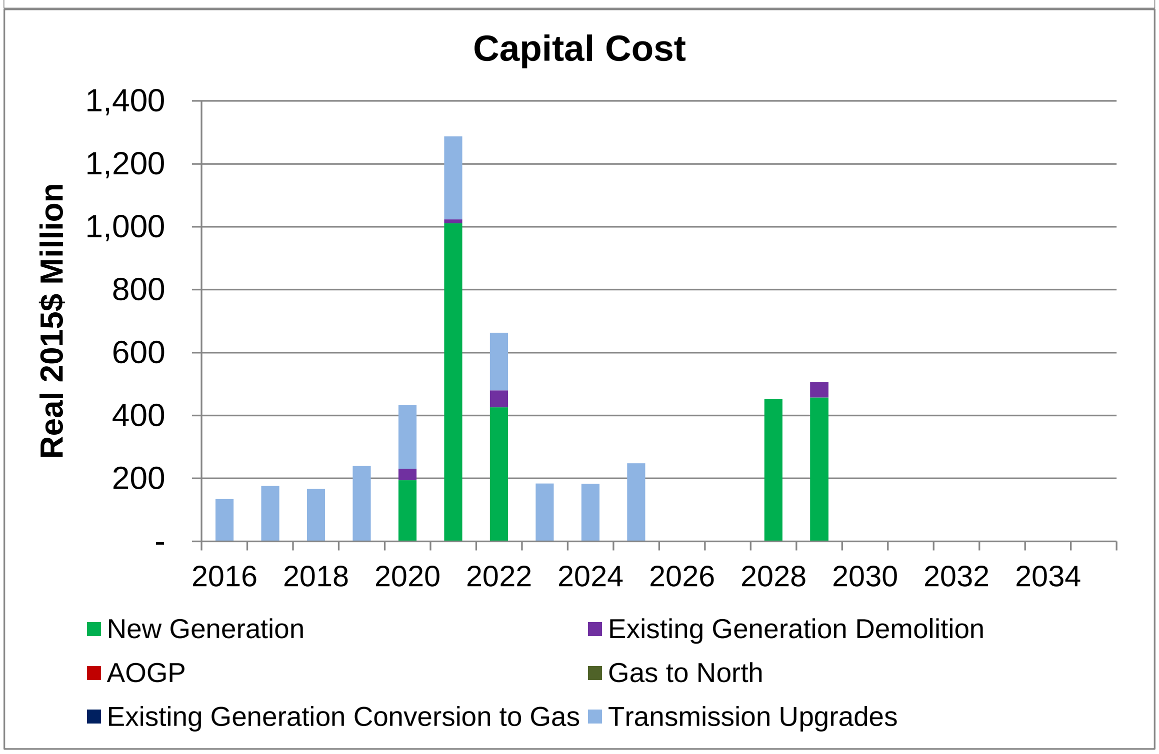
P3F2 key decisions include:

1. New generation that use diesel as primary fuel will be installed at Palo Seco by December 31, 2020.
2. Aguirre CC 1&2 repower by the end of fiscal year 2021 and 2022 with diesel as primary fuel.
3. Aguirre ST 1&2 will be replaced with one large H Class combined cycle unit at San Juan site by December 31st 2020, and one H Class combined cycle unit at Aguirre site by December 31st 2021. Both units use diesel as primary fuel.
4. Costa Sur 5&6 will be replaced with two large H Class combined cycle units that use natural gas as primary fuel by the end of fiscal year 2027 and 2028.
5. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

P3F2 timeline and capital costs are presented in Figure 8-28, indicating key portfolio retirement, fuel switching, and new build schedules. P3F2 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-29. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

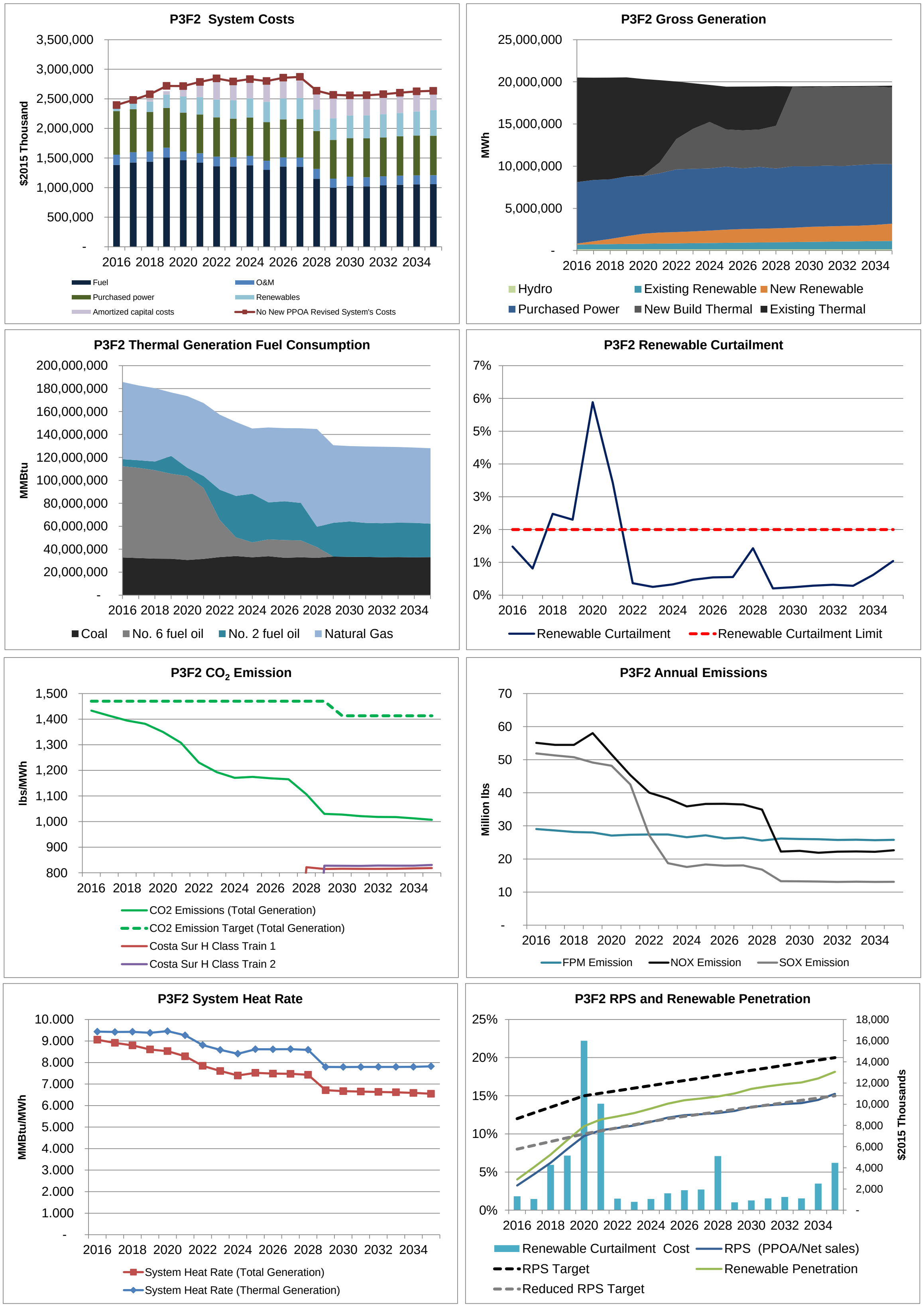
Figure 8-28: P3F2 Schedules and Capital Costs





Source: Siemens PTI, Pace Global

Figure 8-29: P3F2 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.11.1 Cost Summary

The portfolio capital cost requirements are close to $4.67 billion during 2016-2035, with $3.72 billion during 2016-2025 and $0.96 billion during 2026-2035. System costs average $2.66 billion per year over the forecast period. The present value of system costs aggregates to $29.3 billion over the 2016-2035 forecast period. The annual portfolio or system costs increase over the forecast horizon by 0.61 percent per year on a real basis, which is significantly higher than P3F1 which has gas available in the South. The system thermal generation heat rate is expected to decline from 9,435 Btu/kWh in 2016 to 7,823 Btu/kWh in 2035.

8.11.2 Environmental Compliance Summary

The portfolio results indicate compliance with the Clean Power Plan requirements and the GHG New Source Standard. The NOx, SOx, CO_2 and FPM emissions decline over time. For example, total CO_2 emissions are expected to decline by 30 percent from 1,433 lb/MWh in 2016 to 1,007 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 18.14 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.11.3 Operational Performance Summary

Due to accelerated new builds, the day-time renewable curtailments are within the two percent threshold for all the years except 2018 - 2021. The portfolio performs well in terms of reliability with zero loss of load hours in most years and the LOLH are at or below the threshold of 4 hours. Moreover four 50 MW units of the Aguirre CC and Cambalache 1 available there would be no LOLH. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

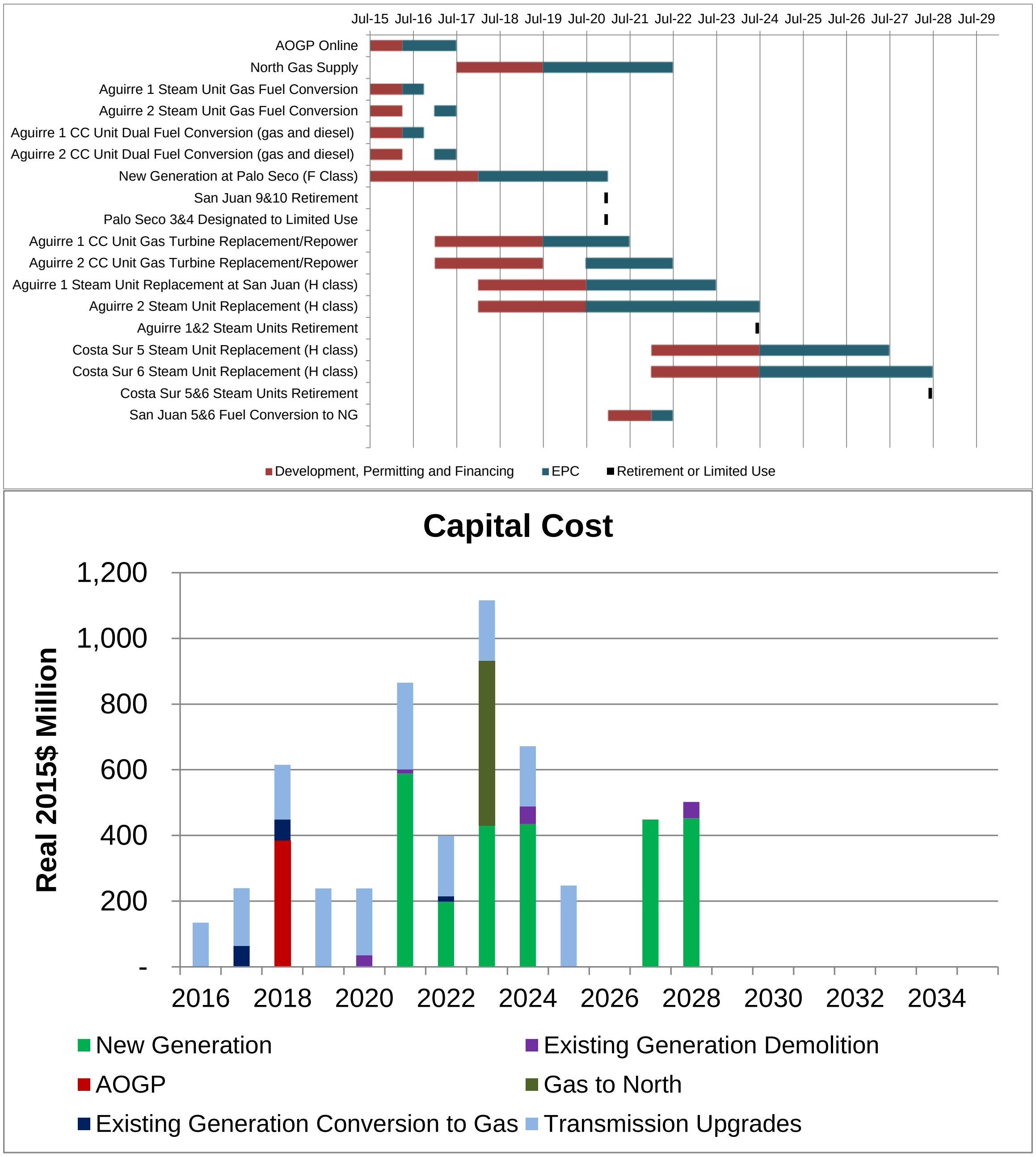
8.12 Portfolio 3 Future 3 (P3F3)

P3F3 key decisions include:

1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017.
2. New generation will be installed at Palo Seco site by December 31, 2020. New generation will burn diesel initially and switch to natural gas when gas to North is available by July 1, 2022.
3. Aguirre CC 1&2 repower be the end of fiscal year 2021 and 2022 with natural gas as primary fuel.
4. Aguirre ST 1&2 will be replaced with one large H Class combined cycle unit at San Juan site by the end of fiscal year 2023, and one H Class combined cycle unit at Aguirre site by the end of fiscal year 2024. Both units use natural gas as primary fuel.
5. Costa Sur 5&6 will be replaced with two large H Class combined cycle units that use natural gas as primary fuel by the end of fiscal year 2027 and 2028.
6. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

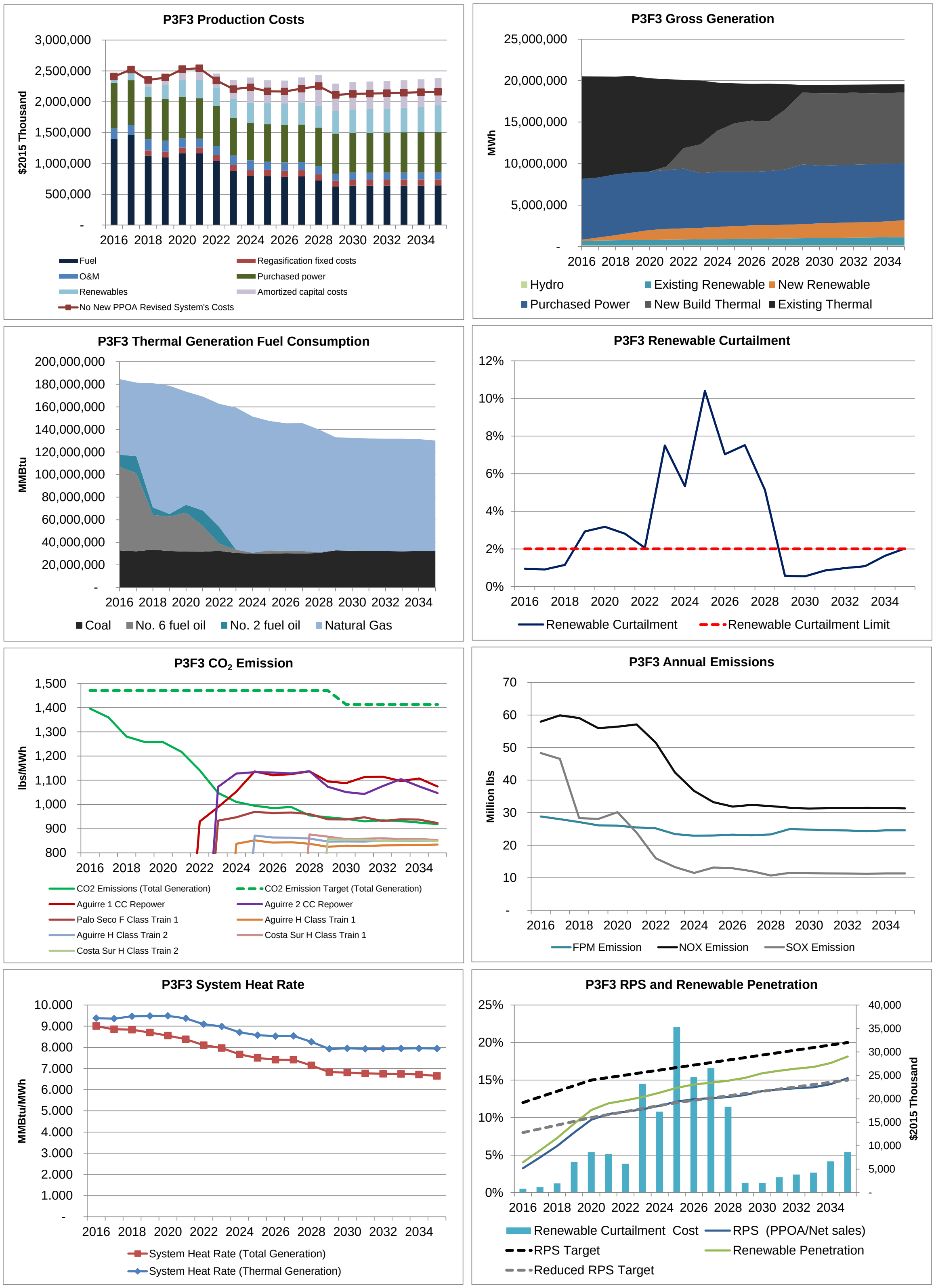
P3F3 timeline and capital costs are presented in Figure 8-30, indicating key portfolio retirement, fuel switching, and new build schedules. P3F3 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-31. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

Figure 8-30: P3F3 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

Figure 8-31: P3F3 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.12.1 Cost Summary

The portfolio capital cost requirements are close to $5.72 billion during 2016-2035, with $4.77 billion during 2016-2025 and $0.95 billion during 2026-2035. System costs average $2.39 billion per year over the forecast period. The present value of system costs aggregates to $26.66 billion over the 2016-2035 forecast period. The annual portfolio or system costs decreases by 0.06 percent per year during the study period. The system efficiency improves significantly, with system thermal generation heat rate declining from 9,279 Btu/kWh in 2016 to 7,943 Btu/kWh in 2035.

The portfolio results show a significant decline in oil consumption and generation from oil fired resources. The oil fired generation is replaced with natural gas fired generation and renewable generation over time. The biggest change in natural gas fired generation occurs in 2017 when AOGP comes online and Aguirre steam and combined cycle units undergo fuel conversion and start to burn natural gas. When gas to the North becomes available in 2023, the system gas consumption goes through another increase. The annual fuel costs decrease by an average of 4 percent per year over the study period.

Purchased power costs from AES and EcoEléctrica thermal plants are relatively constant over the forecast horizon as these units are base-loaded units with the lowest production costs and new unit additions and system improvements do not materially alter the dispatch profile of these facilities.

8.12.2 Environmental Compliance Summary

The portfolio results indicate compliance with the Clean Power Plan requirements, but not the GHG New Source Standard, due to the same issues with low dispatch of the Aguirre CC 1&2 that are specially pronounced in Future 3 due to the availability of gas in the North to the new efficient units at Palo Seco and San Juan. This can be corrected by adjusting the dispatch and in this case it would result in increased production costs.

The emission rate declines over time as the portfolio mix changes from oil fired generation capacity to new, more efficient natural gas fired generation capacity and greater renewable capacity. Total CO_2 emissions are expected to decline by 34 percent from 1,396 lb/MWh in 2016 to 919 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 18.14 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.12.3 Operational Performance Summary

The day-time renewable curtailments in the near and long term are within the two percent limit, but range four to nine percent during 2020 - 2028 as both utility scale and distributed solar penetration increases. The portfolio performs well in terms of reliability with zero loss of load hours in most years and very similar to the other realization of P3 presented above. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

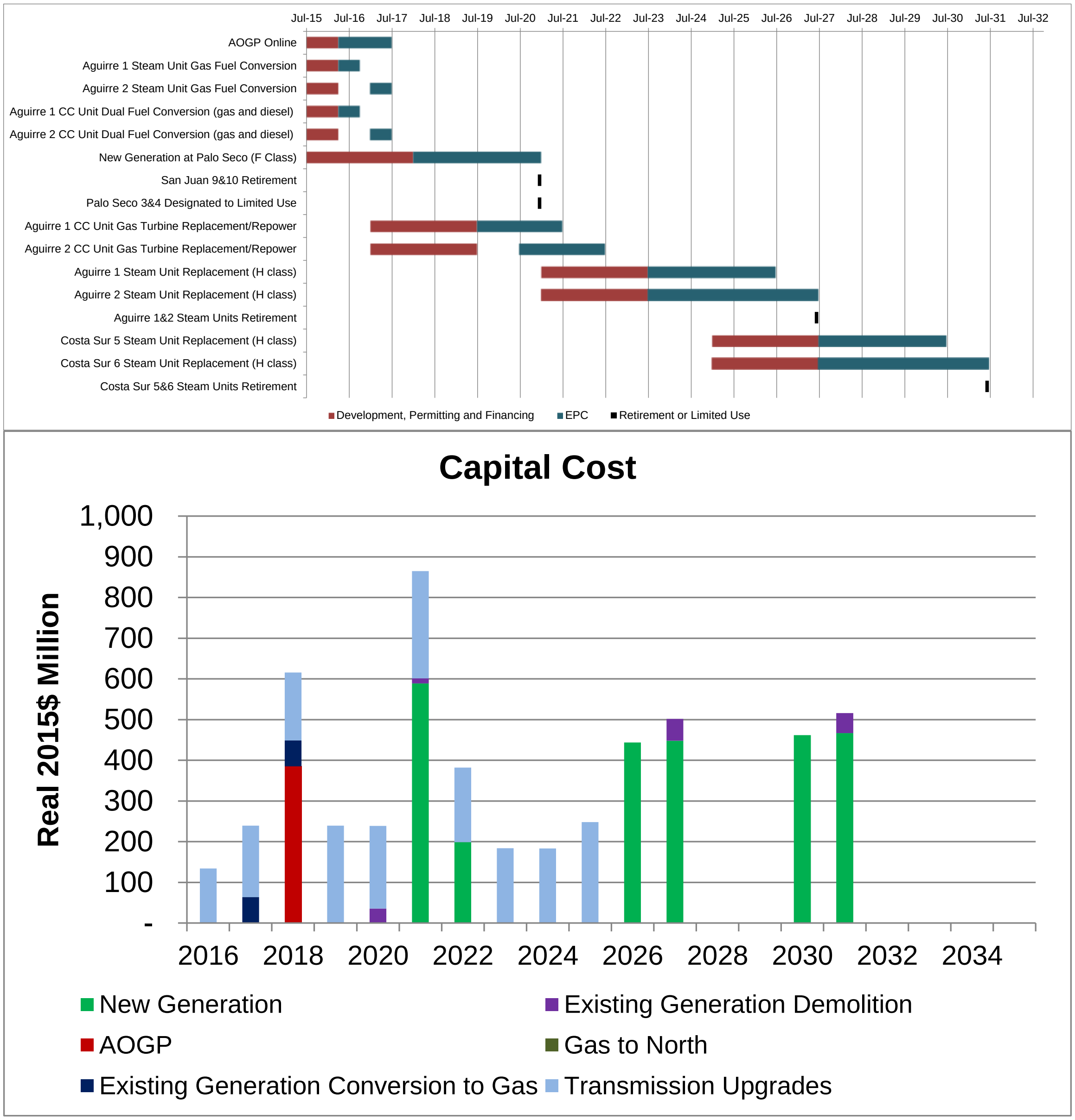
8.13 Portfolio 3 Future 4 (P3F4)

P3F4 key decisions include:

1. Aguirre ST and CC units' fuel conversion after AOGP comes online by July 1, 2017.
2. New generation that use diesel as primary fuel will be installed at Palo Seco by December 31, 2020.
3. Aguirre CC 1&2 repower by the end of fiscal year 2021 and 2022 with natural gas as primary fuel.
4. Aguirre ST 1&2 will be replaced with two large H Class combined cycle units with natural gas as primary fuel by the end of fiscal year 2026 and 2027 at Aguirre site.
5. Costa Sur 5&6 will be replaced with two large H Class combined cycle units with natural gas as primary fuel by the end of fiscal year 2030 and 2031 at Costa Sur site.
6. San Juan 9&10 and Palo Seco 3&4 will be either retired or designated to limited use by December 31, 2020.

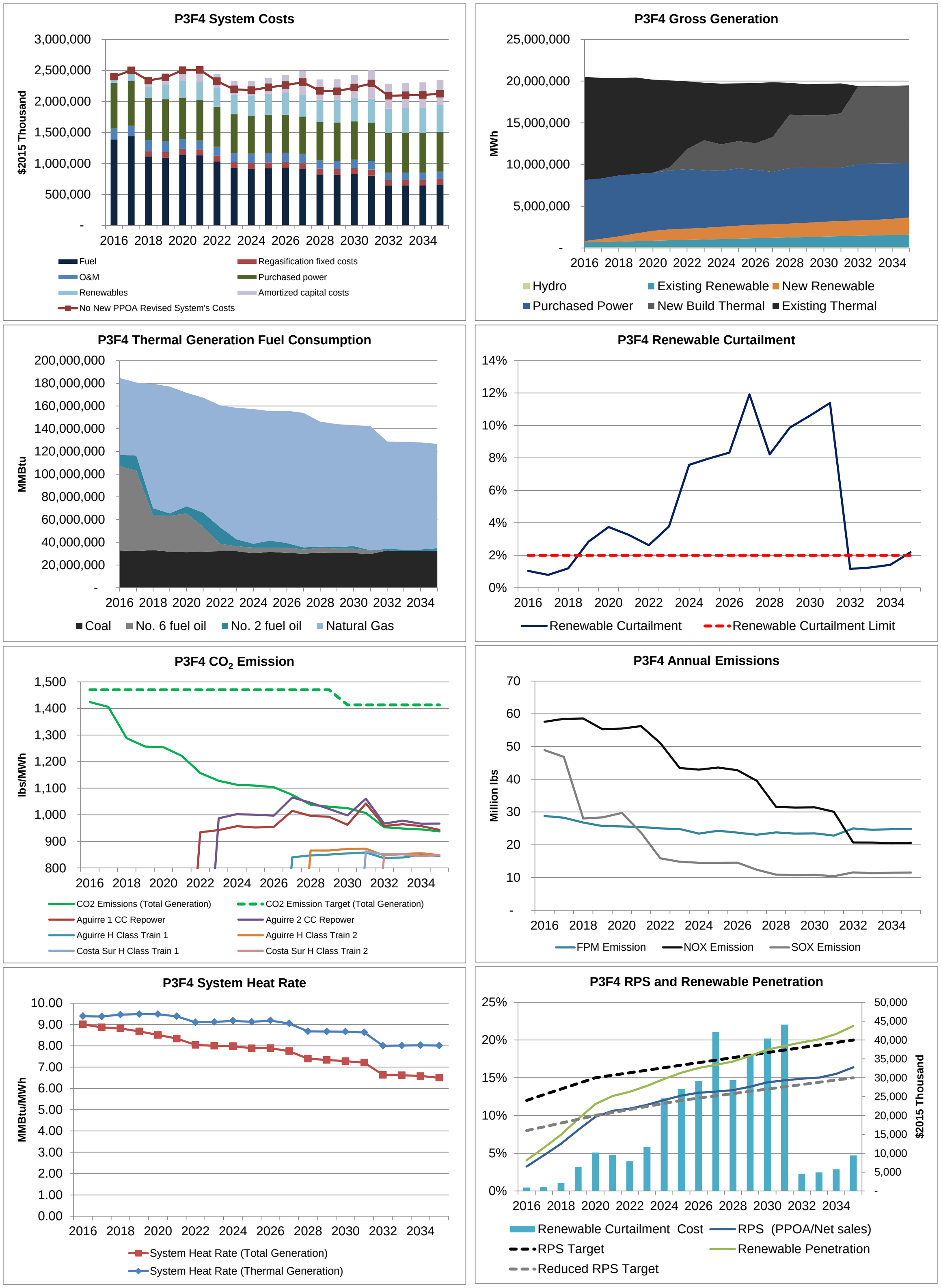
P3F4 timeline and capital costs are presented in Figure 8-32, indicating key portfolio retirement, fuel switching, and new build schedules. P3F4 key cost, generation, fuel consumption, operation and environmental metrics are presented in Figure 8-33. More detailed results and the data for the metrics are presented in Appendixes C, D, and E.

Figure 8-32: P3F4 Schedules and Capital Costs



Source: Siemens PTI, Pace Global

Figure 8-33: P3F4 Portfolio Metrics



Source: Siemens PTI, Pace Global

8.13.1 Cost Summary

The portfolio capital cost requirements are close to $5.25 billion during 2016-2035, with $3.33 billion during 2016-2025 and $1.92 billion during 2026-2035. System costs average $2.40 billion per year over the forecast period. The present value of system costs aggregates to $26.65 billion over the 2016-2035 forecast period. The annual portfolio or system costs decrease over the forecast horizon by 0.13 percent per year on a real basis. The system efficiency improves significantly, with system thermal generation heat rate declining from 9,389 Btu/kWh in 2016 to 8,009 Btu/kWh in 2035.

Purchased power costs from AES and EcoEléctrica thermal plants are relatively constant over the forecast horizon as these units are base-loaded units with the lowest production costs and new unit additions and system improvements do not materially alter the dispatch profile of these facilities.

8.13.2 Environmental Compliance Summary

The portfolio results indicate compliance with the Clean Power Plan requirements, but not the GHG New Source Standard, for the same reasons indicated earlier in connection with Aguirre CC 1&2.

As shown in Figure 8-33, the portfolio meets the target emission rate in 2017 once AOGP becomes operational. The emission rate declines over time as the portfolio mix changes from oil fired generation capacity to new, more efficient natural gas fired generation capacity and greater renewable capacity. Total CO_2 emissions are expected to decline by 34 percent from 1,424 lb/MWh in 2016 to 938 lb/MWh in 2035.

In terms of RPS goals, the portfolio meets a reduced RPS goal of 10 percent renewable generation of energy sales by 2020, 12 percent by 2025, and 15 percent by 2035. Renewable penetration levels are expected to reach 21.87 percent in 2035, while the RPS is expected at 15 percent in 2035. Renewable energy comes in form of utility scale solar resources and distributed solar. However, the contractual capacity that PREPA is envisioning is not sufficient to meet the full RPS requirements, in part because of the low capacity factors associated with the solar resources.

8.13.3 Operational Performance Summary

The day-time renewable curtailments in the near and long term are within the two percent limit, but range 4 to 12 percent during 2019 - 2031 as both utility scale and distributed solar penetration increases. The portfolio performs well in terms of reliability with zero loss of load hours in most years except 2020 and 2021. P3F4 has the highest observed LOLH and this was confirmed occur due to multiple machine outages[57]. With the four GTs of the repowered Aguirre CC and Cambalache 1, there would be only one LOLH. The operating reserves are healthy for all years with the portfolio maintaining adequate spinning reserves to respond to generation and transmission contingencies.

[57] All 15 LOLH are due to the same event in October 6 and 7 2019 with multiple units out of service. Aguirre ST 1&2, Aguirre CC 1&2, San Juan CC 5 &6, 9 x 21 MW GTs, Palo Seco 3&4 and San Juan 9 are out. This is an extreme event even considering that some of the GTs may have been kept in reserve.

Section

9

Sensitivities Assessment

As per PREPA's request, Siemens team evaluated the following three sensitivities: "Full RPS Compliance", "Renewables Freeze at Current Contracts", and "No renewal of AES Contract".

9.1 Sensitivity 1: Full RPS Compliance

Sensitivity of a full RPS compliance is evaluated based on the recommended Portfolio 3, by holding all other variables and portfolio compositions constant, while adding more renewable generation to meet a full RPS compliance. As per the guidelines established in Act 82-2010, a full RPS compliance requires 12 percent renewable generation of energy sales in 2015, 15 percent renewable generation of energy sales in 2020, and 20 percent renewable generation of energy sales by 2035. The impacts of the full RPS compliance are evaluated by adding more renewable generation resources to the Portfolio 3 under all Futures to achieve 20 percent penetration in 2035.

Act 82-2010 establishes the requirements for the RPS. Section 2.12 (d) establishes reasons for which compliance is not possible, including insufficiency of renewable energy (v) and excessive cost (vi). It is important to refer to PREPA Renewable Generation Integration Study, (February 14, 2014), where PREPA's current generation configuration can only safely integrate a limited amount of renewables, until new and flexible generation is added.

Considering the above, the reduced compliance targets were selected due to the fact that: a) it is economically infeasible to meet the targets until the generating fleet is upgraded and curtailment impacts mitigated, and b) the current status of contracts that make it impossible to have 12 percent of the energy supplied from renewable resources by 2015 and very unlikely that 15 percent of the energy will be supplied from these resources by 2020. The reduced targets of 10 percent by 2020, 12 percent by 2025 and 15 percent by 2035 were considered a more realistic path.

A full RPS compliance will add significant costs to the PREPA system; this is shown in the increases of the annual system costs in 2035, ranging from $72 million (in Future 1) to $96 million (in Future 3).

Table 9-1 shows Sensitivity 1 system costs in 2035. The greatest cost increase was to be expected in Future 3 as it is efficient generation burning natural gas that is being displaced by the renewable. Future 4 is expected to have higher cost due to the fact that the amount of distributed generation is doubled in this Future.

Table 9-1: Sensitivity 1 System Costs in 2035

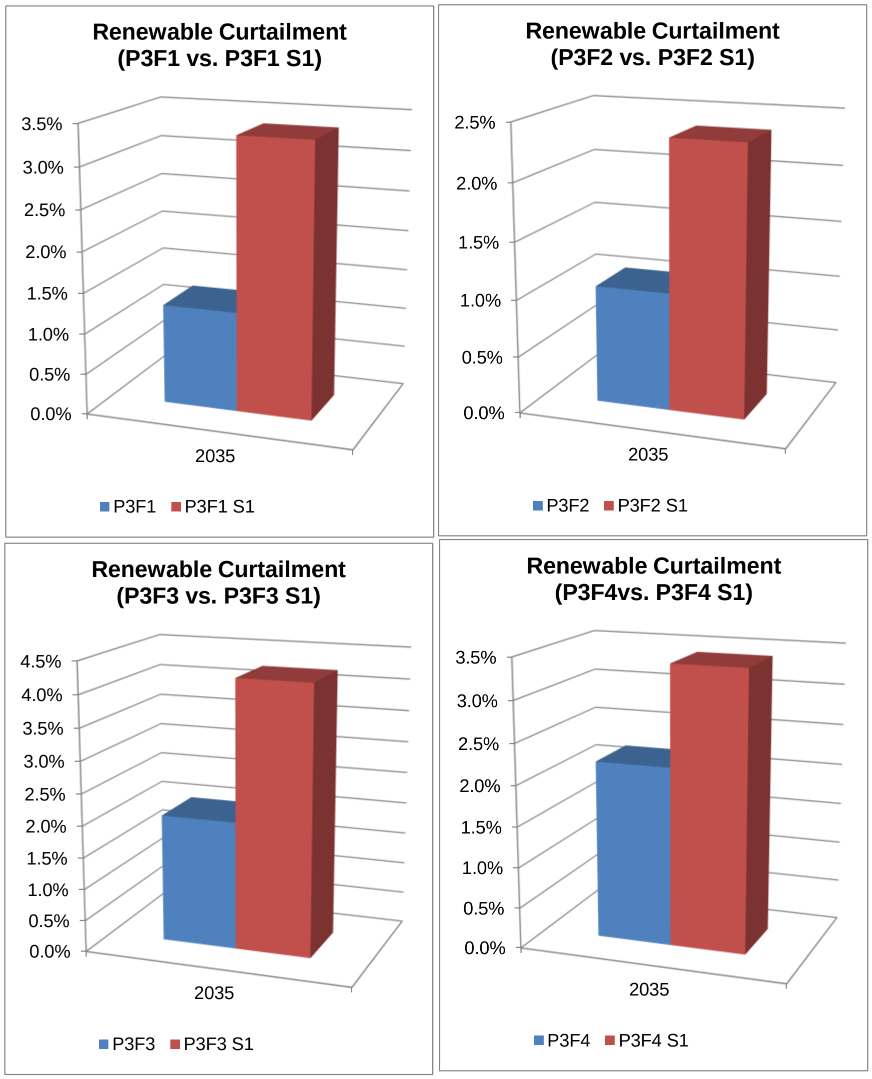
System Costs		P3F1 CY	P3F2	P3F3	P3F4
System Costs in 2035	*$ million*	2,306	2,689	2,385	2,343
System Costs		**P3F1-S1**	**P3F2-S1**	**P3F3-S1**	**P3F4-S1**
System Costs in 2035	*$ million*	2,378	2,767	2,481	2,428
Sensitivity S1 Incremental System Costs		**P3F1-S1**	**P3F2-S1**	**P3F3-S1**	**P3F4-S1**
Sensitivity S1 Incremental System Costs	*$ million*	72	78	96	85

Note: P3F1 CY and P3F1-S1 are based on calendar year 2035 results; all others presented in the table are based on fiscal year 2035 results.

Source: Siemens PTI, Pace Global

Curtailment also increases under Sensitivity 1 with increased renewables to be integrated into the PREPA system. Figure 9-1 shows the renewable curtailment for Sensitivity 1.

Figure 9-1: Sensitivity 1 Curtailment



Source: Siemens PTI, Pace Global

9.2 Sensitivity 2: Renewables Freeze at Current Contracts

This sensitivity case is the reverse of the case above and it evaluates the tradeoff of adding new renewable generations versus keeping the renewable generation at current levels. Siemens run sensitivity of the recommended Portfolio 3 under all four Futures to illustrate the cost and benefit implication of no additional new renewable generations.

As shown in Table 9-2, Sensitivity 2 incurs lower overall system costs because of lower levels of renewable generation. Average annual system costs savings range from $94 million (in Future 2) to $156 million (in Future 4). In addition, renewable curtailment drops significantly as shown in Figure 9-2.

As before the greater savings were expected in Future 3 due to the availability of gas and in Future 4 due to the doubling of distributed generation, which affected the curtailment. The reduced savings in Future 2 can be explained by the fact that in this future there is only gas at Costa Sur and EcoEléctrica, thus the energy produced by the renewable is replaced by relatively expensive LFO fired generation.

Table 9-2: Sensitivity 2 System Costs

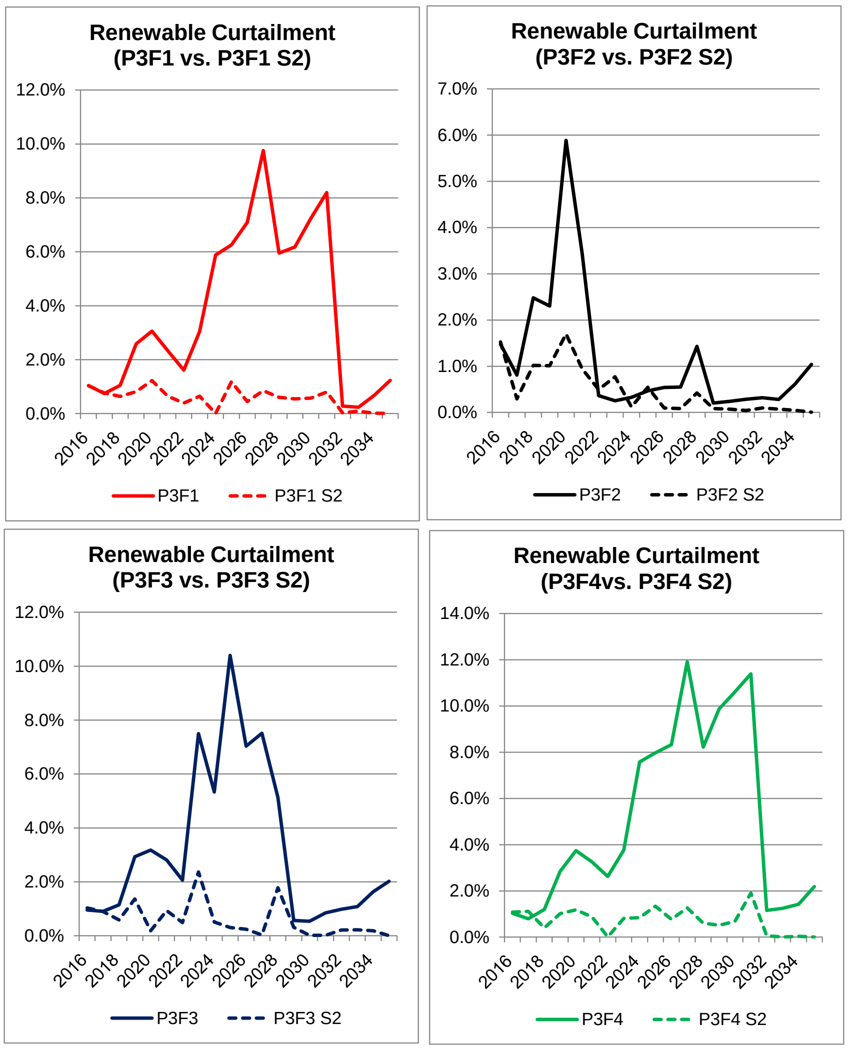
System Costs	Unit	P3F1	P3F2	P3F3	P3F4
Total Present Value of System Costs	*$ million*	26,842	29,301	26,660	26,648
Average Annual System Costs	*$ million*	2,415	2,663	2,394	2,397

System Costs	Unit	P3F1-S2	P3F2-S2	P3F3-S2	P3F4-S2
Total Present Value of System Costs	*$ million*	25,475	28,419	25,280	25,233
Average Annual System Costs	*$ million*	2,266	2,569	2,243	2,241

Sensitivity S2 Savings	Unit	P3F1-S2	P3F2-S2	P3F3-S2	P3F4-S2
Total Present Value of System Costs	*$ million*	1,367	882	1,381	1,415
Average Annual System Costs	*$ million*	149	94	151	156

Source: Siemens PTI, Pace Global

Figure 9-2: Sensitivity 2 Curtailment



Source: Siemens PTI, Pace Global

9.3 Sensitivity 3: No Renewal of AES Contract

This sensitivity case evaluates impacts of not extending AES-Puerto Rico (AES-PR) contract after its termination as expected in 2027. Specifically, Siemens assumed that in Portfolio 3 under all Futures, the AES-PR plant will not be in operation beyond its 2027 contract termination date. Because AES plant is currently PREPA's least expensive resource, its retirement will impact the overall costs of the Supply Portfolio.

As shown in Table 9-3, Sensitivity 3 incurs higher overall system costs in Future 1, 2 and 4, because of the displacement of the least cost resources with increased generation from the new H Class and F Class combined cycle units in Portfolio 3, some of which are burning LFO in the North of the island. The increase in system costs in Sensitivity 3 is more profound under Future 2, because the coal-fired generation is replaced with LFO-fired generation both in the North and South of the island. This resulted in a present value of the system costs for P2F2-S3 that is $756 million higher than P3F2.

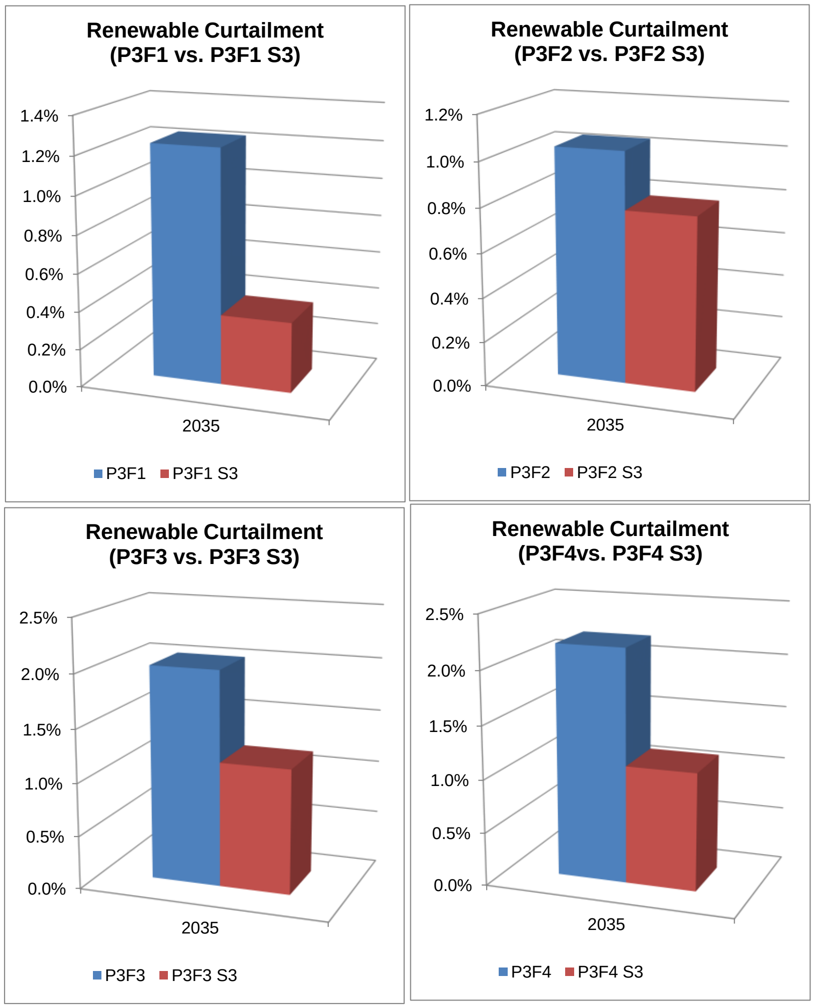
Curtailment and LOLH impacts are minimal in Sensitivity 3 as shown in Figure 9-3.

Table 9-3: Sensitivity 3 System Costs

System Costs	Unit	P2F1	P2F3	P2F4	P3F1	P3F2	P3F3	P3F4
Total Present Value of System Costs	*$ million*	26,930	26,871	26,757	26,842	29,301	26,660	26,648
Average Annual System Costs	*$ million*	2,428	2,421	2,411	2,415	2,663	2,394	2,397
System Costs	**Unit**	**P2F1-S3**	**P2F3-S3**	**P2F4-S3**	**P3F1-S3**	**P3F2-S3**	**P3F3-S3**	**P3F4-S3**
Total Present Value of System Costs	*$ million*	27,015	26,858	26,857	26,967	30,057	26,638	26,751
Average Annual System Costs	*$ million*	2,440	2,418	2,426	2,433	2,774	2,390	2,411
Sensitivity S3 Incremental System Costs	**Unit**	**P2F1-S3**	**P2F3-S3**	**P2F4-S3**	**P3F1-S3**	**P3F2-S3**	**P3F3-S3**	**P3F4-S3**
Total Present Value of System Costs	*$ million*	85	-13	100	126	756	-22	104
Average Annual System Costs	*$ million*	12	-3	14	18	111	-4	15

Source: Siemens PTI, Pace Global

Figure 9-3: Sensitivity 3 Curtailment



Source: Siemens PTI, Pace Global

Appendix

A

Glossary of Terms

Aguirre Offshore GasPort (AOGP): A floating offshore liquefied natural gas regasification facility off the southern coast of Puerto Rico. It will consist of three main components: an offshore berthing platform; an offshore marine LNG receiving facility consisting of an FSRU moored at the offshore berthing platform; and a subsea pipeline connecting the platform to the Aguirre Power Complex, which will run across the Jobos Bay.

Air Cooled Condensers (ACCs): Air Cooled Condenser is a direct dry cooling system where the steam is condensed inside air-cooled finned tubes.

Amortized capital Costs: Capital investment spread over time, typically following a fixed repayment schedule, often associated with the repayment of debt issued to finance such capital investment.

Army Corps of Engineers (ACOE): ACOE is a U.S. federal agency under the Department of Defense and a major Army command made up of some 37,000 civilian and military personnel, making it one of the world's largest public engineering, design, and construction management agencies. Although generally associated with dams, canals and flood protection in the United States, USACE is involved in a wide range of public works throughout the world.

British Thermal Unit (Btu): A unit of energy measure that indicates the amount of heat required to raise the temperature of one pound of water by 1oF at a constant atmospheric pressure.

Calculated Carbon Aromaticity Index (CCAI): CCAI is an index of the ignition quality of residual fuel oil. The running of all internal combustion engines is dependent on the ignition quality of the fuel.

Combined Cycle (CC): A form of power generation that captures exhaust heat often from a CT (or multiple CTs) to create additional electric power beyond that created by the simple CT and enhance the overall efficiency of the unit by producing more output for the same level of input.

Combustion Turbine (CT): A form of power generation that forces air into a chamber heated through the combustion of a type of fuel (often diesel or natural gas) which causes the heated air to expand and power the circulation of a turbine that spins an electric generator to produce electricity.

Capital Cost: The cost of various sources of funds used in a financing an entity’s operations.

Curtailment or Renewable Generation Curtailment: Curtailment happens when due to technical requirements of the conventional generating fleet a portion of the renewable generation cannot be accepted in the system and the renewable plant must back down its production although sun irradiation or wind is available. Curtailment also can have a financial impact to PREPA as per the existing contractual conditions if energy production capability is available given the meteorological conditions and PREPA cannot take it, then it has to be paid at the contractual prices and on an estimate of the energy that could have been produced.

Debt service: The amount of capital required to repay principal and/or interest on issued debt over a given period of time. Such repayment typically follows a predetermined schedule.

Discount rate: The percentage at which future cash flows are discounted based on the risk and uncertainty of the receipt of such cash flows over time. The greater the uncertainty of future cash flows, the more such cash flows will be discounted (assigned a higher discount rate) in determining the value of that stream of cash flows.

Distributed generation (DG): Electrical generation that is located on the distribution system (rather than the transmission system), often located at a customer's site on either the customer's or the utility's side of the electric meter.

Duct fire: Duct firing is firing of supplemental fuel in the gas turbine exhaust gas to raise its temperature entering the Heat Recovery Steam Generator, resulting in higher steam and power production.

Energy efficiency (EE): Any number of technologies employed to reduce energy consumption. Examples include more efficient lighting, refrigeration, heating, etc.

Engineering, Procurement and Construction (EPC): EPC is a prominent form of contracting agreement in the construction industry. The engineering and construction contractor will carry out the detailed engineering design of the project, procure all the equipment and materials necessary, and then construct to deliver a functioning facility or asset to their clients.

Federal Energy Regulatory Commission (FERC): FERC is the United States federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates. FERC also reviews and authorizes liquefied natural gas (LNG) terminals, interstate natural gas pipelines and non-federal hydropower projects.

Fixed operations and maintenance expenses (FOM): Expenses incurred as a result of operations and maintenance that do not vary with operations.

Floating Storage and Regasification Unit (FSRU): A Floating Storage Regasification Unit (FSRU) is the vital component required while transiting and transferring Liquefied Natural Gas (LNG) through the oceanic channels.

Forbearance agreement: An agreement achieved between a debtor and creditor(s), which delays the exercising of a legal right, often in conjunction with a debtor's delay or inability to repay issued debt.

Fossil fuel: A fuel source that is derived from the decomposition of plant and animal matter under the ground. Typically, coal, oil, and natural gas fall under the definition of fossil fuels.

Future: A Future is defined as a set of internally consistent assumptions that describe the future external environment in which PREPA might be expected to operate its Supply Portfolios.

Gas combustion turbine (GT): A form of power generation that forces air into a chamber heated through the combustion of a type of fuel (often diesel or natural gas) which causes the heated air to expand and power the circulation of a turbine that spins an electric generator to produce electricity.

Heat rate: The efficiency at which a generator converts input fuel to electric output, typically measured in Btu/kWh.

Heat Recovery Steam Generator (HRSG): HRSG is an energy recovery heat exchanger that recovers heat from a hot gas stream. It produces steam that can be used in a process (cogeneration) or used to drive a steam turbine (combined cycle).

Heavy Fuel Oil (HFO, No. 6 fuel oil or Bunker C): is a high-viscosity residual oil requiring preheating to 220 – 260 °F (104 – 127 °C).

Higher Heating Value (HHV): The higher heating value (also known gross calorific value or gross energy) of a fuel is defined as the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C, which takes into account the latent heat of vaporization of water in the combustion products.

Horizontal Directional Drilling (HDD): HDD is a steerable trenchless method of installing underground pipes, conduits and cables in a shallow arc along a prescribed bore path by using a surface-launched drilling rig, with minimal impact on the surrounding area.

Hydroelectric generation: Electrical generation that converts the kinetic energy of moving water to electricity by turning a turbine.

Integrated Resource Plan (IRP): The process of projecting future energy demand, and analyzing current and future energy, transmission, and distribution resources to plan to meet such future demand at minimized cost to the system owner/operator and its stakeholder.

Interest during Construction (IDC): IDC is any interest that is paid during the construction phase of a building or other tangible property.

Kilowatt (kW): One thousand watts.

Kilowatt-hour (kWh): One thousand watts produced for one hour of time.

Liquefied natural gas (LNG): Natural gas that has been converted to liquid form for ease of transport and/or storage.

Liquefied propane gas (LPG): Propane that has been converted to liquid form for ease of transport and/or storage.

Load forecast: A forecast of expected future energy demand based on an analysis of underlying economic indicators and past correlation between energy consumption and such economic conditions.

Loss of Load Hours (LOLH): LOLH is a metrics that considers all hours during a year which there may be a risk of insufficient generation.

Lower Heating Value (LVH): The lower heating value (also known as net calorific value) of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25°C) and returning the temperature of the combustion products to 150°C, which assumes the latent heat of vaporization of water in the reaction products is not recovered.

Mercury and Air Toxics Standards (MATS): MATS is an environmental regulation proposed by the US Environmental Protection Agency (EPA) in 2011 to reduce the emissions of hazardous air pollutants, such as mercury and acid gases, from coal-and-oil fired power plants.

Maximum capacity: The highest amount of electricity an electric generator or group of generators may produce within the design specifications of the generator.

Megawatt (MW): One million watts or 1,000 kilowatts.

Megawatt-hour (MWh): One million watts (or 1,000 kilowatts) produced for one hour of time.

Minimum capacity: The lowest amount of electricity an electric generator or group of generators may produce within the design specifications of the generator.

Minimum Down time: The period of time a generator needs to remain shut down before it can be started again.

Minimum Up time: The period of time a generator needs to remain operating after start up before it can be shut down again.

MMBtu: One million Btus.

MMcf: Million cubic feet

MMscf/d: One million standard cubic feet per day.

National Environmental Policy Act (NEPA): NEPA is a United States environmental law that established a U.S. national policy promoting the enhancement of the environment. NEPA's most significant accomplishment was setting up procedural requirements for all federal government agencies to prepare environmental assessments (EAs) and environmental impact statements (EISs).

Net Present Value (NPV): A method of calculating the current value of a series of cash flows, which considers the time value of money, and discounts future cash flows based on a determined discount rate or cost of capital.

New Source Performance Standards (NSPS): NSPS are pollution control standards issued by the United States Environmental Protection Agency (EPA). The term is used in the Clean Air Act Extension of 1970 (CAA) to refer to air pollution emission standards, and in the Clean Water Act (CWA) referring to standards for discharges of industrial wastewater to surface waters.

Operating reserves: Operating reserve is a portion of generating capacity available to the operator of a power system that may be increased or decreased in order to match short-term fluctuations in energy demand on the system.

Power Purchase and Operating Agreement (PPOA): A contract by which energy is bought and sold at prices and over time periods specified by the contractual terms.

Purchased power: Power purchased from a third party used to meet retail or wholesale electric demand.

Ramp rates or ramping speed: The speed at which a generating unit may increase and/or decrease output, typically measured in MW per minute.

Reciprocating engine: A generating unit type that utilizes the movement of pistons to convert pressure into a rotating motion, which can be used to turn an electric generator and produce electricity.

Regulation: An ancillary service product that provides extremely short term (intra-minute) upward and/or downward generation flexibility to meet fluctuations in load.

Renewable generation: Electric generation produced by a source that is considered to be readily renewable, including power generated by the wind, the sun (through photovoltaic processes or solar thermal processes), water (hydroelectric generation), biomass, etc.

Renewable Portfolio Standard (RPS): An energy policy which specifies the proportion of the energy mix that must come from renewable resources for an electricity provider. Typically, an RPS will require a certain percentage of renewables be used (on a capacity or energy basis) by a certain year in the future. Such policies will typically specify interim percentage targets in addition to final goals for renewable generation.

Reserve margin: A measure of available capacity over and above the capacity needed to meet normal peak demand levels.
Return on equity: The percentage rate of net return derived from an equity investment, or the annual or total net cash in-flow divided by the equity investment.

Right-of-Way (ROW): The legal right, established by usage or grant, to pass along a specific route through grounds or property belonging to another.

Photovoltaics (PV): is the name of a method of converting solar energy into direct current electricity using semiconducting materials that exhibit the photovoltaic effect, a phenomenon commonly studied in physics, photochemistry and electrochemistry**.**

Spinning reserves: An ancillary services product that provides available capacity to a power system operator over short- to medium-term time intervals, typically within ten minutes.

Steam Turbine Generator (STG): Generation that produces power through the process of boiling water to produce steam, which turns an electrical generator.

Supply Portfolio: A Supply Portfolio is the set of generation resources that PREPA can deploy to meet customer demand, environmental compliance, and system reliability requirements.

Thermal generation: Power generation created through the creation of heat, as contrasted against many renewable generation technologies (biomass and biogas excepted), which do not rely on heat to produce electricity.

Transmission system: The series of towers and wires that transmit electricity from generation sources to the distribution system at higher voltages than the distribution system to minimize technical losses of transmitted electricity.

The United States Environmental Protection Agency (EPA): EPA is an agency of the U.S. federal government which was created for the purpose of protecting human health and the environment by writing and enforcing regulations based on laws passed by Congress.

Ultra-low sulfur diesel (ULSD): ULSD is a cleaner-burning diesel fuel that contains 97 percent less sulfur than low-sulfur diesel (LSD).

Variable operations and maintenance expenses (VOM): Operations and maintenance expenses that vary as a function of the amount of energy that is being produced.

Weighted Average Cost of Capital (WACC): A calculation of a firm's cost of capital in which each category of capital is proportionately weighted. All capital sources - common stock, preferred stock, bonds and any other long-term debt - are included in a WACC calculation.

Appendix

B

Model Assumptions

Appendix B-1: Aguirre CC and ST Units Parameters

Parameters	Unit	Aguirre CC		Aguirre ST	
		Unit 1	Unit 2	Unit 1	Unit 2
Fuel	Type	Diesel	Diesel	No. 6 fuel oil	No. 6 fuel oil
Maximum Capacity	MW	260	260	450	450
Minimum Capacity	MW	49	49	230	230
Fixed O&M Expense	2015 $/kW-year	21.60	21.60	30.57	30.57
Variable O&M Expense	2015 $/MWh	6.48	6.48	2.15	2.15
Heat Rate at Maximum Capacity	MMBtu/MWh	11.14	11.14	9.60	9.70
Heat Rate at Minimum Capacity	MMBtu/MWh	11.42	11.42	9.86	10.05
Forced Outage	%	20%	20%	4%	4%
Minimum Downtime	Hours	0	0	48	48
Minimum Runtime	Hours	2	2	720	720
Ramp Up Rate	MW/minute	5	5	5	5
Ramp Down Rate	MW/minute	5	5	5	5

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-2: Costa Sur ST Parameters

Parameters	Unit	Costa Sur ST	
		Unit 5	Unit 6
Fuel	Type	Natural gas No. 6 fuel oil	Natural gas No. 6 fuel oil
Maximum Capacity	MW	410	410
Minimum Capacity	MW	250	250
Fixed O&M Expense	2015 $/kW-year	34.31	34.31
Variable O&M Expense	2015 $/MWh	2.60	2.60
Heat Rate at Maximum Capacity	MMBtu/MWh	9.75	9.97
Heat Rate at Minimum Capacity	MMBtu/MWh	9.84	10.02
Forced Outage	%	2%	3%
Minimum Downtime	Hours	48	48
Minimum Runtime	Hours	720	720
Ramp Up Rate	MW/minute	5	5
Ramp Down Rate	MW/minute	5	5

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-3: Palo Seco ST Parameters

Parameters	Unit	Palo Seco ST	
		Unit 3	Unit 4
Fuel	Type	No. 6 fuel oil	No. 6 fuel oil
Maximum Capacity	MW	216	216
Minimum Capacity	MW	130	130
Fixed O&M Expense	2015 $/kW-year	44.34	44.34
Variable O&M Expense	2015 $/MWh	4.72	4.72
Heat Rate at Maximum Capacity	MMBtu/MWh	9.73	9.73
Heat Rate at Minimum Capacity	MMBtu/MWh	10.35	10.35
Forced Outage	%	9%	3%
Minimum Downtime	Hours	48	48
Minimum Runtime	Hours	720	720
Ramp Up Rate	MW/minute	3	3
Ramp Down Rate	MW/minute	3	3

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-4: San Juan CC and ST Parameters

Parameters	Unit	San Juan CC		San Juan ST	
		Unit 5	Unit 6	Unit 9	Unit 10
Fuel	Type	Diesel	Diesel	No. 6 fuel oil	No. 6 fuel oil
Maximum Capacity	MW	200	200	100	100
Minimum Capacity	MW	155	155	70	70
Fixed O&M Expense	2015 $/kW-year	26.15	26.15	46.78	46.78
Variable O&M Expense	2015 $/MWh	2.12	2.12	2.69	2.69
Heat Rate at Maximum Capacity	MMBtu/MWh	7.63	7.85	10.28	10.26
Heat Rate at Minimum Capacity	MMBtu/MWh	8.46	8.86	10.35	10.50
Forced Outage	%	21%	10%	10%	9%
Minimum Downtime	Hours	48	48	48	48
Minimum Runtime	Hours	120	120	720	720
Ramp Up Rate	MW/minute	3	3	3	3
Ramp Down Rate	MW/minute	3	3	3	3

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-5: EcoEléctrica CC Parameters

Parameters	Unit	EcoEléctrica CC Unit 1
Fuel	Type	Natural Gas
Maximum Capacity	MW	507
Minimum Capacity	MW	275
Fixed O&M Expense	2015 $/kW-year	181
Variable O&M Expense	2015 $/MWh	0.00
Heat Rate at Maximum Capacity	MMBtu/MWh	7.50
Heat Rate at Minimum Capacity	MMBtu/MWh	8.31
Forced Outage	%	2%
Minimum Downtime	Hours	8
Minimum Runtime	Hours	168
Ramp Up Rate	MW/minute	10
Ramp Down Rate	MW/minute	10

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-6: AES Coal Plant Parameters

Parameters	Unit	AES Coal Plant	
		Unit 1	Unit 2
Fuel	Type	Coal	Coal
Maximum Capacity	MW	227	227
Minimum Capacity	MW	166	166
Fixed O&M Expense	2015 $/kW-year	75.97	75.97
Variable O&M Expense	2015 $/MWh	6.91	6.91
Heat Rate at Maximum Capacity	MMBtu/MWh	9.79	9.79
Heat Rate at Minimum Capacity	MMBtu/MWh	9.93	9.93
Forced Outage	%	3%	3%
Minimum Downtime	Hours	48	48
Minimum Runtime	Hours	720	720
Ramp Up Rate	MW/minute	0	0
Ramp Down Rate	MW/minute	0	0

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-7: Cambalache CT Parameters

Parameters	Unit	Cambalache CT		
		Unit 1	Unit 2	Unit 3
Fuel	Type	Diesel	Diesel	Diesel
Maximum Capacity	MW	83	83	83
Minimum Capacity	MW	50	50	50
Fixed O&M Expense	2015 $/kW-year	23.32	23.32	23.32
Variable O&M Expense	2015 $/MWh	5.27	5.27	5.27
Heat Rate at Maximum Capacity	MMBtu/MWh	11.55	11.55	11.55
Heat Rate at Minimum Capacity	MMBtu/MWh	11.55	11.55	11.55
Forced Outage	%	10%	10%	10%
Minimum Downtime	Hours	7	7	7
Minimum Runtime	Hours	7	7	7
Ramp Up Rate	MW/minute	2	2	2
Ramp Down Rate	MW/minute	2	2	2

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-8: Mayagüez CT Parameters

Parameters	Unit	Mayaguüez 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	2015 $/kW-year	10.15	10.15	10.15	10.15
Variable O&M Expense	2015 $/MWh	6.11	6.11	6.11	6.11
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

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-9: GT Units Parameters

Parameters	Unit	GT Units
		Each Unit
Fuel	Type	Diesel
Maximum Capacity	MW	21
Minimum Capacity	MW	21
Fixed O&M Expense	2015 $/kW-year	25.33
Variable O&M Expense	2015 $/MWh	19.27
Heat Rate at Maximum Capacity	MMBtu/MWh	14.40
Heat Rate at Minimum Capacity	MMBtu/MWh	14.40
Forced Outage	%	15%
Minimum Downtime	Hours	0
Minimum Runtime	Hours	0
Ramp Up Rate	MW/minute	2
Ramp Down Rate	MW/minute	2

Note: Ongoing generation assets' capital costs for maintenance, component replacements and upgrades which are included in the variable generation operation costs.

Appendix B-10: DOD Area Cost Factors (ACF)

DOD Area Cost Factors - OCONUS Pax Newsletter, dated 3/20/2014 (US Average=1.00)			
Country	Location & Local Currency per US Dollar	Service	Official ACF
Norway	Norwegian Kroner - 5.95950		**2.32**
	Oslo	Navy	2.32
Oman	Omani Rial - 0.38390		**1.20**
	Ruwi	Army	1.20
Peru	Peruvian Neuvo Sol - 2.74930		**0.89**
	Lima	Navy	0.89
Philippines	Philippine Peso - 43.21100		**1.22**
	Cubi Point	Navy	1.22
Poland	Polish Zloty - 3.10220		**0.97**
	Warsaw	Army	0.97
Puerto Rico	US Dollar - 1.00000		**1.16**
	Ponce/Fort Allen	Army	1.17
	San Juan Metro/Fort Buchanan	Army	1.14
Qatar	Qatari Rial - 3.63850		**1.23**
	Doha	Navy	1.23
Romania	Romanian New Leu - 3.29710		**1.09**
	Bucharest	Army	1.09
Saudi Arabia	Sauid Riyal - 3.74960		**1.29**
	Riyadh	Navy	1.29
Singapore	Singapore Dollar - 1.29490		**1.11**
	Singapore	Navy	1.11
Spain	Euro - 0.74520		**1.43**
	Moron	Army	1.41
	Rota	Navy	1.45
Turkey	Turkish Lira - 1.74640		**1.02**
	Ankara	Air Force	1.00
	Incirlik	Air Force	1.04
United Arab Emirates	UAE Dirham - 3.67270		**1.16**
	Dubai	Navy	1.16
United Kingdom	British Pound - 0.63630		**1.26**
	Fairford/Croughton	Air Force	1.27
	Lakenheath	Air Force	1.27
	Menwith Hill	Air Force	1.25
	West Ruislip	Air Force	1.25

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Appendix

C

Model Results

Appendix C-1: P1F1 Model Results

Puerto Rico Electric Power Authority
Portfolio 1; Future 1
IRP Metrics Analysis

	Unit	Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
COST	**Unit**	**Total / Average**								
Present Value of System Costs	*$000*	*27,274,349*	2,312,618	2,269,958	1,983,139	1,896,872	1,874,720	1,297,309	945,051	706,149
System Costs	*$000*	*2,475,823*	2,390,656	2,507,594	2,341,094	2,392,931	2,527,289	2,437,213	2,474,212	2,576,379
ENVIRONMENTAL COMPLIANCE										
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*12.12%*	*13.53%*	*15.25%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*13.97%*	*15.91%*	*18.14%*
OPERATIONS										
Renewable Curtailment	*percent*		*0.7%*	*0.9%*	*1.1%*	*2.3%*	*3.3%*	*4.1%*	*3.4%*	*8.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		5,017	8,541	13,128	35,391	61,149	95,604	89,542	249,776
Renewable Curtailment Cost	$000		659	1,173	1,849	5,106	9,002	13,978	12,836	35,404
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*70%*	*63%*	*59%*	*71%*	*71%*
Reserve Margin (without GTs & Cambalache)	*percent*		*51%*	*51%*	*52%*	*51%*	*44%*	*40%*	*52%*	*52%*

System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	$000		1,379,153	1,446,975	1,117,129	1,097,168	1,156,513	972,286	895,175	934,826
Regasification fixed costs	$000		-	-	84,086	92,823	91,238	90,664	90,097	90,279
O&M	$000		175,389	165,884	179,546	177,913	152,220	148,608	158,946	158,015
Purchased power	$000		734,793	722,831	681,319	676,672	666,475	630,500	632,447	646,138
Renewables	$000		90,654	132,039	174,259	225,201	273,334	341,566	382,399	431,973
Amortized capital costs	$000		10,667	39,864	104,755	123,155	187,509	253,590	315,148	315,148
Total System Costs	**$000**		**2,390,656**	**2,507,594**	**2,341,094**	**2,392,931**	**2,527,289**	**2,437,213**	**2,474,212**	**2,576,379**
Present Value of Total System Costs	**$000**		**2,312,618**	**2,269,958**	**1,983,139**	**1,896,872**	**1,874,720**	**1,297,309**	**945,051**	**706,149**

Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	46%	46%	40%	36%	36%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	26%	25%
Renewables	*percent*		4%	5%	7%	9%	11%	14%	15%	17%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	10%	13%	12%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Gross Energy Generation and Power Purchase Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Thermal Generation	MWh		12,376,367	12,147,808	11,810,571	11,626,603	11,269,497	10,663,747	10,619,585	10,565,518
Existing	*MWh*		12,376,367	12,147,808	11,810,571	11,626,603	11,269,497	7,381,658	109,449	156,237
New	*MWh*		-	-	-	-	-	3,282,089	10,510,136	10,409,281
Purchased Power	MWh		7,302,334	7,256,482	7,299,664	7,206,736	7,016,961	7,029,508	6,789,795	6,672,280
Renewable	MWh		823,773	1,095,013	1,371,135	1,695,131	1,991,360	2,470,684	2,801,719	3,181,746
Existing	*MWh*		553,545	582,900	610,150	633,062	655,807	766,458	876,925	988,586
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,558,539	1,779,106	2,047,473
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	MWh		20,502,475	20,499,303	20,481,370	20,528,470	20,277,818	20,163,939	20,211,098	20,419,544
System Heat Rate (Total Generation)	MMBtu/MWh		8.990	8.842	8.807	8.674	8.532	7.995	7.646	7.532
System Heat Rate (Thermal Generation)	MMBtu/MWh		9.367	9.341	9.439	9.455	9.461	9.111	8.877	8.922

Fuel Consumption Summary	**Unit**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Coal	MMBtu	32,682,235	32,544,403	33,176,356	32,066,624	31,628,100	32,275,873	31,530,501	31,505,268
No. 6 fuel oil	MMBtu	75,040,514	70,774,663	32,576,837	29,224,622	33,393,524	3,601,330	3,133,021	3,176,792
No. 2 fuel oil	MMBtu	9,246,606	13,587,232	5,269,984	3,408,738	6,856,012	7,195,334	1,417,322	1,968,069
Natural Gas	MMBtu	67,352,837	64,349,751	109,363,594	113,362,528	101,130,462	118,128,360	118,462,653	117,152,602
Total	MMBtu	184,322,191	181,256,049	180,386,772	178,062,512	173,008,098	161,200,896	154,543,496	153,802,731

Appendix C-2: P1F3 Model Results

Puerto Rico Electric Power Authority

Portfolio 1; Future 3

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
COST	**Unit**	**Total / Average**								
Present Value of System Costs	*$000*	*26,760,510*	2,326,221	2,273,596	1,987,696	1,897,924	1,876,006	1,238,127	926,549	689,987
System Costs	*$000*	*2,418,492*	2,404,718	2,511,613	2,346,474	2,394,258	2,529,022	2,326,030	2,425,772	2,517,411
Capital Costs (FY 2016 - 2025)	*$ million*	4,387	134	240	615	239	363	426	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	179								
Capital Costs (FY 2016 - 2035)	*$ million*	4,566								
ENVIRONMENTAL COMPLIANCE										
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*12.12%*	*13.53%*	*15.25%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*13.97%*	*15.91%*	*18.14%*
OPERATIONS										
Renewable Curtailment	*percent*		*1.1%*	*0.8%*	*0.9%*	*2.3%*	*3.6%*	*5.9%*	*9.1%*	*14.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		7,661	7,524	11,595	35,369	66,865	136,479	242,946	431,674
Renewable Curtailment Cost	$000		1,006	1,033	1,633	5,103	9,843	19,954	34,826	61,187
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*70%*	*63%*	*33%*	*71%*	*71%*
Reserve Margin (without GTs & Cambalache)	*percent*		*51%*	*51%*	*52%*	*51%*	*44%*	*14%*	*53%*	*52%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	$000		1,387,421	1,450,189	1,120,672	1,097,659	1,159,414	857,815	885,145	911,076
Regasification fixed costs	$000		-	-	84,056	92,847	91,021	84,410	86,853	86,957
O&M	$000		174,654	165,681	179,986	178,146	152,459	118,316	137,498	137,480
Purchased power	$000		741,322	723,840	682,746	677,251	665,285	623,649	619,019	635,067
Renewables	$000		90,654	132,039	174,259	225,201	273,334	341,566	382,399	431,973
Amortized capital costs	$000		10,667	39,864	104,755	123,155	187,509	300,274	314,858	314,858
Total System Costs	**$000**		**2,404,718**	**2,511,613**	**2,346,474**	**2,394,258**	**2,529,022**	**2,326,030**	**2,425,772**	**2,517,411**
Present Value of Total System Costs	**$000**		**2,326,221**	**2,273,596**	**1,987,696**	**1,897,924**	**1,876,006**	**1,238,127**	**926,549**	**689,987**
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	46%	46%	37%	36%	36%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	3%
O&M	*percent*		7%	7%	8%	7%	6%	5%	6%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	27%	26%	25%
Renewables	*percent*		4%	5%	7%	9%	11%	15%	16%	17%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	13%	13%	13%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Gross Energy Generation and Power Purchase Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Thermal Generation	MWh		12,362,182	12,156,704	11,766,709	11,632,476	11,296,374	10,838,908	11,054,655	10,978,401
Existing	*MWh*		12,362,182	12,156,704	11,766,709	11,632,476	11,296,374	4,335,152	2,482,446	2,329,489
New	*MWh*		-	-	-	-	-	6,503,756	8,572,209	8,648,911
Purchased Power	MWh		7,320,188	7,246,569	7,342,526	7,204,276	6,996,283	6,897,642	6,517,832	6,452,951
Renewable	MWh		823,773	1,095,013	1,371,135	1,695,131	1,991,360	2,470,684	2,801,719	3,181,746
Existing	*MWh*		553,545	582,900	610,150	633,062	655,807	766,458	876,925	988,586
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,558,539	1,779,106	2,047,473
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	MWh		20,506,143	20,498,286	20,480,370	20,531,882	20,284,017	20,207,235	20,374,206	20,613,098
System Heat Rate (Total Generation)	MMBtu/MWh		8.970	8.826	8.810	8.681	8.541	7.776	7.567	7.438
System Heat Rate (Thermal Generation)	MMBtu/MWh		9.345	9.324	9.442	9.462	9.471	8.860	8.773	8.795
Fuel Consumption Summary	**Unit**		**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Coal	MMBtu		32,833,706	32,180,484	33,579,202	32,124,312	31,299,063	31,500,575	30,411,660	30,310,267
Bunker	MMBtu		73,247,371	68,795,756	30,272,352	30,342,924	34,129,945	1,937,049	2,321,834	2,347,388
Light D.	MMBtu		11,019,179	14,923,974	6,845,743	2,796,350	6,442,043	1,091,517	99,392	306,605
Natural Gas	MMBtu		66,839,097	65,014,831	109,724,632	112,964,733	101,373,342	122,612,029	121,337,019	120,347,301
Total	MMBtu		183,939,353	180,915,045	180,421,929	178,228,318	173,244,394	157,141,169	154,169,905	153,311,560

Appendix C-3: P2F1 Model Results

Puerto Rico Electric Power Authority

Portfolio 2; Future 1

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,929,578*	2,321,260	2,275,588	1,996,412	1,894,910	1,879,368	1,785,732	1,615,353	1,430,696	1,346,440	1,262,673	916,732	653,608
System Costs	*$000*	*2,427,876*	2,399,590	2,513,814	2,356,763	2,390,456	2,533,555	2,572,534	2,486,787	2,353,666	2,367,068	2,372,144	2,400,071	2,384,684
Capital Costs (FY 2016 - 2025)	*$ million*	3,314	134	240	615	239	363	725	382	184	183	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	2,223												
Capital Costs (FY 2016 - 2035)	*$ million*	5,536												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.69%*	*6.20%*	*8.01%*	*9.71%*	*10.47%*	*10.75%*	*11.21%*	*11.82%*	*12.51%*	*13.96%*	*15.73%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*3.96%*	*5.55%*	*7.19%*	*9.09%*	*10.89%*	*11.76%*	*12.15%*	*12.73%*	*13.45%*	*14.26%*	*16.21%*	*18.46%*
OPERATIONS														
Renewable Curtailment	*percent*		*0.9%*	*0.5%*	*1.2%*	*1.8%*	*3.7%*	*2.7%*	*1.7%*	*2.5%*	*5.8%*	*5.3%*	*2.6%*	*0.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		6,210	4,418	14,901	27,845	67,159	53,496	34,604	53,231	127,513	120,674	66,932	6,472
Renewable Curtailment Cost	$000		829	616	2,127	4,064	9,993	7,991	5,138	7,877	18,859	17,865	9,732	932
LOLH	*hours*		*6.00*	*0.00*	*0.00*	*0.00*	*0.00*	*3.00*	*7.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*70%*	*63%*	*62%*	*50%*	*60%*	*62%*	*63%*	*70%*	*66%*
Reserve Margin (without GTs & Cambalache)	*percent*		*51%*	*51%*	*52%*	*51%*	*44%*	*43%*	*31%*	*41%*	*43%*	*44%*	*51%*	*47%*

System Costs Summary	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Fuel	$000		1,387,784	1,453,108	1,132,991	1,091,896	1,165,404	1,165,023	1,077,493	950,220	952,665	914,720	791,714	631,977
Regasification fixed costs	$000		-	-	84,129	92,773	91,195	92,730	92,414	90,820	92,684	90,631	90,193	87,054
O&M	$000		175,455	165,870	180,569	177,847	152,540	142,046	144,235	149,218	147,710	146,863	145,540	132,579
Purchased power	$000		735,030	722,933	680,060	679,584	663,573	659,252	650,884	632,643	614,528	624,775	635,162	675,200
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,365	431,959
Amortized capital costs	$000		10,667	39,864	104,755	123,155	187,509	218,627	220,224	219,338	233,883	253,590	355,098	425,915
Total System Costs	**$000**		2,399,590	2,513,814	2,356,763	2,390,456	2,533,555	2,572,534	2,486,787	2,353,666	2,367,068	2,372,144	2,400,071	2,384,684
Present Value of Total System Costs	**$000**		2,321,260	2,275,588	1,996,412	1,894,910	1,879,368	1,785,732	1,615,353	1,430,696	1,346,440	1,262,673	916,732	653,608

Percentage of System Costs	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Fuel	*percent*		58%	58%	48%	46%	46%	45%	43%	40%	40%	39%	33%	27%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	6%	6%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	26%	27%	26%	26%	26%	28%
Renewables	*percent*		4%	5%	7%	9%	11%	11%	12%	13%	14%	14%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	8%	9%	9%	10%	11%	15%	18%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Gross Energy Generation and Power Purchase Summary	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Thermal Generation	MWh		12,395,703	12,158,205	11,867,793	11,574,705	11,369,217	10,934,581	10,674,651	10,648,115	10,653,250	10,164,027	9,880,897	9,100,338
Existing	*MWh*		12,395,703	12,158,205	11,867,793	11,574,705	11,369,217	10,610,455	8,451,438	7,179,846	7,537,469	7,002,304	3,123,547	24,437
New	*MWh*		-	-	-	-	-	324,126	2,223,213	3,468,269	3,115,780	3,161,722	6,757,350	9,075,900
Purchased Power	MWh		7,295,707	7,251,032	7,261,963	7,265,848	6,944,922	7,135,378	7,226,599	6,995,319	6,769,801	6,933,740	6,891,308	7,286,380
Renewable	MWh		812,531	1,081,377	1,355,292	1,677,411	1,971,728	2,108,778	2,165,471	2,239,219	2,335,975	2,441,857	2,763,914	3,134,802
Existing	*MWh*		542,303	569,263	594,306	615,342	636,174	657,035	677,618	697,897	718,080	737,630	839,120	941,675
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,306,055	1,342,164	1,395,634	1,472,207	1,558,539	1,779,106	2,047,439
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	**MWh**		20,503,941	20,490,613	20,485,049	20,517,963	20,285,868	20,178,737	20,066,720	19,882,653	19,759,026	19,539,624	19,536,119	19,521,520
System Heat Rate (Total Generation)	**MMBtu/MWh**		9.029	8.873	8.857	8.701	8.571	8.416	8.155	8.083	8.078	7.996	7.422	6.761
System Heat Rate (Thermal Generation)	**MMBtu/MWh**		9.401	9.368	9.484	9.476	9.494	9.398	9.142	9.109	9.161	9.138	8.645	8.055

Fuel Consumption Summary	Unit		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Coal	MMBtu		32,535,711	32,435,343	33,083,972	32,414,460	31,452,717	32,107,455	32,529,298	32,393,147	30,542,160	31,919,845	32,193,871	33,900,086
No. 6 fuel oil	MMBtu		76,421,733	71,472,023	32,678,457	28,547,371	34,431,336	22,922,468	6,140,487	4,122,551	4,264,950	3,918,833	2,967,908	-
No. 2 fuel oil	MMBtu		8,610,580	13,444,544	5,800,860	3,279,991	6,168,910	13,501,154	17,389,095	7,165,963	5,557,672	5,353,645	716,574	369,763
Natural Gas	MMBtu		67,556,028	64,469,479	109,863,833	114,287,202	101,821,709	101,289,435	107,592,869	117,035,291	119,244,078	115,055,283	109,119,482	97,718,811
Total	MMBtu		185,124,051	181,821,388	181,427,122	178,529,024	173,874,672	169,820,512	163,651,749	160,716,953	159,608,860	156,247,605	144,997,834	131,988,660

Appendix C-4: P2F2 Model Results

Puerto Rico Electric Power Authority

Portfolio 2; Future 2

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
COST	**Unit**	**Total / Average**								
Present Value of System Costs	*$000*	*30,016,034*	2,271,189	2,206,700	2,135,364	2,056,795	2,022,392	1,495,457	1,066,740	810,730
System Costs	*$000*	*2,766,635*	2,347,829	2,437,714	2,520,796	2,594,676	2,726,363	2,809,468	2,792,804	2,957,941
Capital Costs (FY 2016 - 2025)	*$ million*	4,039	134	176	167	239	558	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	894								
Capital Costs (FY 2016 - 2035)	*$ million*	4,933								
ENVIRONMENTAL COMPLIANCE										
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.69%*	*6.20%*	*8.01%*	*9.71%*	*12.10%*	*13.50%*	*15.20%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*3.96%*	*5.55%*	*7.19%*	*9.09%*	*10.89%*	*13.79%*	*15.68%*	*17.86%*
OPERATIONS										
Renewable Curtailment	*percent*		*0.5%*	*1.1%*	*2.0%*	*2.9%*	*5.7%*	*0.1%*	*0.1%*	*0.1%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		3,586	10,684	24,510	44,938	103,384	2,920	2,881	3,564
Renewable Curtailment Cost	$000		479	1,489	3,498	6,558	15,383	432	419	513
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*61%*	*63%*	*68%*	*65%*	*65%*
Reserve Margin (without GTs & Cambalache)	*percent*		*50%*	*50%*	*50%*	*41%*	*42%*	*48%*	*44%*	*44%*

System Costs Summary	Unit	Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
Fuel	$000		1,336,451	1,385,193	1,415,459	1,424,798	1,469,479	1,302,323	1,168,951	1,269,552
Regasification fixed costs	$000		-	-	9,963	21,850	17,003	19,860	18,508	17,249
O&M	$000		175,218	174,543	172,156	165,623	146,951	138,222	132,926	131,549
Purchased power	$000		734,839	721,588	709,635	699,482	681,695	692,031	705,898	723,476
Renewables	$000		90,654	132,039	174,259	225,201	273,334	341,566	382,365	431,959
Amortized capital costs	$000		10,667	24,351	39,323	57,723	137,902	315,466	384,156	384,156
Total System Costs	**$000**		2,347,829	2,437,714	2,520,796	2,594,676	2,726,363	2,809,468	2,792,804	2,957,941
Present Value of Total System Costs	**$000**		2,271,189	2,206,700	2,135,364	2,056,795	2,022,392	1,495,457	1,066,740	810,730

Percentage of System Costs	$000	Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
Fuel	*percent*		57%	57%	56%	55%	54%	46%	42%	43%
Regasification fixed costs	*percent*		0%	0%	0%	1%	1%	1%	1%	1%
O&M	*percent*		7%	7%	7%	6%	5%	5%	5%	4%
Purchased power	*percent*		31%	30%	28%	27%	25%	25%	25%	24%
Renewables	*percent*		4%	5%	7%	9%	10%	12%	14%	15%
Amortized capital costs	*percent*		0%	1%	2%	2%	5%	11%	14%	13%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Gross Energy Generation and Power Purchase Summary	Unit	Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
Thermal Generation	MWh		12,407,903	12,188,693	12,071,086	11,926,049	11,591,678	9,582,016	9,414,064	9,149,805
Existing	*MWh*		12,407,903	12,188,693	12,071,086	11,926,049	11,486,460	5,083,610	45,201	76,905
New	*MWh*		-	-	-	-	105,217	4,498,406	9,368,863	9,072,900
Purchased Power	MWh		7,282,207	7,229,501	7,070,783	6,937,381	6,762,629	7,393,175	7,292,039	7,233,635
Renewable	MWh		812,531	1,081,377	1,355,292	1,677,411	1,971,728	2,441,857	2,763,914	3,134,802
Existing	*MWh*		542,303	569,263	594,306	615,342	636,174	737,630	839,120	941,675
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,558,539	1,779,106	2,047,439
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	**MWh**		20,502,641	20,499,571	20,497,161	20,540,841	20,326,035	19,417,048	19,470,017	19,518,242
System Heat Rate (Total Generation)	**MMBtu/MWh**		9.051	8.948	8.822	8.671	8.545	7.633	6.885	6.755
System Heat Rate (Thermal Generation)	**MMBtu/MWh**		9.425	9.446	9.447	9.442	9.463	8.731	8.024	8.048

Fuel Consumption Summary	Unit		2016	2017	2018	2019	2020	2025	2030	2035
Coal	MMBtu		32,631,748	32,163,020	32,234,905	31,066,752	30,827,626	34,218,706	34,389,041	34,191,651
No. 6 fuel oil	MMBtu		71,137,381	65,820,541	67,405,833	60,896,582	67,884,258	4,879,163	-	-
No. 2 fuel oil	MMBtu		6,544,397	5,550,629	8,552,792	9,247,285	9,817,164	35,741,587	30,172,006	31,208,449
Natural Gas	MMBtu		75,265,274	79,888,186	72,639,834	76,897,060	65,151,668	73,376,932	69,493,951	66,453,348
Total	MMBtu		185,578,800	183,422,377	180,833,364	178,107,679	173,680,717	148,216,389	134,054,997	131,853,448

Appendix C-5: P2F3 Model Results

Puerto Rico Electric Power Authority

Portfolio 2; Future 3

IRP Metrics Analysis

COST	**Unit**	**Total / Average**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Present Value of System Costs	*$000*	*26,870,672*	2,318,387	2,274,849	1,975,075	1,928,520	1,870,390	1,300,555	904,913	666,056
System Costs	*$000*	*2,420,593*	2,396,620	2,512,998	2,331,575	2,432,855	2,521,452	2,443,312	2,369,127	2,430,098
Capital Costs (FY 2016 - 2025)	*$ million*	5,097	134	240	615	239	363	709	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	894								
Capital Costs (FY 2016 - 2035)	*$ million*	5,992								

ENVIRONMENTAL COMPLIANCE		**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*12.12%*	*13.53%*	*15.25%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*13.97%*	*15.91%*	*18.14%*

OPERATIONS			**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Renewable Curtailment	*percent*		*1.2%*	*0.6%*	*1.5%*	*1.9%*	*4.7%*	*4.6%*	*0.3%*	*0.4%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		8,465	5,276	18,754	29,047	86,388	106,284	7,382	13,320
Renewable Curtailment Cost	$000		1,111	725	2,642	4,191	12,717	15,540	1,058	1,888
LOLH	*hours*		*2.00*	*0.00*	*0.00*	*3.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*70%*	*65%*	*70%*	*67%*	*67%*
Reserve Margin (without GTs & Cambalache)	*percent*		*51%*	*51%*	*52%*	*51%*	*47%*	*51%*	*48%*	*48%*

System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	$000		1,386,168	1,452,850	1,108,089	1,133,523	1,155,718	771,843	643,977	640,464
Regasification fixed costs	$000		-	-	85,142	89,337	92,837	93,420	92,320	92,547
O&M	$000		175,559	165,776	179,551	179,855	151,866	159,636	130,117	128,887
Purchased power	$000		733,573	722,468	679,780	681,784	660,189	621,232	653,216	669,108
Renewables	$000		90,654	132,039	174,259	225,201	273,334	341,566	382,363	431,958
Amortized capital costs	$000		10,667	39,864	104,755	123,155	187,509	455,616	467,134	467,134
Total System Costs	**$000**		2,396,620	2,512,998	2,331,575	2,432,855	2,521,452	2,443,312	2,369,127	2,430,098
Present Value of Total System Costs	**$000**		2,318,387	2,274,849	1,975,075	1,928,520	1,870,390	1,300,555	904,913	666,056

Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	47%	46%	32%	27%	26%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	7%	5%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	25%	28%	28%
Renewables	*percent*		4%	5%	7%	9%	11%	14%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	19%	20%	19%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Gross Energy Generation and Power Purchase Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Thermal Generation	MWh		12,399,568	12,160,566	11,849,692	11,515,333	11,439,754	10,228,804	9,511,667	9,237,623
Existing	*MWh*		12,399,568	12,160,566	11,849,692	11,515,333	11,439,754	5,698,435	1,698,406	1,636,633
New	*MWh*		-	-	-	-	-	4,530,369	7,813,260	7,600,990
Purchased Power	MWh		7,285,375	7,236,256	7,267,184	7,313,714	6,878,576	6,828,018	7,161,100	7,108,627
Renewable	MWh		823,773	1,095,013	1,371,135	1,695,131	1,991,360	2,470,592	2,801,565	3,181,587
Existing	*MWh*		553,545	582,900	610,150	633,062	655,807	766,365	876,772	988,465
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,558,539	1,779,106	2,047,434
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	**MWh**		20,508,717	20,491,835	20,488,012	20,524,177	20,309,690	19,527,414	19,474,332	19,527,836
System Heat Rate (Total Generation)	**MMBtu/MWh**		9.043	8.845	8.845	8.686	8.565	7.622	6.911	6.767
System Heat Rate (Thermal Generation)	**MMBtu/MWh**		9.422	9.345	9.480	9.468	9.496	8.726	8.072	8.085

Fuel Consumption Summary	**Unit**		**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Coal	MMBtu		32,636,296	32,268,484	32,969,510	32,812,255	30,998,482	30,814,625	33,236,629	33,236,328
No. 6 fuel oil	MMBtu		77,991,489	69,638,672	32,422,584	31,901,561	33,317,717	809,673	-	-
No. 2 fuel oil	MMBtu		7,437,957	14,409,869	3,700,028	5,930,649	5,420,049	102,134	7,970	12,129
Natural Gas	MMBtu		67,403,431	64,942,458	112,130,184	107,625,041	104,212,851	117,114,985	101,343,279	98,905,082
Total	MMBtu		185,469,172	181,259,483	181,222,306	178,269,507	173,949,098	148,841,416	134,587,878	132,153,539

Appendix C-6: P2F4 Model Results

Puerto Rico Electric Power Authority

Portfolio 2; Future 4

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
COST	**Unit**	**Total / Average**								
Present Value of System Costs	*$000*	*26,757,051*	2,318,016	2,259,899	1,981,466	1,881,561	1,870,045	1,273,287	908,398	644,914
System Costs	*$000*	*2,411,160*	2,396,236	2,496,483	2,339,120	2,373,616	2,520,986	2,392,084	2,378,252	2,352,964
Capital Costs (FY 2016 - 2025)	*$ million*	3,314	134	240	615	239	363	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	2,223								
Capital Costs (FY 2016 - 2035)	*$ million*	5,536								
ENVIRONMENTAL COMPLIANCE										
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.73%*	*6.25%*	*8.09%*	*9.82%*	*12.64%*	*14.40%*	*16.38%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.07%*	*5.73%*	*7.46%*	*9.54%*	*11.52%*	*15.67%*	*18.72%*	*21.87%*
OPERATIONS										
Renewable Curtailment	*percent*		*0.8%*	*0.8%*	*1.3%*	*2.2%*	*4.3%*	*8.2%*	*4.4%*	*0.6%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		5,609	7,213	16,223	35,401	83,097	207,036	131,941	22,795
Renewable Curtailment Cost	$000		728	981	2,245	4,951	11,750	27,734	16,712	2,786
LOLH	*hours*		*6.00*	*0.00*	*0.00*	*0.00*	*6.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*71%*	*71%*	*71%*	*64%*	*62%*	*71%*	*67%*
Reserve Margin (without GTs & Cambalache)	*percent*		*51%*	*52%*	*52%*	*52%*	*45%*	*43%*	*52%*	*48%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	$000		1,383,637	1,437,656	1,116,108	1,078,637	1,157,585	938,868	774,682	614,405
Regasification fixed costs	$000		-	-	84,191	92,736	90,944	90,671	90,333	87,202
O&M	$000		175,509	165,393	179,522	176,908	152,009	147,223	143,855	131,140
Purchased power	$000		735,770	721,531	680,285	676,979	659,605	620,167	631,935	662,355
Renewables	$000		90,654	132,039	174,259	225,201	273,334	341,566	382,349	431,946
Amortized capital costs	$000		10,667	39,864	104,755	123,155	187,509	253,590	355,098	425,915
Total System Costs	**$000**		2,396,236	2,496,483	2,339,120	2,373,616	2,520,986	2,392,084	2,378,252	2,352,964
Present Value of Total System Costs	**$000**		2,318,016	2,259,899	1,981,466	1,881,561	1,870,045	1,273,287	908,398	644,914
Percentage of System Costs	**$000**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	45%	46%	39%	33%	26%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%
Purchased power	*percent*		31%	29%	29%	29%	26%	26%	27%	28%
Renewables	*percent*		4%	5%	7%	9%	11%	14%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	11%	15%	18%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Gross Energy Generation and Power Purchase Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Thermal Generation	MWh		12,363,098	12,031,320	11,696,864	11,450,796	11,254,715	10,205,434	9,567,344	8,781,701
Existing	*MWh*		12,363,098	12,031,320	11,696,864	11,450,796	11,254,715	7,128,839	3,198,480	39,622
New	*MWh*		-	-	-	-	-	3,076,595	6,368,864	8,742,079
Purchased Power	MWh		7,307,646	7,243,395	7,277,668	7,214,785	6,863,394	6,846,433	6,769,009	6,976,319
Renewable	MWh		831,789	1,104,722	1,393,201	1,743,898	2,067,161	2,683,284	3,151,141	3,666,714
Existing	*MWh*		561,561	592,609	632,216	681,829	731,608	979,057	1,226,347	1,473,599
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,558,539	1,779,106	2,047,427
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	**MWh**		20,502,534	20,379,437	20,367,733	20,409,478	20,185,270	19,735,151	19,487,495	19,424,734
System Heat Rate (Total Generation)	**MMBtu/MWh**		9.026	8.860	8.817	8.661	8.526	7.909	7.271	6.555
System Heat Rate (Thermal Generation)	**MMBtu/MWh**		9.408	9.368	9.465	9.470	9.499	9.154	8.674	8.080
Fuel Consumption Summary	**Unit**		**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Coal	MMBtu		32,647,739	32,512,477	33,035,484	32,249,587	31,190,070	31,468,515	31,563,319	33,143,898
No. 6 fuel oil	MMBtu		76,430,981	70,583,836	32,805,649	29,183,382	34,486,479	3,413,932	3,321,469	-
No. 2 fuel oil	MMBtu		8,339,331	13,224,714	5,499,209	2,716,024	6,176,283	7,097,554	725,620	621,546
Natural Gas	MMBtu		67,637,161	64,242,683	108,246,141	112,612,500	100,254,295	114,104,334	106,092,388	93,565,315
Total	MMBtu		185,055,212	180,563,710	179,586,483	176,761,492	172,107,126	156,084,335	141,702,795	127,330,759

Appendix C-7: P3F1 Model Results

Puerto Rico Electric Power Authority
Portfolio 3; Future 1
IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2020	2025	2030	2035
COST	**Unit**	**Total / Average**							
Present Value of System Costs	*$000*	*26,841,580*	2,324,415	2,284,681	1,986,538	1,873,112	1,267,861	934,842	650,403
System Costs	*$000*	*2,415,319*	2,402,851	2,523,859	2,345,107	2,525,121	2,381,891	2,447,485	2,372,991
Capital Costs (FY 2016 - 2025)	*$ million*	3,329	134	240	615	239	248	462	-
Capital Costs (FY 2026 - 2035)	*$ million*	1,923							
Capital Costs (FY 2016 - 2035)	*$ million*	5,252							
ENVIRONMENTAL COMPLIANCE									
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.69%*	*6.20%*	*9.71%*	*12.51%*	*13.96%*	*15.73%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*7.17%*	*10.20%*	*13.32%*	*20.47%*	*26.52%*	*29.80%*	*33.67%*
OPERATIONS									
Renewable Curtailment	*percent*		*1.0%*	*0.7%*	*1.1%*	*3.1%*	*6.3%*	*7.2%*	*1.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		6,944	6,958	12,707	55,819	143,635	189,700	36,901
Renewable Curtailment Cost	$000		927	970	1,813	8,306	21,264	27,583	5,312
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*2.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*63%*	*68%*	*64%*	*62%*
Reserve Margin (without GTs & Cambalache)	*percent*		*51%*	*51%*	*52%*	*44%*	*49%*	*45%*	*43%*

System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2020**	**2025**	**2030**	**2035**
Fuel	$000		1,390,916	1,464,670	1,119,658	1,164,497	922,022	849,919	672,967
Regasification fixed costs	$000		-	-	84,194	90,919	90,672	92,460	89,338
O&M	$000		174,853	166,298	179,279	152,337	148,665	134,810	116,077
Purchased power	$000		735,761	720,987	682,963	666,665	624,128	623,039	659,827
Renewables	$000		90,654	132,039	174,259	273,334	341,566	382,365	431,959
Amortized capital costs	$000		10,667	39,864	104,755	177,368	254,839	364,891	402,822
Total System Costs	**$000**		2,402,851	2,523,859	2,345,107	2,525,121	2,381,891	2,447,485	2,372,991
Present Value of Total System Costs	**$000**		2,324,415	2,284,681	1,986,538	1,873,112	1,267,861	934,842	650,403

Percentage of System Costs	**$000**	**Fiscal Year**	**2016**	**2017**	**2018**	**2020**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	46%	39%	35%	28%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	6%	6%	6%	5%
Purchased power	*percent*		31%	29%	29%	26%	26%	25%	28%
Renewables	*percent*		4%	5%	7%	11%	14%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	7%	11%	15%	17%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Gross Energy Generation and Power Purchase Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2020**	**2025**	**2030**	**2035**
Thermal Generation	MWh		12,375,975	12,203,660	11,791,308	11,280,004	10,199,071	10,299,938	9,509,247
Existing	*MWh*		12,375,975	12,203,660	11,791,308	11,280,004	6,817,100	3,766,851	133,319
New	*MWh*		-	-	-	-	3,381,970	6,533,088	9,375,927
Purchased Power	MWh		7,317,801	7,212,111	7,334,975	7,020,415	6,923,236	6,597,234	6,908,185
Renewable	MWh		812,531	1,081,377	1,355,292	1,971,728	2,441,857	2,763,914	3,134,802
Existing	*MWh*		542,303	569,263	594,306	636,174	737,630	839,120	941,675
New	*MWh*		124,540	366,425	615,297	1,189,866	1,558,539	1,779,106	2,047,439
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	**MWh**		20,506,307	20,497,147	20,481,575	20,272,147	19,564,163	19,661,086	19,552,233
System Heat Rate (Total Generation)	**MMBtu/MWh**		9.017	8.875	8.830	8.558	7.966	7.427	6.694
System Heat Rate (Thermal Generation)	**MMBtu/MWh**		9.389	9.370	9.456	9.481	9.102	8.642	7.972

Fuel Consumption Summary	**Unit**		**2016**	**2017**	**2018**	**2020**	**2025**	**2030**	**2035**
Coal	MMBtu		32,793,541	32,106,877	33,430,803	31,559,680	31,881,206	30,793,675	33,120,344
No. 6 fuel oil	MMBtu		74,342,605	71,130,277	30,734,607	34,473,526	3,539,453	3,789,652	-
No. 2 fuel oil	MMBtu		10,132,312	14,316,471	6,173,447	6,703,737	6,250,001	2,179,537	2,049,963
Natural Gas	MMBtu		67,631,666	64,368,221	110,519,600	100,761,008	114,178,112	109,254,579	95,714,461
Total	MMBtu		184,900,124	181,921,846	180,858,456	173,497,951	155,848,772	146,017,443	130,884,768

Appendix C-8: P3F2 Model Results

Puerto Rico Electric Power Authority

Portfolio 3; Future 2

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
COST	**Unit**	**Total / Average**								
Present Value of System Costs	*$000*	*29,301,323*	2,317,231	2,245,720	2,117,647	2,093,813	1,990,775	1,465,713	992,330	736,972
System Costs	*$000*	*2,663,238*	2,395,425	2,480,819	2,499,881	2,641,375	2,683,742	2,753,588	2,597,993	2,688,837
Capital Costs (FY 2016 - 2025)	*$ million*	3,715	134	176	167	239	433	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	959								
Capital Costs (FY 2016 - 2035)	*$ million*	4,674								
ENVIRONMENTAL COMPLIANCE										
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*12.12%*	*13.53%*	*15.25%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*13.97%*	*15.91%*	*18.14%*
OPERATIONS										
Renewable Curtailment	*percent*		*1.5%*	*0.8%*	*2.5%*	*2.3%*	*5.9%*	*0.5%*	*0.2%*	*1.0%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		10,045	7,694	30,390	35,686	108,641	10,905	6,416	31,544
Renewable Curtailment Cost	$000		1,319	1,057	4,281	5,148	15,993	1,594	920	4,471
LOLH	*hours*		*0.00*	*0.00*	*3.00*	*0.00*	*4.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*61%*	*63%*	*63%*	*61%*	*61%*
Reserve Margin (without GTs & Cambalache)	*percent*		*50%*	*50%*	*50%*	*41%*	*42%*	*42%*	*40%*	*40%*

System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	$000		1,381,750	1,424,302	1,437,205	1,508,000	1,462,561	1,299,239	1,030,358	1,057,045
Regasification fixed costs	$000		-	-	7,919	11,860	15,545	15,858	16,847	17,112
O&M	$000		175,187	174,458	171,396	166,443	146,874	155,258	154,504	153,290
Purchased power	$000		737,167	725,668	669,779	672,149	657,666	652,561	650,857	666,369
Renewables	$000		90,654	132,039	174,259	225,201	273,334	341,566	382,363	431,958
Amortized capital costs	$000		10,667	24,351	39,323	57,723	127,761	289,105	363,063	363,063
Total System Costs	**$000**		2,395,425	2,480,819	2,499,881	2,641,375	2,683,742	2,753,588	2,597,993	2,688,837
Present Value of Total System Costs	**$000**		2,317,231	2,245,720	2,117,647	2,093,813	1,990,775	1,465,713	992,330	736,972

Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	57%	57%	57%	54%	47%	40%	39%
Regasification fixed costs	*percent*		0%	0%	0%	0%	1%	1%	1%	1%
O&M	*percent*		7%	7%	7%	6%	5%	6%	6%	6%
Purchased power	*percent*		31%	29%	27%	25%	25%	24%	25%	25%
Renewables	*percent*		4%	5%	7%	9%	10%	12%	15%	16%
Amortized capital costs	*percent*		0%	1%	2%	2%	5%	10%	14%	14%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Gross Energy Generation and Power Purchase Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Thermal Generation	MWh		12,399,788	12,131,891	12,064,151	11,743,280	11,514,878	9,484,130	9,503,245	9,304,344
Existing	*MWh*		12,399,788	12,131,891	12,064,151	11,743,280	11,385,386	5,074,093	144,948	216,444
New	*MWh*		-	-	-	-	129,491	4,410,037	9,358,297	9,087,900
Purchased Power	MWh		7,287,866	7,267,067	7,068,378	7,091,115	6,828,999	7,472,388	7,169,218	7,060,557
Renewable	MWh		823,773	1,095,013	1,371,135	1,695,131	1,991,360	2,470,592	2,801,565	3,181,587
Existing	*MWh*		553,545	582,900	610,150	633,062	655,807	766,365	876,772	988,465
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,558,539	1,779,106	2,047,434
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	**MWh**		20,511,428	20,493,971	20,503,665	20,529,526	20,335,237	19,427,110	19,474,029	19,546,488
System Heat Rate (Total Generation)	**MMBtu/MWh**		9.056	8.915	8.796	8.605	8.530	7.521	6.671	6.549
System Heat Rate (Thermal Generation)	**MMBtu/MWh**		9.435	9.418	9.426	9.379	9.456	8.617	7.792	7.823

Fuel Consumption Summary	**Unit**		**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Coal	MMBtu		32,823,760	32,309,678	31,803,753	31,704,065	30,622,250	33,902,006	33,366,790	33,126,956
No. 6 fuel oil	MMBtu		79,571,918	78,620,959	77,030,970	74,067,268	73,157,734	14,637,596	-	-
No. 2 fuel oil	MMBtu		6,047,058	6,598,916	7,622,551	15,527,990	7,157,258	32,306,424	30,833,261	29,155,842
Natural Gas	MMBtu		67,316,784	65,166,800	63,883,584	55,350,910	62,515,377	65,266,855	65,708,415	65,736,178
Total	MMBtu		185,759,519	182,696,352	180,340,858	176,650,233	173,452,619	146,112,882	129,908,466	128,018,976

Appendix C-9: P3F3 Model Results

Puerto Rico Electric Power Authority
Portfolio 3; Future 3
IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
COST	**Unit**	**Total / Average**								
Present Value of System Costs	*$000*	*26,660,369*	2,331,452	2,282,170	1,991,533	1,896,798	1,874,323	1,249,544	885,830	653,647
System Costs	*$000*	*2,393,565*	2,410,125	2,521,085	2,351,004	2,392,837	2,526,753	2,347,480	2,319,168	2,384,824
Capital Costs (FY 2016 - 2025)	*$ million*	4,766	134	240	615	239	239	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	950								
Capital Costs (FY 2016 - 2035)	*$ million*	5,716								
ENVIRONMENTAL COMPLIANCE										
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*12.12%*	*13.53%*	*15.25%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*13.97%*	*15.91%*	*18.14%*
OPERATIONS										
Renewable Curtailment	*percent*		*1.0%*	*0.9%*	*1.1%*	*2.9%*	*3.2%*	*10.4%*	*0.5%*	*2.0%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		6,465	8,634	14,092	45,394	58,646	241,789	14,393	61,376
Renewable Curtailment Cost	$000		849	1,186	1,985	6,549	8,633	35,353	2,063	8,700
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*4.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*70%*	*63%*	*64%*	*63%*	*62%*
Reserve Margin (without GTs & Cambalache)	*percent*		*51%*	*51%*	*52%*	*51%*	*44%*	*45%*	*44%*	*43%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	$000		1,392,104	1,460,050	1,125,720	1,096,226	1,164,725	794,780	641,263	642,535
Regasification fixed costs	$000		-	-	84,167	92,849	90,853	99,680	95,467	95,883
O&M	$000		174,747	165,935	179,940	177,741	152,612	133,160	114,893	114,201
Purchased power	$000		741,954	723,198	682,163	677,666	667,862	606,756	640,413	655,480
Renewables	$000		90,654	132,039	174,259	225,201	273,334	341,566	382,363	431,958
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	371,537	444,768	444,768
Total System Costs	**$000**		2,410,125	2,521,085	2,351,004	2,392,837	2,526,753	2,347,480	2,319,168	2,384,824
Present Value of Total System Costs	**$000**		2,331,452	2,282,170	1,991,533	1,896,798	1,874,323	1,249,544	885,830	653,647
Percentage of System Costs	**$000**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	46%	46%	34%	28%	27%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	5%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	28%	27%
Renewables	*percent*		4%	5%	7%	9%	11%	15%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	16%	19%	19%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Gross Energy Generation and Power Purchase Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Thermal Generation	MWh		12,353,756	12,170,779	11,782,378	11,632,900	11,234,925	10,660,816	9,730,720	9,559,020
Existing	*MWh*		12,353,756	12,170,779	11,782,378	11,632,900	11,234,925	4,817,629	1,018,226	997,142
New	*MWh*		-	-	-	-	-	5,843,187	8,712,493	8,561,877
Purchased Power	MWh		7,327,855	7,230,522	7,330,661	7,212,622	7,053,522	6,544,401	6,949,604	6,835,815
Renewable	MWh		823,773	1,095,013	1,371,135	1,695,131	1,991,360	2,470,592	2,801,565	3,181,587
Existing	*MWh*		553,545	582,900	610,150	633,062	655,807	766,365	876,772	988,465
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,558,539	1,779,106	2,047,434
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	**MWh**		20,505,384	20,496,314	20,484,174	20,540,653	20,279,807	19,675,808	19,481,889	19,576,421
System Heat Rate (Total Generation)	**MMBtu/MWh**		9.002	8.855	8.835	8.700	8.555	7.499	6.809	6.652
System Heat Rate (Thermal Generation)	**MMBtu/MWh**		9.379	9.355	9.468	9.482	9.486	8.576	7.953	7.943
Fuel Consumption Summary	**Unit**		**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Coal	MMBtu		32,868,423	32,034,118	33,529,424	32,280,932	31,810,664	29,936,364	32,568,039	32,322,515
No. 6 fuel oil	MMBtu		73,877,596	69,214,950	30,787,334	30,496,028	34,492,476	2,798,283	-	-
No. 2 fuel oil	MMBtu		10,765,654	15,141,070	6,616,158	2,313,503	6,937,331	157,701	49,964	58,625
Natural Gas	MMBtu		67,075,146	65,099,823	110,038,184	113,608,512	100,247,687	114,653,097	100,035,992	97,837,159
Total	MMBtu		184,586,820	181,489,961	180,971,100	178,698,976	173,488,159	147,545,446	132,653,994	130,218,300

Appendix C-10: P3F4 Model Results

Puerto Rico Electric Power Authority

Portfolio 3; Future 4

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2025	2030	2035
COST	**Unit**	**Total / Average**								
Present Value of System Costs	*$000*	*26,647,720*	2,321,778	2,263,686	1,980,026	1,890,766	1,857,038	1,267,453	926,382	642,129
System Costs	*$000*	*2,396,559*	2,400,125	2,500,666	2,337,420	2,385,229	2,503,452	2,381,124	2,425,336	2,342,802
Capital Costs (FY 2016 - 2025)	*$ million*	3,329	134	240	615	239	239	248	462	-
Capital Costs (FY 2026 - 2035)	*$ million*	1,923								
Capital Costs (FY 2016 - 2035)	*$ million*	5,252								
ENVIRONMENTAL COMPLIANCE										
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.73%*	*6.25%*	*8.09%*	*9.82%*	*12.64%*	*14.40%*	*16.38%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.07%*	*5.73%*	*7.46%*	*9.54%*	*11.52%*	*15.67%*	*18.72%*	*21.87%*
OPERATIONS										
Renewable Curtailment	*percent*		*1.0%*	*0.8%*	*1.2%*	*2.8%*	*3.7%*	*8.0%*	*10.6%*	*2.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		7,099	7,613	14,898	45,423	71,975	202,404	318,842	77,090
Renewable Curtailment Cost	$000		921	1,035	2,062	6,353	10,178	27,114	40,386	9,421
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*15.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*71%*	*71%*	*71%*	*64%*	*68%*	*65%*	*63%*
Reserve Margin (without GTs & Cambalache)	*percent*		*51%*	*52%*	*52%*	*52%*	*45%*	*48%*	*45%*	*44%*

System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	$000		1,388,350	1,441,651	1,113,927	1,093,852	1,147,193	924,834	834,916	662,608
Regasification fixed costs	$000		-	-	84,181	92,635	90,787	90,650	92,479	89,696
O&M	$000		174,769	165,729	179,298	177,339	151,524	148,371	133,866	116,276
Purchased power	$000		735,685	721,382	681,001	673,047	663,245	620,864	616,835	639,454
Renewables	$000		90,654	132,039	174,259	225,201	273,334	341,566	382,349	431,946
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	254,839	364,891	402,822
Total System Costs	**$000**		2,400,125	2,500,666	2,337,420	2,385,229	2,503,452	2,381,124	2,425,336	2,342,802
Present Value of Total System Costs	**$000**		2,321,778	2,263,686	1,980,026	1,890,766	1,857,038	1,267,453	926,382	642,129

Percentage of System Costs	**$000**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	46%	46%	39%	34%	28%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	25%	27%
Renewables	*percent*		4%	5%	7%	9%	11%	14%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	11%	15%	17%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Gross Energy Generation and Power Purchase Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Thermal Generation	MWh		12,357,492	12,047,439	11,680,585	11,548,893	11,153,552	10,187,477	10,053,757	9,308,573
Existing	*MWh*		12,357,492	12,047,439	11,680,585	11,548,893	11,153,552	6,918,275	3,795,476	127,508
New	*MWh*		-	-	-	-	-	3,269,203	6,258,281	9,181,065
Purchased Power	MWh		7,316,954	7,227,912	7,292,199	7,129,454	6,949,179	6,860,041	6,471,305	6,504,274
Renewable	MWh		831,789	1,104,722	1,393,201	1,743,898	2,067,161	2,683,284	3,151,141	3,666,714
Existing	*MWh*		561,561	592,609	632,216	681,829	731,608	979,057	1,226,347	1,473,599
New	*MWh*		124,540	366,425	615,297	916,381	1,189,866	1,558,539	1,779,106	2,047,427
Hydro	*MWh*		145,688	145,688	145,688	145,688	145,688	145,688	145,688	145,688
Total	**MWh**		20,506,235	20,380,073	20,365,986	20,422,245	20,169,892	19,730,802	19,676,202	19,479,561
System Heat Rate (Total Generation)	**MMBtu/MWh**		9.008	8.865	8.815	8.674	8.510	7.882	7.277	6.502
System Heat Rate (Thermal Generation)	**MMBtu/MWh**		9.389	9.373	9.462	9.484	9.482	9.122	8.665	8.009

Fuel Consumption Summary	**Unit**		**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Coal	MMBtu		32,790,079	32,282,850	33,112,282	31,687,865	31,337,786	31,531,286	30,486,252	32,546,326
No. 6 fuel oil	MMBtu		74,255,609	70,708,917	30,434,939	31,529,988	34,115,546	3,620,628	3,868,744	-
No. 2 fuel oil	MMBtu		10,050,428	13,345,495	6,470,900	2,230,900	6,254,438	6,309,539	2,255,863	2,178,495
Natural Gas	MMBtu		67,619,344	64,330,956	109,508,139	111,691,711	99,945,212	114,048,877	106,576,847	91,927,792
Total	MMBtu		184,715,459	180,668,219	179,526,260	177,140,465	171,652,982	155,510,330	143,187,706	126,652,613

Appendix C-11: P3F1 S1 Model Results (Full RPS Compliance Sensitivity)

Puerto Rico Electric Power Authority
Portfolio 3; Future 1; Sensitivity 1
IRP Metrics Analysis

		Canlendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,711,899*	2,397,629	2,115,281	2,009,187	1,950,972	1,887,547	1,762,430	1,540,675	1,424,114	1,341,675	1,272,990	936,058	651,785
System Costs	*$000*	*2,404,648*	2,478,536	2,336,725	2,371,845	2,461,179	2,544,581	2,538,965	2,371,822	2,342,838	2,358,691	2,391,527	2,450,668	2,378,032
Capital Costs (FY 2016 - 2025)	*$ million*	3,329	134	240	615	239	239	865	382	184	183	248	462	-
Capital Costs (FY 2026 - 2035)	*$ million*	1,923												
Capital Costs (FY 2016 - 2035)	*$ million*	5,252												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*4.00%*	*5.41%*	*6.97%*	*9.07%*	*10.41%*	*10.61%*	*10.94%*	*11.51%*	*12.12%*	*12.85%*	*14.18%*	*21.41%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.79%*	*6.33%*	*8.01%*	*10.20%*	*11.65%*	*11.95%*	*12.40%*	*13.09%*	*13.81%*	*14.64%*	*16.48%*	*24.42%*
OPERATIONS														
Renewable Curtailment	*percent*		*0.6%*	*1.1%*	*1.4%*	*2.4%*	*4.2%*	*0.7%*	*2.2%*	*3.1%*	*6.2%*	*6.3%*	*7.9%*	*3.3%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		5,232	11,458	18,394	40,275	80,624	14,796	44,501	66,683	139,334	148,982	210,657	124,586
Renewable Curtailment Cost	$000		716	1,620	2,647	5,942	12,085	2,203	6,589	9,864	20,601	22,088	30,622	18,584
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*2.00*	*4.00*	*2.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
System Costs Summary	**Unit**	**Calendar Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,466,357	1,269,568	1,124,485	1,145,716	1,176,380	1,119,258	961,434	930,905	933,296	922,622	843,833	585,114
Regasification fixed costs	$000		-	-	84,195	92,007	91,478	92,840	92,730	90,779	91,844	91,272	95,357	88,589
O&M	$000		175,625	168,204	178,994	174,717	147,498	142,730	147,408	150,259	148,750	148,909	136,421	113,150
Purchased power	$000		714,083	706,467	683,175	671,288	659,637	666,109	644,044	631,873	617,380	622,460	621,470	631,834
Renewables	$000		111,804	152,622	196,240	254,295	292,219	298,151	304,732	318,435	332,289	351,424	388,697	556,524
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	221,474	220,587	235,133	254,839	364,891	402,822
Total System Costs	**$000**		2,478,536	2,336,725	2,371,845	2,461,179	2,544,581	2,538,965	2,371,822	2,342,838	2,358,691	2,391,527	2,450,668	2,378,032
Present Value of Total System Costs	**$000**		2,397,629	2,115,281	2,009,187	1,950,972	1,887,547	1,762,430	1,540,675	1,424,114	1,341,675	1,272,990	936,058	651,785
Percentage of System Costs	**Unit**	**Calendar Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		59%	54%	47%	47%	46%	44%	41%	40%	40%	39%	34%	25%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	6%	5%
Purchased power	*percent*		29%	30%	29%	27%	26%	26%	27%	27%	26%	26%	25%	27%
Renewables	*percent*		5%	7%	8%	10%	11%	12%	13%	14%	14%	15%	16%	23%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	9%	9%	9%	10%	11%	15%	17%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-12: P3F2 S1 Model Results (Full RPS Compliance Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 2; Sensitivity 1

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*29,322,809*	2,317,231	2,245,720	2,117,647	2,093,813	1,990,775	1,909,027	1,819,372	1,670,345	1,586,814	1,465,713	992,330	758,459
System Costs	*$000*	*2,667,157*	2,395,425	2,480,819	2,499,881	2,641,375	2,683,742	2,750,153	2,800,868	2,747,917	2,789,651	2,753,588	2,597,993	2,767,230
Capital Costs (FY 2016 - 2025)	*$ million*	3,715	134	176	167	239	433	1,287	663	184	183	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	959												
Capital Costs (FY 2016 - 2035)	*$ million*	4,674												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*10.48%*	*10.77%*	*11.10%*	*11.58%*	*12.12%*	*13.53%*	*19.42%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*11.89%*	*12.29%*	*12.74%*	*13.33%*	*13.97%*	*15.91%*	*22.17%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.5%*	*0.8%*	*2.5%*	*2.3%*	*5.9%*	*3.4%*	*0.4%*	*0.3%*	*0.3%*	*0.5%*	*0.2%*	*2.4%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		10,045	7,694	30,390	35,686	108,641	68,045	7,432	5,352	7,252	10,905	6,416	87,574
Renewable Curtailment Cost	$000		1,319	1,057	4,281	5,148	15,993	10,054	1,091	783	1,060	1,594	920	13,103
LOLH	*hours*		*0.00*	*0.00*	*3.00*	*0.00*	*4.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*68%*	*70%*	*69%*	*61%*	*60%*	*97%*	*90%*	*60%*	*61%*	*63%*	*61%*	*61%*
Reserve Margin (without GTs & Cambalache)	*percent*		*28%*	*29%*	*29%*	*25%*	*25%*	*39%*	*37%*	*25%*	*25%*	*26%*	*25%*	*25%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,381,750	1,424,302	1,437,205	1,508,000	1,462,561	1,421,181	1,360,466	1,354,920	1,378,722	1,299,239	1,030,358	1,025,007
Regasification fixed costs	$000		-	-	7,919	11,860	15,545	15,725	15,803	15,704	12,105	15,858	16,847	16,283
O&M	$000		175,187	174,458	171,396	166,443	146,874	159,648	163,908	157,447	158,004	155,258	154,504	151,768
Purchased power	$000		737,167	725,668	669,779	672,149	657,666	654,149	661,756	653,564	645,822	652,561	650,857	654,385
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,363	556,724
Amortized capital costs	$000		10,667	24,351	39,323	57,723	127,761	204,594	297,399	254,854	269,399	289,105	363,063	363,063
Total System Costs	**$000**		2,395,425	2,480,819	2,499,881	2,641,375	2,683,742	2,750,153	2,800,868	2,747,917	2,789,651	2,753,588	2,597,993	2,767,230
Present Value of Total System Costs	**$000**		2,317,231	2,245,720	2,117,647	2,093,813	1,990,775	1,909,027	1,819,372	1,670,345	1,586,814	1,465,713	992,330	758,459
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	57%	57%	57%	54%	52%	49%	49%	49%	47%	40%	37%
Regasification fixed costs	*percent*		0%	0%	0%	0%	1%	1%	1%	1%	0%	1%	1%	1%
O&M	*percent*		7%	7%	7%	6%	5%	6%	6%	6%	6%	6%	6%	5%
Purchased power	*percent*		31%	29%	27%	25%	25%	24%	24%	24%	23%	24%	25%	24%
Renewables	*percent*		4%	5%	7%	9%	10%	11%	11%	11%	12%	12%	15%	20%
Amortized capital costs	*percent*		0%	1%	2%	2%	5%	7%	11%	9%	10%	10%	14%	13%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-13: P3F3 S1 Model Results (Full RPS Compliance Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 3; Sensitivity 1

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,686,818*	2,331,452	2,282,170	1,991,533	1,896,798	1,874,323	1,785,184	1,595,430	1,430,127	1,360,560	1,249,544	885,830	680,086
System Costs	*$000*	*2,398,390*	2,410,125	2,521,085	2,351,004	2,392,837	2,526,753	2,571,745	2,456,116	2,352,729	2,391,892	2,347,480	2,319,168	2,481,290
Capital Costs (FY 2016 - 2025)	*$ million*	4,766	134	240	615	239	239	865	399	1,116	672	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	950												
Capital Costs (FY 2016 - 2035)	*$ million*	5,716												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*10.48%*	*10.77%*	*11.10%*	*11.58%*	*12.12%*	*13.53%*	*19.42%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*11.89%*	*12.29%*	*12.74%*	*13.33%*	*13.97%*	*15.91%*	*22.17%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.0%*	*0.9%*	*1.1%*	*2.9%*	*3.2%*	*2.8%*	*2.1%*	*7.5%*	*5.3%*	*10.4%*	*0.5%*	*4.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		6,465	8,634	14,092	45,394	58,646	55,789	42,148	158,861	118,159	241,789	14,393	156,866
Renewable Curtailment Cost	*$000*		849	1,186	1,985	6,549	8,633	8,243	6,187	23,230	17,264	35,353	2,063	23,470
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*4.00*	*3.00*	*6.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,392,104	1,460,050	1,125,720	1,096,226	1,164,725	1,165,836	1,043,801	875,449	800,249	794,780	641,263	628,216
Regasification fixed costs	$000		-	-	84,167	92,849	90,853	92,825	92,750	101,050	93,063	99,680	95,467	96,818
O&M	$000		174,747	165,935	179,940	177,741	152,612	141,909	144,830	149,985	154,297	133,160	114,893	114,554
Purchased power	$000		741,954	723,198	682,163	677,666	667,862	656,441	650,210	612,898	609,681	606,756	640,413	640,210
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,363	556,724
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	222,990	301,918	409,002	371,537	444,768	444,768
Total System Costs	**$000**		2,410,125	2,521,085	2,351,004	2,392,837	2,526,753	2,571,745	2,456,116	2,352,729	2,391,892	2,347,480	2,319,168	2,481,290
Present Value of Total System Costs	**$000**		2,331,452	2,282,170	1,991,533	1,896,798	1,874,323	1,785,184	1,595,430	1,430,127	1,360,560	1,249,544	885,830	680,086
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	46%	46%	45%	42%	37%	33%	34%	28%	25%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	5%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	26%	26%	25%	26%	28%	26%
Renewables	*percent*		4%	5%	7%	9%	11%	11%	12%	13%	14%	15%	16%	22%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	9%	9%	13%	17%	16%	19%	18%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-14: P3F4 S1 Model Results (Full RPS Compliance Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 4; Sensitivity 1

IRP Metrics Analysis

		Fiscal Year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,670,940*	2,321,778	2,263,686	1,980,026	1,890,766	1,857,038	1,761,577	1,583,768	1,414,429	1,325,421	1,267,453	926,382	665,348
System Costs	*$000*	*2,400,794*	2,400,125	2,500,666	2,337,420	2,385,229	2,503,452	2,537,736	2,438,163	2,326,904	2,330,116	2,381,124	2,425,336	2,427,518
Capital Costs (FY 2016 - 2025)	*$ million*	3,329	134	240	615	239	239	865	382	184	183	248	462	-
Capital Costs (FY 2026 - 2035)	*$ million*	1,923												
Capital Costs (FY 2016 - 2035)	*$ million*	5,252												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.73%*	*6.25%*	*8.09%*	*9.82%*	*10.61%*	*10.92%*	*11.41%*	*12.05%*	*12.64%*	*14.40%*	*20.86%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.07%*	*5.73%*	*7.46%*	*9.54%*	*11.52%*	*12.58%*	*13.15%*	*13.92%*	*14.84%*	*15.67%*	*18.72%*	*26.06%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.0%*	*0.8%*	*1.2%*	*2.8%*	*3.7%*	*3.3%*	*2.6%*	*3.8%*	*7.6%*	*8.0%*	*10.6%*	*3.4%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		7,108	7,620	14,890	45,418	71,992	68,054	57,054	85,776	181,988	202,407	318,851	143,050
Renewable Curtailment Cost	$000		922	1,036	2,060	6,353	10,180	9,561	7,874	11,676	24,540	27,114	40,387	18,928
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*15.00*	*4.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*

System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,388,350	1,441,651	1,113,927	1,093,852	1,147,193	1,133,311	1,031,787	926,616	917,508	924,834	834,916	644,492
Regasification fixed costs	$000		-	-	84,181	92,635	90,787	92,896	92,686	90,727	92,675	90,650	92,479	89,372
O&M	$000		174,769	165,729	179,298	177,339	151,524	141,041	144,369	150,250	148,407	148,371	133,866	116,185
Purchased power	$000		735,685	721,382	681,001	673,047	663,245	655,754	646,310	627,295	610,794	620,864	616,835	617,950
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,349	556,698
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	221,474	220,587	235,133	254,839	364,891	402,822
Total System Costs	**$000**		2,400,125	2,500,666	2,337,420	2,385,229	2,503,452	2,537,736	2,438,163	2,326,904	2,330,116	2,381,124	2,425,336	2,427,518
Present Value of Total System Costs	**$000**		2,321,778	2,263,686	1,980,026	1,890,766	1,857,038	1,761,577	1,583,768	1,414,429	1,325,421	1,267,453	926,382	665,348

Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	46%	46%	45%	42%	40%	39%	39%	34%	27%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	6%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	27%	27%	26%	26%	25%	25%
Renewables	*percent*		4%	5%	7%	9%	11%	12%	12%	13%	14%	14%	16%	23%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	9%	9%	9%	10%	11%	15%	17%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-15: P3F1 S2 Model Results (Renewables Freeze Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 1 Sensitivity 2

IRP Metrics Analysis

		Fiscal Year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*25,474,926*	2,317,302	2,264,843	1,946,012	1,840,417	1,795,966	1,723,971	1,526,455	1,346,039	1,252,564	1,182,609	852,843	584,828
System Costs	*$000*	*2,265,968*	2,395,498	2,501,944	2,297,267	2,321,712	2,421,121	2,483,561	2,349,931	2,214,394	2,202,033	2,221,730	2,232,804	2,133,739
Capital Costs (FY 2016 - 2025)	*$ million*	3,329	134	240	615	239	239	865	382	184	183	248	462	-
Capital Costs (FY 2026 - 2035)	*$ million*	1,923												
Capital Costs (FY 2016 - 2035)	*$ million*	5,252												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*2.49%*	*2.56%*	*2.62%*	*2.79%*	*2.98%*	*2.99%*	*3.01%*	*3.05%*	*3.08%*	*3.12%*	*3.13%*	*3.15%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*3.28%*	*3.52%*	*3.74%*	*4.03%*	*4.36%*	*4.51%*	*4.67%*	*4.85%*	*5.04%*	*5.22%*	*5.90%*	*6.57%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.0%*	*0.8%*	*0.6%*	*0.8%*	*1.2%*	*0.6%*	*0.4%*	*0.6%*	*0.0%*	*1.2%*	*0.6%*	*0.0%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		5,732	4,528	4,004	5,555	8,944	4,876	3,021	5,133	(716)	9,972	5,487	(234)
Renewable Curtailment Cost	$000		703	532	454	605	941	497	299	494	(67)	911	443	(17)
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*2.00*	*4.00*	*2.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,402,750	1,495,261	1,165,375	1,163,668	1,234,034	1,268,266	1,140,506	1,016,217	1,001,155	993,006	902,248	752,105
Regasification fixed costs	$000		-	-	84,246	92,788	91,051	92,926	92,865	90,618	92,710	90,669	92,582	89,545
O&M	$000		175,102	166,992	181,741	180,898	155,058	145,033	147,721	154,409	152,811	152,031	138,570	119,986
Purchased power	$000		737,437	728,652	688,293	685,533	685,101	678,995	668,900	654,100	641,684	652,720	656,017	690,816
Renewables	$000		69,543	71,174	72,858	75,670	78,509	78,465	78,465	78,465	78,541	78,465	78,496	78,465
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	221,474	220,587	235,133	254,839	364,891	402,822
Total System Costs	**$000**		2,395,498	2,501,944	2,297,267	2,321,712	2,421,121	2,483,561	2,349,931	2,214,394	2,202,033	2,221,730	2,232,804	2,133,739
Present Value of Total System Costs	**$000**		2,317,302	2,264,843	1,946,012	1,840,417	1,795,966	1,723,971	1,526,455	1,346,039	1,252,564	1,182,609	852,843	584,828
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		59%	60%	51%	50%	51%	51%	49%	46%	45%	45%	40%	35%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	8%	6%	6%	6%	7%	7%	7%	6%	6%
Purchased power	*percent*		31%	29%	30%	30%	28%	27%	28%	30%	29%	29%	29%	32%
Renewables	*percent*		3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%
Amortized capital costs	*percent*		0%	2%	5%	5%	7%	9%	9%	10%	11%	11%	16%	19%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-16: P3F2 S2 Model Results (Renewables Freeze Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 2; Sensivity 2

IRP Metrics Analysis

		Fiscal Year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*28,419,453*	2,310,868	2,227,173	2,082,907	2,047,371	1,913,409	1,843,125	1,774,858	1,631,011	1,543,809	1,424,371	942,111	694,078
System Costs	*$000*	*2,569,135*	2,388,847	2,460,330	2,458,870	2,582,788	2,579,446	2,655,215	2,732,340	2,683,207	2,714,046	2,675,920	2,466,514	2,532,339
Capital Costs (FY 2016 - 2025)	*$ million*	3,715	134	176	167	239	433	1,287	663	184	183	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	959												
Capital Costs (FY 2016 - 2035)	*$ million*	4,674												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*2.49%*	*2.56%*	*2.62%*	*2.79%*	*2.98%*	*2.99%*	*3.01%*	*3.01%*	*3.02%*	*3.02%*	*3.03%*	*3.04%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*3.28%*	*3.52%*	*3.74%*	*4.03%*	*4.36%*	*4.51%*	*4.67%*	*4.80%*	*4.93%*	*5.05%*	*5.71%*	*6.36%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.5%*	*0.3%*	*1.0%*	*1.0%*	*1.7%*	*0.9%*	*0.5%*	*0.8%*	*0.1%*	*0.5%*	*0.1%*	*0.0%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		8,445	1,734	6,410	6,876	12,411	7,075	3,842	6,152	982	4,575	676	84
Renewable Curtailment Cost	$000		1,036	204	726	749	1,306	722	381	592	92	418	54	6
LOLH	*hours*		*0.00*	*0.00*	*3.00*	*0.00*	*4.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*68%*	*70%*	*69%*	*61%*	*59%*	*96%*	*88%*	*60%*	*61%*	*63%*	*61%*	*61%*
Reserve Margin (without GTs & Cambalache)	*percent*		*28%*	*29%*	*29%*	*25%*	*24%*	*38%*	*36%*	*25%*	*25%*	*26%*	*25%*	*25%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,393,347	1,456,073	1,489,930	1,585,887	1,530,692	1,520,599	1,502,039	1,512,524	1,536,319	1,468,304	1,177,515	1,219,758
Regasification fixed costs	$000		-	-	7,933	11,822	15,753	15,827	15,855	15,703	12,175	15,989	18,395	18,957
O&M	$000		175,500	175,171	172,392	168,045	148,133	162,274	167,448	160,989	161,277	159,100	158,610	157,835
Purchased power	$000		739,791	733,560	676,434	683,640	678,597	673,456	671,135	660,674	656,335	664,956	670,435	694,262
Renewables	$000		69,543	71,174	72,858	75,670	78,509	78,465	78,465	78,465	78,541	78,465	78,496	78,465
Amortized capital costs	$000		10,667	24,351	39,323	57,723	127,761	204,594	297,399	254,854	269,399	289,105	363,063	363,063
Total System Costs	**$000**		2,388,847	2,460,330	2,458,870	2,582,788	2,579,446	2,655,215	2,732,340	2,683,207	2,714,046	2,675,920	2,466,514	2,532,339
Present Value of Total System Costs	**$000**		2,310,868	2,227,173	2,082,907	2,047,371	1,913,409	1,843,125	1,774,858	1,631,011	1,543,809	1,424,371	942,111	694,078
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	59%	61%	61%	59%	57%	55%	56%	57%	55%	48%	48%
Regasification fixed costs	*percent*		0%	0%	0%	0%	1%	1%	1%	1%	0%	1%	1%	1%
O&M	*percent*		7%	7%	7%	7%	6%	6%	6%	6%	6%	6%	6%	6%
Purchased power	*percent*		31%	30%	28%	26%	26%	25%	25%	25%	24%	25%	27%	27%
Renewables	*percent*		3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Amortized capital costs	*percent*		0%	1%	2%	2%	5%	8%	11%	9%	10%	11%	15%	14%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-17: P3F3 S2 Model Results (Renewables Freeze Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 3; Sensitivity 2

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*25,279,759*	2,326,425	2,263,752	1,954,754	1,835,817	1,797,759	1,734,145	1,528,303	1,333,328	1,266,056	1,143,050	808,321	588,483
System Costs	*$000*	*2,242,899*	2,404,929	2,500,739	2,307,586	2,315,910	2,423,538	2,498,217	2,352,777	2,193,484	2,225,751	2,147,412	2,116,244	2,147,077
Capital Costs (FY 2016 - 2025)	*$ million*	4,766	134	240	615	239	239	865	399	1,116	672	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	950												
Capital Costs (FY 2016 - 2035)	*$ million*	5,716												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*2.49%*	*2.56%*	*2.62%*	*2.79%*	*2.98%*	*2.99%*	*3.01%*	*3.01%*	*3.02%*	*3.02%*	*3.03%*	*3.04%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*3.28%*	*3.52%*	*3.74%*	*4.03%*	*4.36%*	*4.51%*	*4.67%*	*4.80%*	*4.93%*	*5.05%*	*5.71%*	*6.36%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.0%*	*0.9%*	*0.6%*	*1.4%*	*0.2%*	*0.9%*	*0.5%*	*2.4%*	*0.5%*	*0.3%*	*0.0%*	*0.0%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		5,705	5,334	3,682	9,284	1,346	7,059	3,808	18,901	4,199	2,559	183	36
Renewable Curtailment Cost	$000		700	626	417	1,011	142	720	377	1,820	394	234	15	3
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*4.00*	*3.00*	*6.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*

System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,406,629	1,491,994	1,175,915	1,155,565	1,236,122	1,285,988	1,140,868	924,008	853,373	822,892	713,065	720,840
Regasification fixed costs	$000		-	-	84,245	92,910	91,009	93,011	92,868	100,839	93,061	99,234	96,249	96,077
O&M	$000		175,018	166,634	182,415	180,911	155,506	145,489	148,108	153,187	157,620	135,389	117,804	117,334
Purchased power	$000		743,072	731,072	687,398	687,698	685,023	675,388	669,478	635,067	634,153	639,895	665,862	689,593
Renewables	$000		69,543	71,174	72,858	75,670	78,509	78,465	78,465	78,465	78,541	78,465	78,496	78,465
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	222,990	301,918	409,002	371,537	444,768	444,768
Total System Costs	**$000**		2,404,929	2,500,739	2,307,586	2,315,910	2,423,538	2,498,217	2,352,777	2,193,484	2,225,751	2,147,412	2,116,244	2,147,077
Present Value of Total System Costs	**$000**		2,326,425	2,263,752	1,954,754	1,835,817	1,797,759	1,734,145	1,528,303	1,333,328	1,266,056	1,143,050	808,321	588,483

Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	60%	51%	50%	51%	51%	48%	42%	38%	38%	34%	34%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	5%	4%	5%	5%	4%
O&M	*percent*		7%	7%	8%	8%	6%	6%	6%	7%	7%	6%	6%	5%
Purchased power	*percent*		31%	29%	30%	30%	28%	27%	28%	29%	28%	30%	31%	32%
Renewables	*percent*		3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%
Amortized capital costs	*percent*		0%	2%	5%	5%	7%	9%	9%	14%	18%	17%	21%	21%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-18: P3F4 S2 Model Results (Renewables Freeze Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 4; Sensitivity 2

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*25,232,859*	2,316,391	2,248,103	1,931,068	1,828,404	1,783,739	1,703,099	1,504,422	1,327,149	1,232,230	1,178,401	840,851	571,015
System Costs	*$000*	*2,241,016*	2,394,556	2,483,451	2,279,625	2,306,557	2,404,638	2,453,492	2,316,013	2,183,318	2,166,285	2,213,825	2,201,409	2,083,342
Capital Costs (FY 2016 - 2025)	*$ million*	3,329	134	240	615	239	239	865	382	184	183	248	462	-
Capital Costs (FY 2026 - 2035)	*$ million*	1,923												
Capital Costs (FY 2016 - 2035)	*$ million*	5,252												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*2.50%*	*2.57%*	*2.64%*	*2.81%*	*3.01%*	*3.03%*	*3.05%*	*3.09%*	*3.14%*	*3.15%*	*3.22%*	*3.27%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*3.33%*	*3.59%*	*3.89%*	*4.35%*	*4.84%*	*5.16%*	*5.48%*	*5.84%*	*6.21%*	*6.51%*	*8.11%*	*9.63%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.1%*	*1.1%*	*0.4%*	*1.0%*	*1.2%*	*0.9%*	*0.0%*	*0.8%*	*0.8%*	*1.3%*	*0.7%*	*0.0%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		6,078	6,690	2,620	7,408	9,502	7,484	124	7,756	8,498	14,137	8,841	30
Renewable Curtailment Cost	*$000*		735	773	287	753	906	672	11	624	650	1,030	521	2
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*15.00*	*4.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*71%*	*71%*	*71%*	*64%*	*68%*	*56%*	*66%*	*68%*	*68%*	*63%*	*59%*
Reserve Margin (without GTs & Cambalache)	*percent*		*30%*	*31%*	*31%*	*31%*	*28%*	*29%*	*24%*	*29%*	*29%*	*29%*	*27%*	*25%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,401,889	1,477,192	1,150,699	1,150,559	1,219,020	1,241,154	1,107,417	987,846	969,098	987,769	880,355	708,507
Regasification fixed costs	$000		-	-	84,239	92,771	91,020	92,893	92,773	90,681	92,723	90,647	92,571	89,187
O&M	$000		175,078	166,623	181,241	180,260	154,753	143,845	146,646	153,462	151,284	151,585	137,193	118,006
Purchased power	$000		737,380	728,598	685,833	684,142	683,968	677,258	669,238	652,279	639,506	650,521	647,903	686,355
Renewables	$000		69,543	71,174	72,858	75,670	78,509	78,465	78,465	78,465	78,541	78,465	78,496	78,465
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	221,474	220,587	235,133	254,839	364,891	402,822
Total System Costs	**$000**		2,394,556	2,483,451	2,279,625	2,306,557	2,404,638	2,453,492	2,316,013	2,183,318	2,166,285	2,213,825	2,201,409	2,083,342
Present Value of Total System Costs	**$000**		2,316,391	2,248,103	1,931,068	1,828,404	1,783,739	1,703,099	1,504,422	1,327,149	1,232,230	1,178,401	840,851	571,015
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		59%	59%	50%	50%	51%	51%	48%	45%	45%	45%	40%	34%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	8%	6%	6%	6%	7%	7%	7%	6%	6%
Purchased power	*percent*		31%	29%	30%	30%	28%	28%	29%	30%	30%	29%	29%	33%
Renewables	*percent*		3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%
Amortized capital costs	*percent*		0%	2%	5%	5%	7%	9%	10%	10%	11%	12%	17%	19%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-19: P3F1 S3 Model Results (No Renewal of AES Contract Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 1; Sensitivity 3

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,967,150*	2,324,415	2,284,681	1,986,538	1,905,851	1,873,112	1,780,291	1,598,369	1,430,835	1,338,332	1,267,861	964,166	656,350
System Costs	*$000*	*2,433,301*	2,402,851	2,523,859	2,345,107	2,404,259	2,525,121	2,564,696	2,460,641	2,353,895	2,352,815	2,381,891	2,524,257	2,394,688
Capital Costs (FY 2016 - 2025)	*$ million*	3,329	134	240	615	239	239	865	382	184	183	248	462	-
Capital Costs (FY 2026 - 2035)	*$ million*	1,923												
Capital Costs (FY 2016 - 2035)	*$ million*	5,252												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.69%*	*6.20%*	*8.01%*	*9.71%*	*10.47%*	*10.75%*	*11.21%*	*11.82%*	*12.51%*	*13.99%*	*15.77%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*3.96%*	*5.55%*	*7.19%*	*9.09%*	*10.89%*	*11.76%*	*12.15%*	*12.73%*	*13.45%*	*14.26%*	*16.44%*	*18.75%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.0%*	*0.7%*	*1.1%*	*2.6%*	*3.1%*	*2.3%*	*1.6%*	*3.0%*	*5.9%*	*6.3%*	*2.1%*	*0.4%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		6,944	6,958	12,707	39,617	55,819	45,779	32,565	63,711	128,877	143,635	56,026	11,265
Renewable Curtailment Cost	$000		927	970	1,813	5,782	8,306	6,838	4,835	9,428	19,061	21,264	8,031	1,597
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*2.00*	*4.00*	*2.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*

System Costs Summary	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Fuel	$000		1,390,916	1,464,670	1,119,658	1,110,153	1,164,497	1,156,953	1,049,550	949,534	934,740	922,022	1,144,927	936,016
Regasification fixed costs	$000		-	-	84,194	92,638	90,919	92,883	92,717	90,750	92,668	90,672	90,634	89,377
O&M	$000		174,853	166,298	179,279	177,976	152,337	141,463	144,977	151,123	149,288	148,665	146,893	129,298
Purchased power	$000		735,761	720,987	682,963	675,136	666,665	658,665	650,387	630,472	615,387	624,128	394,550	405,217
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,363	431,958
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	221,474	220,587	235,133	254,839	364,891	402,822
Total System Costs	**$000**		2,402,851	2,523,859	2,345,107	2,404,259	2,525,121	2,564,696	2,460,641	2,353,895	2,352,815	2,381,891	2,524,257	2,394,688
Present Value of Total System Costs	**$000**		2,324,415	2,284,681	1,986,538	1,905,851	1,873,112	1,780,291	1,598,369	1,430,835	1,338,332	1,267,861	964,166	656,350

Percentage of System Costs	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Fuel	*percent*		58%	58%	48%	46%	46%	45%	43%	40%	40%	39%	45%	39%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	6%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	26%	27%	26%	26%	16%	17%
Renewables	*percent*		4%	5%	7%	9%	11%	11%	12%	13%	14%	14%	15%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	9%	9%	9%	10%	11%	14%	17%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-20: P3F2 S3 Model Results (No Renewal of AES Contract Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 2; Sensitivity 3

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*30,057,326*	2,317,231	2,245,720	2,117,647	2,093,813	1,990,775	1,909,027	1,819,372	1,670,345	1,586,814	1,465,713	1,105,829	819,821
System Costs	*$000*	*2,773,981*	2,395,425	2,480,819	2,499,881	2,641,375	2,683,742	2,750,153	2,800,868	2,747,917	2,789,651	2,753,588	2,895,142	2,991,109
Capital Costs (FY 2016 - 2025)	*$ million*	3,715	134	176	167	239	433	1,287	663	184	183	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	959												
Capital Costs (FY 2016 - 2035)	*$ million*	4,674												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*10.48%*	*10.77%*	*11.10%*	*11.58%*	*12.12%*	*13.53%*	*15.25%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*11.89%*	*12.29%*	*12.74%*	*13.33%*	*13.97%*	*15.91%*	*18.14%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.5%*	*0.8%*	*2.5%*	*2.3%*	*5.9%*	*3.4%*	*0.4%*	*0.3%*	*0.3%*	*0.5%*	*0.1%*	*0.8%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		10,045	7,694	30,390	35,686	108,641	68,045	7,432	5,352	7,252	10,905	1,386	23,744
Renewable Curtailment Cost	$000		1,319	1,057	4,281	5,148	15,993	10,054	1,091	783	1,060	1,594	199	3,366
LOLH	*hours*		*0.00*	*0.00*	*3.00*	*0.00*	*4.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*68%*	*70%*	*69%*	*61%*	*60%*	*97%*	*90%*	*60%*	*61%*	*63%*	*45%*	*45%*
Reserve Margin (without GTs & Cambalache)	*percent*		*28%*	*29%*	*29%*	*25%*	*25%*	*39%*	*37%*	*25%*	*25%*	*26%*	*17%*	*17%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,381,750	1,424,302	1,437,205	1,508,000	1,462,561	1,421,181	1,360,466	1,354,920	1,378,722	1,299,239	1,506,707	1,552,029
Regasification fixed costs	$000		-	-	7,919	11,860	15,545	15,725	15,803	15,704	12,105	15,858	18,572	19,003
O&M	$000		175,187	174,458	171,396	166,443	146,874	159,648	163,908	157,447	158,004	155,258	165,946	164,867
Purchased power	$000		737,167	725,668	669,779	672,149	657,666	654,149	661,756	653,564	645,822	652,561	458,491	460,188
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,363	431,958
Amortized capital costs	$000		10,667	24,351	39,323	57,723	127,761	204,594	297,399	254,854	269,399	289,105	363,063	363,063
Total System Costs	**$000**		2,395,425	2,480,819	2,499,881	2,641,375	2,683,742	2,750,153	2,800,868	2,747,917	2,789,651	2,753,588	2,895,142	2,991,109
Present Value of Total System Costs	**$000**		2,317,231	2,245,720	2,117,647	2,093,813	1,990,775	1,909,027	1,819,372	1,670,345	1,586,814	1,465,713	1,105,829	819,821
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	57%	57%	57%	54%	52%	49%	49%	49%	47%	52%	52%
Regasification fixed costs	*percent*		0%	0%	0%	0%	1%	1%	1%	1%	0%	1%	1%	1%
O&M	*percent*		7%	7%	7%	6%	5%	6%	6%	6%	6%	6%	6%	6%
Purchased power	*percent*		31%	29%	27%	25%	25%	24%	24%	24%	23%	24%	16%	15%
Renewables	*percent*		4%	5%	7%	9%	10%	11%	11%	11%	12%	12%	13%	14%
Amortized capital costs	*percent*		0%	1%	2%	2%	5%	7%	11%	9%	10%	10%	13%	12%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-21: P3F3 S3 Model Results (No Renewal of AES Contract Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 3; Sensitivity 3

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,638,397*	2,331,452	2,282,170	1,991,533	1,896,798	1,874,323	1,785,184	1,595,430	1,430,127	1,360,560	1,249,544	882,554	648,810
System Costs	*$000*	*2,389,625*	2,410,125	2,521,085	2,351,004	2,392,837	2,526,753	2,571,745	2,456,116	2,352,729	2,391,892	2,347,480	2,310,592	2,367,177
Capital Costs (FY 2016 - 2025)	*$ million*	4,766	134	240	615	239	239	865	399	1,116	672	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	950												
Capital Costs (FY 2016 - 2035)	*$ million*	5,716												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*10.48%*	*10.77%*	*11.10%*	*11.58%*	*12.12%*	*13.53%*	*15.25%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*11.89%*	*12.29%*	*12.74%*	*13.33%*	*13.97%*	*15.91%*	*18.14%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.0%*	*0.9%*	*1.1%*	*2.9%*	*3.2%*	*2.8%*	*2.1%*	*7.5%*	*5.3%*	*10.4%*	*0.2%*	*1.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		6,465	8,634	14,092	45,394	58,646	55,789	42,148	158,861	118,159	241,789	5,563	35,696
Renewable Curtailment Cost	$000		849	1,186	1,985	6,549	8,633	8,243	6,187	23,230	17,264	35,353	797	5,060
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*4.00*	*3.00*	*6.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*67%*	*63%*	*65%*	*54%*	*64%*	*73%*	*51%*	*47%*	*46%*
Reserve Margin (without GTs & Cambalache	*percent*		*30%*	*30%*	*30%*	*29%*	*27%*	*28%*	*23%*	*27%*	*31%*	*21%*	*19%*	*19%*

System Costs Summary	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Fuel	$000		1,392,104	1,460,050	1,125,720	1,096,226	1,164,725	1,165,836	1,043,801	875,449	800,249	794,780	865,927	868,361
Regasification fixed costs	$000		-	-	84,167	92,849	90,853	92,825	92,750	101,050	93,063	99,680	100,471	100,701
O&M	$000		174,747	165,935	179,940	177,741	152,612	141,909	144,830	149,985	154,297	133,160	125,833	124,744
Purchased power	$000		741,954	723,198	682,163	677,666	667,862	656,441	650,210	612,898	609,681	606,756	391,230	396,645
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,363	431,958
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	222,990	301,918	409,002	371,537	444,768	444,768
Total System Costs	**$000**		2,410,125	2,521,085	2,351,004	2,392,837	2,526,753	2,571,745	2,456,116	2,352,729	2,391,892	2,347,480	2,310,592	2,367,177
Present Value of Total System Costs	**$000**		2,331,452	2,282,170	1,991,533	1,896,798	1,874,323	1,785,184	1,595,430	1,430,127	1,360,560	1,249,544	882,554	648,810

Percentage of System Costs	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Fuel	*percent*		58%	58%	48%	46%	46%	45%	42%	37%	33%	34%	37%	37%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	5%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	26%	26%	25%	26%	17%	17%
Renewables	*percent*		4%	5%	7%	9%	11%	11%	12%	13%	14%	15%	17%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	9%	9%	13%	17%	16%	19%	19%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-22: P3F4 S3 Model Results (No Renewal of AES Contract Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 3; Future 4; Sensitivity 3

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,751,330*	2,321,778	2,263,686	1,980,026	1,890,766	1,857,038	1,761,577	1,583,768	1,414,429	1,325,421	1,267,453	948,640	645,935
System Costs	*$000*	*2,411,389*	2,400,125	2,500,666	2,337,420	2,385,229	2,503,452	2,537,736	2,438,163	2,326,904	2,330,116	2,381,124	2,483,607	2,356,688
Capital Costs (FY 2016 - 2025)	*$ million*	3,329	134	240	615	239	239	865	382	184	183	248	462	-
Capital Costs (FY 2026 - 2035)	*$ million*	1,923												
Capital Costs (FY 2016 - 2035)	*$ million*	5,252												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.73%*	*6.25%*	*8.09%*	*9.82%*	*10.61%*	*10.92%*	*11.41%*	*12.05%*	*12.64%*	*14.40%*	*16.38%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.07%*	*5.73%*	*7.46%*	*9.54%*	*11.52%*	*12.58%*	*13.15%*	*13.92%*	*14.84%*	*15.67%*	*18.72%*	*21.87%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.0%*	*0.8%*	*1.2%*	*2.8%*	*3.7%*	*3.3%*	*2.6%*	*3.8%*	*7.6%*	*8.0%*	*3.7%*	*1.1%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		7,099	7,613	14,898	45,423	71,975	68,037	57,052	85,784	181,979	202,404	110,183	39,061
Renewable Curtailment Cost	$000		921	1,035	2,062	6,353	10,178	9,558	7,874	11,677	24,539	27,114	13,956	4,774
LOLH	*hours*		*0.00*	*0.00*	*0.00*	*0.00*	*15.00*	*4.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*71%*	*71%*	*71%*	*64%*	*68%*	*56%*	*66%*	*68%*	*68%*	*49%*	*47%*
Reserve Margin (without GTs & Cambalache	*percent*		*30%*	*31%*	*31%*	*31%*	*28%*	*29%*	*24%*	*29%*	*29%*	*29%*	*20%*	*19%*

System Costs Summary	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Fuel	$000		1,388,350	1,441,651	1,113,927	1,093,852	1,147,193	1,133,311	1,031,787	926,616	917,508	924,834	1,108,812	905,954
Regasification fixed costs	$000		-	-	84,181	92,635	90,787	92,896	92,686	90,727	92,675	90,650	90,600	89,707
O&M	$000		174,769	165,729	179,298	177,339	151,524	141,041	144,369	150,250	148,407	148,371	145,512	127,815
Purchased power	$000		735,685	721,382	681,001	673,047	663,245	655,754	646,310	627,295	610,794	620,864	391,445	398,444
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,349	431,946
Amortized capital costs	$000		10,667	39,864	104,755	123,155	177,368	219,877	221,474	220,587	235,133	254,839	364,891	402,822
Total System Costs	**$000**		2,400,125	2,500,666	2,337,420	2,385,229	2,503,452	2,537,736	2,438,163	2,326,904	2,330,116	2,381,124	2,483,607	2,356,688
Present Value of Total System Costs	**$000**		2,321,778	2,263,686	1,980,026	1,890,766	1,857,038	1,761,577	1,583,768	1,414,429	1,325,421	1,267,453	948,640	645,935

Percentage of System Costs	Unit	Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Fuel	*percent*		58%	58%	48%	46%	46%	45%	42%	40%	39%	39%	45%	38%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	6%	5%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	27%	27%	26%	26%	16%	17%
Renewables	*percent*		4%	5%	7%	9%	11%	12%	12%	13%	14%	14%	15%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	9%	9%	9%	10%	11%	15%	17%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-23: P2F1 S3 Model Results (No Renewal of AES Contract Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 2; Future 1; Sensitivity 3

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*27,014,718*	2,321,260	2,275,588	1,996,412	1,894,910	1,879,368	1,785,732	1,615,353	1,430,696	1,346,440	1,262,673	927,019	665,931
System Costs	*$000*	*2,440,073*	2,399,590	2,513,814	2,356,763	2,390,456	2,533,555	2,572,534	2,486,787	2,353,666	2,367,068	2,372,144	2,427,003	2,429,644
Capital Costs (FY 2016 - 2025)	*$ million*	3,314	134	240	615	239	363	725	382	184	183	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	2,223												
Capital Costs (FY 2016 - 2035)	*$ million*	5,536												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.69%*	*6.20%*	*8.01%*	*9.71%*	*10.47%*	*10.75%*	*11.21%*	*11.82%*	*12.51%*	*13.99%*	*15.77%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*3.96%*	*5.55%*	*7.19%*	*9.09%*	*10.89%*	*11.76%*	*12.15%*	*12.73%*	*13.45%*	*14.26%*	*16.44%*	*18.75%*
OPERATIONS														
Renewable Curtailment	*percent*		*0.9%*	*0.5%*	*1.2%*	*1.8%*	*3.7%*	*2.7%*	*1.7%*	*2.5%*	*5.8%*	*5.3%*	*1.6%*	*0.0%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		6,210	4,418	14,901	27,845	67,159	53,496	34,604	53,231	127,513	120,674	41,436	895
Renewable Curtailment Cost	$000		829	616	2,127	4,064	9,993	7,991	5,138	7,877	18,859	17,865	5,940	127
LOLH	*hours*		*6.00*	*0.00*	*0.00*	*0.00*	*0.00*	*3.00*	*7.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*70%*	*63%*	*62%*	*50%*	*60%*	*62%*	*63%*	*54%*	*50%*
Reserve Margin (without GTs & Cambalache	*percent*		*30%*	*30%*	*30%*	*30%*	*27%*	*27%*	*21%*	*26%*	*26%*	*27%*	*23%*	*20%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,387,784	1,453,108	1,132,991	1,091,896	1,165,404	1,165,023	1,077,493	950,220	952,665	914,720	1,040,282	919,044
Regasification fixed costs	$000		-	-	84,129	92,773	91,195	92,730	92,414	90,820	92,684	90,631	92,523	88,227
O&M	$000		175,455	165,870	180,569	177,847	152,540	142,046	144,235	149,218	147,710	146,863	158,375	147,080
Purchased power	$000		735,030	722,933	680,060	679,584	663,573	659,252	650,884	632,643	614,528	624,775	398,362	417,420
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,363	431,958
Amortized capital costs	$000		10,667	39,864	104,755	123,155	187,509	218,627	220,224	219,338	233,883	253,590	355,098	425,915
Total System Costs	**$000**		2,399,590	2,513,814	2,356,763	2,390,456	2,533,555	2,572,534	2,486,787	2,353,666	2,367,068	2,372,144	2,427,003	2,429,644
Present Value of Total System Costs	**$000**		2,321,260	2,275,588	1,996,412	1,894,910	1,879,368	1,785,732	1,615,353	1,430,696	1,346,440	1,262,673	927,019	665,931
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	46%	46%	45%	43%	40%	40%	39%	43%	38%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	7%	6%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	26%	27%	26%	26%	16%	17%
Renewables	*percent*		4%	5%	7%	9%	11%	11%	12%	13%	14%	14%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	8%	9%	9%	10%	11%	15%	18%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-24: P2F3 S3 Model Results (No Renewal of AES Contract Sensitivity)

Puerto Rico Electric Power Authority
Portfolio 2; Future 3; Sensitivity 3
IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,857,661*	2,318,387	2,274,849	1,975,075	1,928,520	1,870,390	1,787,709	1,618,611	1,441,792	1,343,298	1,300,555	896,659	659,551
System Costs	*$000*	*2,417,732*	2,396,620	2,512,998	2,331,575	2,432,855	2,521,452	2,575,382	2,491,803	2,371,920	2,361,544	2,443,312	2,347,520	2,406,368
Capital Costs (FY 2016 - 2025)	*$ million*	5,097	134	240	615	239	363	725	382	1,102	587	709	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	894												
Capital Costs (FY 2016 - 2035)	*$ million*	5,992												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.70%*	*6.20%*	*8.02%*	*9.72%*	*10.48%*	*10.77%*	*11.10%*	*11.58%*	*12.12%*	*13.53%*	*15.25%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.02%*	*5.64%*	*7.28%*	*9.20%*	*11.00%*	*11.89%*	*12.29%*	*12.74%*	*13.33%*	*13.97%*	*15.91%*	*18.14%*
OPERATIONS														
Renewable Curtailment	*percent*		*1.2%*	*0.6%*	*1.5%*	*1.9%*	*4.7%*	*2.7%*	*2.3%*	*10.6%*	*6.4%*	*4.6%*	*0.1%*	*0.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		8,465	5,276	18,754	29,047	86,388	53,523	46,396	224,677	140,848	106,284	2,982	7,280
Renewable Curtailment Cost	$000		1,111	725	2,642	4,191	12,717	7,908	6,810	32,854	20,579	15,540	427	1,032
LOLH	*hours*		*2.00*	*0.00*	*0.00*	*3.00*	*0.00*	*6.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*70%*	*70%*	*70%*	*63%*	*62%*	*50%*	*60%*	*75%*	*89%*	*65%*	*64%*
Reserve Margin (without GTs & Cambalache	*percent*		*30%*	*30%*	*30%*	*30%*	*27%*	*27%*	*21%*	*26%*	*32%*	*37%*	*27%*	*26%*
System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,386,168	1,452,850	1,108,089	1,133,523	1,155,718	1,169,132	1,084,777	908,317	834,537	771,843	846,690	853,282
Regasification fixed costs	$000		-	-	85,142	89,337	92,837	92,840	92,750	102,445	96,174	93,420	98,903	98,439
O&M	$000		175,559	165,776	179,551	179,855	151,866	141,788	143,724	146,567	153,877	159,636	142,675	141,084
Purchased power	$000		733,573	722,468	679,780	681,784	660,189	658,139	648,792	604,988	605,791	621,232	409,755	414,471
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,363	431,958
Amortized capital costs	$000		10,667	39,864	104,755	123,155	187,509	218,627	220,224	298,174	345,568	455,616	467,134	467,134
Total System Costs	**$000**		2,396,620	2,512,998	2,331,575	2,432,855	2,521,452	2,575,382	2,491,803	2,371,920	2,361,544	2,443,312	2,347,520	2,406,368
Present Value of Total System Costs	**$000**		2,318,387	2,274,849	1,975,075	1,928,520	1,870,390	1,787,709	1,618,611	1,441,792	1,343,298	1,300,555	896,659	659,551
Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	47%	46%	45%	44%	38%	35%	32%	36%	35%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	7%	7%	6%	6%
Purchased power	*percent*		31%	29%	29%	28%	26%	26%	26%	26%	26%	25%	17%	17%
Renewables	*percent*		4%	5%	7%	9%	11%	11%	12%	13%	14%	14%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	8%	9%	13%	15%	19%	20%	19%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix C-25: P2F4 S3 Model Results (No Renewal of AES Contract Sensitivity)

Puerto Rico Electric Power Authority

Portfolio 2; Future 4; Sensitivity 3

IRP Metrics Analysis

		Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
COST	**Unit**	**Total / Average**												
Present Value of System Costs	*$000*	*26,856,602*	2,318,016	2,259,899	1,981,466	1,881,561	1,870,045	1,762,580	1,595,165	1,420,900	1,331,435	1,273,287	920,684	655,567
System Costs	*$000*	*2,425,659*	2,396,236	2,496,483	2,339,120	2,373,616	2,520,986	2,539,181	2,455,708	2,337,550	2,340,688	2,392,084	2,410,417	2,391,831
Capital Costs (FY 2016 - 2025)	*$ million*	3,314	134	240	615	239	363	725	382	184	183	248	-	-
Capital Costs (FY 2026 - 2035)	*$ million*	2,223												
Capital Costs (FY 2016 - 2035)	*$ million*	5,536												
ENVIRONMENTAL COMPLIANCE														
RPS (PPOA/Net sales)	*percent*		*3.24%*	*4.73%*	*6.25%*	*8.09%*	*9.82%*	*10.61%*	*10.92%*	*11.41%*	*12.05%*	*12.64%*	*14.40%*	*16.38%*
RPS Target	*percent*		*12.00%*	*12.75%*	*13.50%*	*14.25%*	*15.00%*	*15.33%*	*15.67%*	*16.00%*	*16.33%*	*16.67%*	*18.33%*	*20%*
Reduced RPS Target	*percent*		*8.00%*	*8.50%*	*9.00%*	*9.50%*	*10.00%*	*10.40%*	*10.80%*	*11.20%*	*11.60%*	*12.00%*	*13.50%*	*15%*
Renewable Penetration	*percent*		*4.07%*	*5.73%*	*7.46%*	*9.54%*	*11.52%*	*12.58%*	*13.15%*	*13.92%*	*14.84%*	*15.67%*	*18.72%*	*21.87%*
OPERATIONS														
Renewable Curtailment	*percent*		*0.8%*	*0.8%*	*1.3%*	*2.2%*	*4.3%*	*3.6%*	*2.9%*	*4.1%*	*7.5%*	*8.2%*	*2.8%*	*0.2%*
Renewable Curtailment Limit	*percent*		*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Renewable Curtailed Energy	*MWh*		5,609	7,213	16,223	35,401	83,097	75,220	63,767	92,422	180,829	207,036	82,785	7,750
Renewable Curtailment Cost	$000		728	981	2,245	4,951	11,750	10,567	8,801	12,581	24,384	27,734	10,486	947
LOLH	*hours*		*6.00*	*0.00*	*0.00*	*0.00*	*6.00*	*6.00*	*9.00*	*0.00*	*1.00*	*0.00*	*0.00*	*0.00*
Reserve Margin	*percent*		*70%*	*71%*	*71%*	*71%*	*64%*	*63%*	*51%*	*61%*	*63%*	*62%*	*55%*	*50%*
Reserve Margin (without GTs & Cambalache)	*percent*		*30%*	*31%*	*31%*	*31%*	*28%*	*27%*	*21%*	*26%*	*27%*	*27%*	*23%*	*21%*

System Costs Summary	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	$000		1,383,637	1,437,656	1,116,108	1,078,637	1,157,585	1,135,635	1,054,397	939,927	931,456	938,868	1,030,265	889,944
Regasification fixed costs	$000		-	-	84,191	92,736	90,944	92,918	92,735	90,723	92,712	90,671	92,586	88,035
O&M	$000		175,509	165,393	179,522	176,908	152,009	141,275	143,015	148,675	147,259	147,223	156,747	144,727
Purchased power	$000		735,770	721,531	680,285	676,979	659,605	655,869	643,800	627,458	609,780	620,167	393,373	411,263
Renewables	$000		90,654	132,039	174,259	225,201	273,334	294,856	301,536	311,428	325,599	341,566	382,349	431,946
Amortized capital costs	$000		10,667	39,864	104,755	123,155	187,509	218,627	220,224	219,338	233,883	253,590	355,098	425,915
Total System Costs	**$000**		2,396,236	2,496,483	2,339,120	2,373,616	2,520,986	2,539,181	2,455,708	2,337,550	2,340,688	2,392,084	2,410,417	2,391,831
Present Value of Total System Costs	**$000**		2,318,016	2,259,899	1,981,466	1,881,561	1,870,045	1,762,580	1,595,165	1,420,900	1,331,435	1,273,287	920,684	655,567

Percentage of System Costs	**Unit**	**Fiscal Year**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**
Fuel	*percent*		58%	58%	48%	45%	46%	45%	43%	40%	40%	39%	43%	37%
Regasification fixed costs	*percent*		0%	0%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
O&M	*percent*		7%	7%	8%	7%	6%	6%	6%	6%	6%	6%	7%	6%
Purchased power	*percent*		31%	29%	29%	29%	26%	26%	26%	27%	26%	26%	16%	17%
Renewables	*percent*		4%	5%	7%	9%	11%	12%	12%	13%	14%	14%	16%	18%
Amortized capital costs	*percent*		0%	2%	4%	5%	7%	9%	9%	9%	10%	11%	15%	18%
Total	***percent***		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix

D

Emission Summary

Appendix D-1: P1F1 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 1; Future 1

Emissions Summary

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs/MWh*	*1,421*	*1,403*	*1,289*	*1,254*	*1,256*	*1,125*	*1,066*	*1,052*
CO_2 Emission Target (Total Generation)	*lbs/MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Aguirre 1 CC Repower	*lbs/MWh*	-	-	-	-	-	*946*	*932*	*938*
Aguirre 2 CC Repower	*lbs/MWh*	-	-	-	-	-	*989*	*962*	*970*
CO_2 Emissions (Aguirre 1 ST HFCC Repower)	*lbs/MWh*	-	-	-	-	-	-	*1,121*	*1,120*
CO_2 Emissions (Aguirre 2 ST HFCC Repower)	*lbs/MWh*	-	-	-	-	-	-	*1,139*	*1,137*
CO_2 Emissions (Costa Sur 5 HFCC Repower)	*lbs/MWh*	-	-	-	-	-	-	*1,091*	*1,091*
CO_2 Emissions (Costa Sur 6 HFCC Repower)	*lbs/MWh*	-	-	-	-	-	-	*1,121*	*1,122*
CO_2 Emission Mass									
PREPA Owned Existing Generation	Metric ton	8,374,876	8,226,147	7,100,385	6,905,368	6,878,060	4,083,859	77,291	106,179
Fossil Fueled PPOA Generation	Metric ton	4,847,063	4,822,356	4,873,981	4,776,007	4,679,553	4,728,319	4,589,539	4,547,579
Repowered Generation	Metric ton	-	-	-	-	-	1,330,409	5,077,560	5,050,680
New Generation	Metric ton	-	-	-	-	-	148,890	27,231	38,944
Total	Metric ton	13,221,939	13,048,502	11,974,366	11,681,375	11,557,613	10,291,477	9,771,621	9,743,383
Other Emissions									
FPM Emission	lbs	28,731,628	28,452,323	26,924,126	25,899,353	25,804,882	24,854,796	24,178,034	24,162,045
Existing units	*lbs*	4,091,370	3,916,132	1,912,991	1,722,500	1,959,773	373,933	12,541	17,229
New units (including repower)	*lbs*	-	-	-	-	-	149,069	396,669	396,386
Purchased power	*lbs*	24,640,258	24,536,191	25,011,135	24,176,853	23,845,110	24,331,794	23,768,824	23,748,431
NO_X Emission	lbs	56,883,307	58,784,199	57,936,614	56,484,993	56,342,641	46,397,338	42,737,780	43,454,321
Existing units	*lbs*	36,143,061	38,157,136	37,162,280	36,013,379	36,338,708	26,005,306	919,676	1,263,418
New units (including repower)	*lbs*	-	-	-	-	-	262,172	22,331,464	22,950,656
Purchased power	*lbs*	20,740,246	20,627,063	20,774,334	20,471,614	20,003,933	20,129,860	19,486,641	19,240,247
SO_X Emission	lbs	49,309,285	47,046,998	29,293,827	27,497,542	29,702,897	14,819,438	14,099,067	14,160,483
Existing units	*lbs*	37,844,352	35,630,414	17,655,555	16,248,564	18,607,753	3,394,315	52,777	72,503
New units (including repower)	*lbs*	-	-	-	-	-	102,739	2,985,383	3,035,924
Purchased power	*lbs*	11,464,934	11,416,584	11,638,271	11,248,978	11,095,145	11,322,384	11,060,907	11,052,056

Appendix D-2: P1F3 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 1; Future 3

IRP Metrics Analysis

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs/MWh*	*1,420*	*1,397*	*1,289*	*1,256*	*1,256*	*1,077*	*1,044*	*1,028*
CO_2 Emission Target (Total Generation)	*lbs/MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Palo Seco SCC-800 Train 1	*lbs/MWh*	-	-	-	-	-	*948*	*948*	*951*
Palo Seco SCC-800 Train 2	*lbs/MWh*	-	-	-	-	-	*953*	*950*	*954*
Palo Seco SCC-800 Train 3	*lbs/MWh*	-	-	-	-	-	*948*	*952*	*951*
Aguirre 1 CC Repower	*lbs/MWh*	-	-	-	-	-	*974*	*970*	*968*
Aguirre 2 CC Repower	*lbs/MWh*	-	-	-	-	-	*1,027*	*1,019*	*1,015*
CO_2 Emission Mass									
PREPA Owned Existing Generation	*Metric tons*	8,345,921	8,194,973	7,062,961	6,925,461	6,911,695	2,104,450	1,043,995	988,819
Fossil Fueled PPOA Generation	*Metric tons*	4,863,104	4,797,540	4,914,584	4,778,938	4,651,889	4,632,852	4,422,235	4,395,757
Repowered Generation	*Metric tons*	-	-	-	-	-	2,766,735	3,812,914	3,848,989
New Generation	*Metric tons*	-	-	-	-	-	373,985	376,304	376,426
Total	*Metric tons*	13,209,026	12,992,513	11,977,545	11,704,399	11,563,584	9,878,022	9,655,448	9,609,991
Other Emissions									
FPM Emission	lbs	28,772,614	28,092,584	27,126,698	25,992,905	25,591,182	24,097,688	23,274,165	23,199,583
Existing units	*lbs*	4,018,387	3,829,721	1,812,529	1,772,761	1,993,387	181,289	38,295	38,258
New units (including repower)	*lbs*	-	-	-	-	-	168,430	310,628	312,936
Purchased power	*lbs*	24,754,228	24,262,864	25,314,169	24,220,145	23,597,795	23,747,970	22,925,242	22,848,390
NO_X Emission	lbs	57,947,763	59,627,210	59,084,712	56,077,118	56,100,686	43,098,865	32,943,271	32,918,961
Existing units	*lbs*	37,150,108	39,055,332	38,170,120	35,602,804	36,178,159	12,703,966	3,332,903	3,269,599
New units (including repower)	*lbs*	-	-	-	-	-	10,639,407	10,842,015	11,014,316
Purchased power	*lbs*	20,797,654	20,571,878	20,914,592	20,474,314	19,922,526	19,755,492	18,768,354	18,635,046
SO_X Emission	lbs	48,103,300	46,406,070	28,136,470	28,171,107	29,844,564	12,764,533	10,705,570	10,680,817
Existing units	*lbs*	36,585,231	35,117,148	16,356,881	16,901,892	18,864,845	1,714,123	5,017	15,477
New units (including repower)	*lbs*	-	-	-	-	-	-	32,134	32,488
Purchased power	*lbs*	11,518,070	11,288,921	11,779,589	11,269,215	10,979,719	11,050,410	10,668,419	10,632,851

Appendix D-3: P2F1 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 2; Future 1

Emissios Summary

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs/MWh*	*1,427*	*1,408*	*1,295*	*1,257*	*1,261*	*1,126*	*1,047*	*971*
CO_2 Emission Target (Total Generation)	*lbs/MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Aguirre 1 CC Repower	*lbs/MWh*	-	-	-	-	-	*954*	*952*	*988*
Aguirre 2 CC Repower	*lbs/MWh*	-	-	-	-	-	*992*	*982*	*970*
Aguirre F Class Train 1	*lbs/MWh*	-	-	-	-	-	-	*890*	*865*
Aguirre F Class Train 2	*lbs/MWh*	-	-	-	-	-	-	*909*	*875*
Aguirre F Class Train 3	*lbs/MWh*	-	-	-	-	-	-	*934*	*877*
Costa Sur F Class Train 1	*lbs/MWh*	-	-	-	-	-	-	-	*884*
Costa Sur F Class Train 2	*lbs/MWh*	-	-	-	-	-	-	-	*903*
CO_2 Emission Mass		13,276,644	13,087,462	12,038,290	11,704,443	11,605,416	9,864,469	7,555,890	5,366,742
PREPA Owned Existing Generation	Metric ton	8,441,325	8,273,853	7,183,436	6,885,906	6,965,663	3,883,736	1,747,766	16,311
Fossil Fueled PPOA Generation	Metric ton	4,835,319	4,813,609	4,854,854	4,818,538	4,639,753	4,671,063	4,666,388	4,911,955
Repowered Generation	Metric ton	-	-	-	-	-	1,309,670	1,141,736	438,477
New Generation	Metric ton	-	-	-	-	-	116,927	1,721,016	3,231,766
Total	Metric ton	13,276,644	13,087,462	12,038,290	11,704,443	11,605,416	9,981,396	9,276,906	8,598,509
Other Emissions									
FPM Emission	lbs	28,685,206	28,406,051	26,867,270	26,125,911	25,720,218	24,567,990	24,703,077	25,836,242
Existing units	*lbs*	4,155,060	3,951,819	1,925,981	1,687,135	2,007,829	367,752	213,033	2,647
New units (including repower)	*lbs*	-	-	-	-	-	137,024	221,855	279,299
Purchased power	*lbs*	24,530,145	24,454,232	24,941,290	24,438,776	23,712,389	24,063,214	24,268,189	25,554,296
NO_X Emission	lbs	56,635,061	58,806,462	58,553,608	56,642,248	56,120,437	44,241,278	30,294,045	21,642,462
Existing units	*lbs*	35,927,595	38,203,831	37,870,610	36,004,490	36,310,925	24,112,682	10,021,820	194,082
New units (including repower)	*lbs*	-	-	-	-	-	251,524	494,416	632,876
Purchased power	*lbs*	20,707,466	20,602,631	20,682,998	20,637,758	19,809,513	19,877,071	19,777,810	20,815,503
SO_X Emission	lbs	49,774,858	47,280,160	29,383,704	27,255,399	30,052,668	14,627,605	11,329,849	11,910,826
Existing units	*lbs*	38,361,325	35,901,835	17,777,841	15,884,400	19,019,047	3,349,432	19,419	11,138
New units (including repower)	*lbs*	-	-	-	-	-	80,683	16,814	7,534
Purchased power	*lbs*	11,413,533	11,378,325	11,605,863	11,370,999	11,033,620	11,197,490	11,293,616	11,892,154

Appendix D-4: P2F2 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 2; Future 2

IRP Metrics Analysis

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs./MWh*	*1,409*	*1,377*	*1,374*	*1,335*	*1,343*	*1,168*	*1,056*	*1,042*
CO_2 Emission Target (Total Generation)	*lbs./MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Costa Sur F Class Train 1	*lbs/MWh*	-	-	-	-	-	-	*856*	*858*
Costa Sur F Class Train 2	*lbs/MWh*	-	-	-	-	-	-	*860*	*862*
CO_2 Emission Mass		13,109,254	12,807,409	12,775,528	12,441,347	12,386,692	7,998,207	5,207,846	5,272,213
PREPA Owned Existing Generation	Metric ton	8,272,575	8,016,560	8,041,534	7,823,787	7,779,330	2,773,841	28,800	47,184
Fossil Fueled PPOA Generation	Metric ton	4,836,679	4,790,849	4,733,994	4,617,560	4,539,326	4,978,983	4,948,552	4,915,273
Repowered Generation	Metric ton	-	-	-	-	68,035	245,383	230,495	309,756
New Generation	Metric ton	-	-	-	-	-	2,289,124	4,122,356	3,952,919
Total	Metric ton	13,109,254	12,807,409	12,775,528	12,441,347	12,386,692	10,287,331	9,330,202	9,225,132
Other Emissions									
FPM Emission	lbs.	28,473,347	27,840,621	27,999,538	26,798,145	26,978,007	26,977,363	26,804,848	26,666,638
Existing units	*lbs.*	3,871,256	3,591,072	3,698,208	3,375,493	3,714,861	350,986	4,673	7,656
New units (including repower)	*lbs.*	-	-	-	-	22,311	831,156	878,526	886,296
Purchased power	*lbs.*	24,602,091	24,249,549	24,301,330	23,422,652	23,240,835	25,795,221	25,921,650	25,772,687
NO_X Emission	lbs.	56,186,771	55,497,101	56,181,963	56,367,216	53,715,544	37,772,239	22,108,857	22,165,499
Existing units	*lbs.*	35,496,023	34,961,028	36,007,264	36,591,364	34,334,202	16,074,312	342,683	561,439
New units (including repower)	*lbs.*	-	-	-	-	15,060	561,030	856,897	844,190
Purchased power	*lbs.*	20,690,748	20,536,072	20,174,699	19,775,853	19,366,282	21,136,897	20,909,277	20,759,870
SO_X Emission	lbs.	50,892,290	50,717,984	51,156,408	47,775,294	48,620,598	18,448,707	13,587,362	13,570,459
Existing units	*lbs.*	39,445,067	39,435,190	39,848,396	36,877,070	37,759,312	4,695,891	19,665	32,219
New units (including repower)	*lbs.*	-	-	-	-	46,947	1,748,890	1,504,018	1,543,805
Purchased power	*lbs.*	11,447,223	11,282,795	11,308,012	10,898,224	10,814,340	12,003,926	12,063,678	11,994,435

Appendix D-5: P2F3 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 2; Future 3

Emissions Summary

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs/MWh*	*1,430*	*1,401*	*1,288*	*1,272*	*1,253*	*1,056*	*984*	*967*
CO_2 Emission Target (Total Generation)	*lbs/MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Palo Seco SCC-800 Train 1	*lbs/MWh*	-	-	-	-	-	*985*	*1,173*	*1,091*
Palo Seco SCC-800 Train 2	*lbs/MWh*	-	-	-	-	-	*1,001*	*1,217*	*1,137*
Palo Seco SCC-800 Train 3	*lbs/MWh*	-	-	-	-	-	*1,024*	*1,225*	*1,224*
Aguirre 1 CC Repower	*lbs/MWh*	-	-	-	-	-	*1,031*	*1,151*	*1,100*
Aguirre 2 CC Repower	*lbs/MWh*	-	-	-	-	-	*1,120*	*1,035*	*1,183*
Aguirre F Class Train 1 San Juan Site	*lbs/MWh*	-	-	-	-	-	*923*	*861*	*868*
Aguirre F Class Train 2 Aguirre Site	*lbs/MWh*	-	-	-	-	-	*958*	*871*	*877*
Aguirre F Class Train 3 Aguirre Site	*lbs/MWh*	-	-	-	-	-	-	*878*	*879*
Costa Sur F Class Train 1	*lbs/MWh*	-	-	-	-	-	-	*912*	*897*
Costa Sur F Class Train 2	*lbs/MWh*	-	-	-	-	-	-	*938*	*922*
CO_2 Emission Mass									
PREPA Owned Existing Generation	Metric ton	8,471,439	8,228,769	7,121,948	6,984,354	6,955,896	2,760,310	716,373	685,058
Fossil Fueled PPOA Generation	Metric ton	4,838,176	4,797,833	4,849,927	4,859,061	4,591,031	4,564,674	4,823,600	4,807,226
Repowered Generation	Metric ton	-	-	-	-	-	717,195	35,501	48,922
New Generation	Metric ton	-	-	-	-	-	1,318,212	3,122,576	3,027,690
Total	Metric ton	13,309,615	13,026,603	11,971,875	11,843,415	11,546,927	9,360,391	8,698,050	8,568,896
Other Emissions									
FPM Emission	lbs	28,829,268	28,196,530	26,746,882	26,619,081	25,315,881	23,527,356	25,318,119	25,310,086
Existing units	*lbs*	4,223,719	3,867,778	1,891,459	1,881,055	1,945,287	141,983	25,715	24,633
New units (including repower)	*lbs*	-	-	-	-	-	153,362	237,952	231,813
Purchased power	*lbs*	24,605,549	24,328,752	24,855,423	24,738,026	23,370,593	23,232,011	25,054,453	25,053,640
NO_X Emission	lbs	55,921,591	59,361,182	57,336,713	57,693,866	55,834,304	36,363,728	25,320,885	25,021,255
Existing units	*lbs*	35,222,999	38,810,363	36,653,721	36,915,021	36,200,658	16,490,598	4,321,785	4,134,820
New units (including repower)	*lbs*	-	-	-	-	-	350,677	544,101	530,065
Purchased power	*lbs*	20,698,592	20,550,819	20,682,992	20,778,845	19,633,646	19,522,452	20,454,999	20,356,370
SO_X Emission	lbs	50,733,836	46,489,230	29,277,107	28,739,652	29,406,678	11,733,955	11,659,817	11,659,921
Existing units	*lbs*	39,285,017	35,169,439	17,711,397	17,229,107	18,532,402	924,176	402	612
New units (including repower)	*lbs*	-	-	-	-	-	-	-	-
Purchased power	*lbs*	11,448,819	11,319,791	11,565,710	11,510,545	10,874,276	10,809,779	11,659,414	11,659,309

Appendix D-6: P2F4 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 2; Future 4

Emissions Summary

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs/MWh*	*1,427*	*1,406*	*1,292*	*1,253*	*1,256*	*1,114*	*1,027*	*944*
CO_2 Emission Target (Total Generation)	*lbs/MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Aguirre 1 CC Repower	*lbs/MWh*	-	-	-	-	-	*955*	*955*	*950*
Aguirre 2 CC Repower	*lbs/MWh*	-	-	-	-	-	*1,001*	*986*	*954*
Aguirre F Class Train 1	*lbs/MWh*	-	-	-	-	-	-	*895*	*868*
Aguirre F Class Train 2	*lbs/MWh*	-	-	-	-	-	-	*909*	*875*
Aguirre F Class Train 3	*lbs/MWh*	-	-	-	-	-	-	*925*	*872*
Costa Sur F Class Train 1	*lbs/MWh*	-	-	-	-	-	-	-	*885*
Costa Sur F Class Train 2	*lbs/MWh*	-	-	-	-	-	-	-	*906*
CO_2 Emission Mass									
PREPA Owned Existing Generation	Metric ton	8,425,988	8,183,685	7,079,524	6,817,097	6,907,598	3,969,535	1,794,411	30,819
Fossil Fueled PPOA Generation	Metric ton	4,846,639	4,815,774	4,857,322	4,790,524	4,594,371	4,613,112	4,584,198	4,754,012
Repowered Generation	Metric ton	-	-	-	-	-	1,266,113	1,113,422	531,830
New Generation	Metric ton	-	-	-	-	-	125,795	1,590,055	3,004,503
Total	Metric ton	13,272,628	12,999,458	11,936,846	11,607,621	11,501,969	9,974,555	9,082,086	8,321,164
Other Emissions									
FPM Emission	lbs	28,766,498	28,415,019	26,830,807	26,025,072	25,522,764	24,221,062	24,235,550	25,257,790
Existing units	*lbs*	4,152,079	3,902,964	1,925,730	1,710,728	2,008,625	361,148	232,841	5,001
New units (including repower)	*lbs*	-	-	-	-	-	136,651	209,509	270,249
Purchased power	*lbs*	24,614,419	24,512,054	24,905,077	24,314,344	23,514,140	23,723,262	23,793,200	24,982,540
NO_X Emission	lbs	56,463,377	58,376,846	57,780,947	55,689,462	55,546,995	45,359,577	30,132,420	21,036,290
Existing units	*lbs*	35,716,732	37,781,180	37,070,494	35,177,803	35,942,918	25,468,780	10,219,580	366,712
New units (including repower)	*lbs*	-	-	-	-	-	245,982	466,907	610,008
Purchased power	*lbs*	20,746,645	20,595,666	20,710,454	20,511,659	19,604,077	19,644,815	19,445,933	20,059,570
SO_X Emission	lbs	49,801,800	46,872,092	29,216,648	27,267,117	29,846,649	14,512,925	14,144,571	11,658,303
Existing units	*lbs*	38,348,967	35,466,708	17,627,795	15,953,955	18,905,165	3,386,958	3,056,280	21,044
New units (including repower)	*lbs*	-	-	-	-	-	86,803	15,872	10,374
Purchased power	*lbs*	11,452,833	11,405,384	11,588,853	11,313,161	10,941,484	11,039,163	11,072,420	11,626,885

Appendix D-7: P3F1 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 3; Future 1

Emissions Summary

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs/MWh*	*1,425*	*1,407*	*1,290*	*1,262*	*1,262*	*1,123*	*1,044*	*962*
CO_2 Emission Target (Total Generation)	*lbs/MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Aguirre 1 CC Repower	*lbs/MWh*	-	-	-	-	-	*949*	*961*	*974*
Aguirre 2 CC Repower	*lbs/MWh*	-	-	-	-	-	*996*	*1,005*	*983*
Aguirre H Class Train 1	*lbs/MWh*	-	-	-	-	-	-	*852*	*830*
Aguirre H Class Train 2	*lbs/MWh*	-	-	-	-	-	-	*872*	*844*
Costa Sur H Class Train 1	*lbs/MWh*	-	-	-	-	-	-	-	*855*
Costa Sur H Class Train 2	*lbs/MWh*	-	-	-	-	-	-	-	*858*
CO_2 Emission Mass									
PREPA Owned Existing Generation	Metric ton	8,401,594	8,308,604	7,087,655	7,012,308	6,927,433	3,761,986	2,107,623	85,735
Fossil Fueled PPOA Generation	Metric ton	4,859,454	4,778,966	4,902,579	4,749,069	4,676,496	4,665,005	4,474,963	4,730,057
Repowered Generation	Metric ton	-	-	-	-	-	1,316,771	1,193,246	730,577
New Generation	Metric ton	-	-	-	-	-	222,211	1,538,503	2,991,664
Total	Metric ton	13,261,048	13,087,570	11,990,234	11,761,376	11,603,929	9,965,973	9,314,335	8,538,033
Other Emissions									
FPM Emission	lbs	28,789,390	28,151,257	27,032,609	25,877,157	25,807,274	24,545,817	23,715,561	25,274,901
Existing units	*lbs*	4,065,363	3,944,163	1,829,966	1,872,692	2,013,495	339,660	271,150	13,911
New units (including repower)	*lbs*	-	-	-	-	-	172,086	231,294	296,940
Purchased power	*lbs*	24,724,028	24,207,094	25,202,643	24,004,465	23,793,779	24,034,071	23,213,117	24,964,050
NO_X Emission	lbs	57,642,808	59,356,285	58,795,541	55,786,880	56,297,121	43,371,103	31,632,949	21,585,932
Existing units	*lbs*	36,856,740	38,877,280	37,914,823	35,418,254	36,293,868	23,244,476	12,170,248	1,020,151
New units (including repower)	*lbs*	-	-	-	-	-	276,052	475,596	644,501
Purchased power	*lbs*	20,786,068	20,479,005	20,880,717	20,368,626	20,003,253	19,850,574	18,987,105	19,921,279
SO_X Emission	lbs	48,938,312	47,056,683	28,303,449	28,796,276	29,970,459	14,628,154	10,912,620	11,722,188
Existing units	*lbs*	37,434,332	35,793,584	16,575,918	17,627,625	18,899,316	3,290,887	40,624	58,543
New units (including repower)	*lbs*	-	-	-	-	-	153,332	69,567	45,024
Purchased power	*lbs*	11,503,980	11,263,099	11,727,531	11,168,651	11,071,143	11,183,935	10,802,430	11,618,622

Appendix D-8: P3F2 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 3; Future 2

Emissions Summary

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs./MWh*	*1,433*	*1,413*	*1,394*	*1,382*	*1,350*	*1,175*	*1,027*	*1,007*
CO_2 Emission Target (Total Generation)	*lbs./MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Costa Sur H Class Train 1	*lbs/MWh*	-	-	-	-	-	-	*816*	*818*
Costa Sur H Class Train 2	*lbs/MWh*	-	-	-	-	-	-	*828*	*831*
CO_2 Emission Mass									
PREPA Owned Existing Generation	Metric ton	8,486,079	8,326,533	8,266,504	8,161,853	7,835,998	3,046,340	93,789	134,663
Fossil Fueled PPOA Generation	Metric ton	4,851,147	4,813,509	4,706,248	4,710,425	4,549,996	4,986,658	4,840,544	4,787,038
Repowered Generation	Metric ton	-	-	-	-	69,023	1,041,229	967,395	881,036
New Generation	Metric ton	-	-	-	-	-	1,280,520	3,174,545	3,128,736
Total	Metric ton	13,337,226	13,140,042	12,972,752	12,872,278	12,455,016	10,354,747	9,076,274	8,931,473
Other Emissions									
FPM Emission	lbs.	29,035,810	28,602,825	28,148,844	27,998,162	27,061,386	27,156,459	26,026,330	25,800,317
Existing units	*lbs.*	4,289,458	4,242,674	4,171,279	4,095,077	3,951,282	836,669	15,218	21,850
New units (including repower)	*lbs.*	-	-	-	-	22,635	761,383	858,611	807,428
Purchased power	*lbs.*	24,746,353	24,360,152	23,977,565	23,903,085	23,087,468	25,558,406	25,152,501	24,971,039
NO_X Emission	lbs.	55,071,182	54,488,431	54,467,258	58,026,181	51,574,700	36,637,407	22,459,143	22,654,385
Existing units	*lbs.*	34,343,026	33,853,806	34,347,970	37,855,854	32,075,546	14,858,158	1,115,988	1,602,338
New units (including repower)	*lbs.*	-	-	-	-	15,279	513,934	819,777	788,998
Purchased power	*lbs.*	20,728,156	20,634,625	20,119,287	20,170,327	19,483,875	21,265,315	20,523,378	20,263,049
SO_X Emission	lbs.	51,903,488	51,303,725	50,765,572	49,148,484	48,184,577	18,353,625	13,262,148	13,093,305
Existing units	*lbs.*	40,388,908	39,969,483	39,608,808	38,026,690	37,394,655	4,858,717	64,042	91,952
New units (including repower)	*lbs.*	-	-	-	-	47,628	1,602,079	1,493,031	1,380,411
Purchased power	*lbs.*	11,514,581	11,334,242	11,156,764	11,121,794	10,742,294	11,892,829	11,705,075	11,620,942

Appendix D-9: P3F3 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 3; Future 3

Emissions Summary

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs/MWh*	*1,396*	*1,360*	*1,280*	*1,258*	*1,257*	*995*	*940*	*919*
CO_2 Emission Target (Total Generation)	*lbs/MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Palo Seco F Class Train 1	*lbs/MWh*	-	-	-	-	-	*970*	*938*	*924*
Aguirre 1 CC Repower	*lbs/MWh*	-	-	-	-	-	*1,136*	*1,088*	*1,074*
Aguirre 2 CC Repower	*lbs/MWh*	-	-	-	-	-	*1,133*	*1,051*	*1,047*
Aguirre H Class Train 1	*lbs/MWh*	-	-	-	-	-	*852*	*830*	*834*
Aguirre H Class Train 2	*lbs/MWh*	-	-	-	-	-	*871*	*847*	*851*
Costa Sur H Class Train 1	*lbs/MWh*	-	-	-	-	-	-	*857*	*853*
Costa Sur H Class Train 2	*lbs/MWh*	-	-	-	-	-	-	*855*	*850*
CO_2 Emission Mass									
PREPA Owned Existing Generation	Metric ton	8,119,610	7,863,671	6,993,619	6,927,918	6,861,265	2,006,286	186,668	162,094
Fossil Fueled PPOA Generation	Metric ton	4,867,958	4,782,596	4,907,272	4,791,834	4,704,246	4,410,071	4,709,964	4,654,340
Repowered Generation	Metric ton	-	-	-	-	-	560,838	195,124	142,842
New Generation	Metric ton	-	-	-	-	-	1,903,379	3,221,357	3,199,771
Total	Metric ton	12,987,568	12,646,267	11,900,891	11,719,752	11,565,511	8,880,574	8,313,114	8,159,047
Other Emissions									
FPM Emission	lbs	28,828,077	28,007,946	27,113,901	26,114,191	25,998,698	22,981,435	24,768,825	24,574,426
Existing units	*lbs*	4,047,686	3,855,191	1,837,259	1,776,335	2,016,032	226,774	16,164	15,848
New units (including repower)	*lbs*	-	-	-	-	-	185,671	202,798	194,513
Purchased power	*lbs*	24,780,391	24,152,754	25,276,641	24,337,856	23,982,665	22,568,991	24,549,862	24,364,065
NO_X Emission	lbs	57,948,375	59,882,891	59,075,925	55,944,504	56,428,644	33,241,268	31,283,699	31,338,907
Existing units	*lbs*	37,130,468	39,363,133	38,192,500	35,433,079	36,323,218	13,998,394	2,665,448	2,602,289
New units (including repower)	*lbs*	-	-	-	-	-	424,557	8,674,825	9,064,806
Purchased power	*lbs*	20,817,907	20,519,758	20,883,425	20,511,425	20,105,426	18,818,318	19,943,427	19,671,811
SO_X Emission	lbs	48,322,196	46,530,339	28,341,790	28,096,765	30,150,778	13,146,824	11,427,396	11,341,704
Existing units	*lbs*	36,791,947	35,292,764	16,579,663	16,772,608	18,991,590	2,645,137	2,522	2,959
New units (including repower)	*lbs*	-	-	-	-	-	-	-	-
Purchased power	*lbs*	11,530,248	11,237,576	11,762,127	11,324,157	11,159,188	10,501,687	11,424,874	11,338,745

Appendix D-10: P3F4 Emission Summary

Puerto Rico Electric Power Authority

Portfolio 3; Future 4

Emissions Summary

		2016	2017	2018	2019	2020	2025	2030	2035
CO_2 Emission Rates									
CO_2 Emissions (Total Generation)	*lbs/MWh*	*1,424*	*1,406*	*1,288*	*1,257*	*1,254*	*1,110*	*1,025*	*938*
CO_2 Emission Target (Total Generation)	*lbs/MWh*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,470*	*1,413*	*1,413*
Aguirre 1 CC Repower	*lbs/MWh*	-	-	-	-	-	*952*	*962*	*944*
Aguirre 2 CC Repower	*lbs/MWh*	-	-	-	-	-	*1,000*	*998*	*967*
Aguirre H Class Train 1	*lbs/MWh*	-	-	-	-	-	-	*855*	*845*
Aguirre H Class Train 2	*lbs/MWh*	-	-	-	-	-	-	*872*	*848*
Costa Sur H Class Train 1	*lbs/MWh*	-	-	-	-	-	-	-	*849*
Costa Sur H Class Train 2	*lbs/MWh*	-	-	-	-	-	-	-	*848*
CO_2 Emission Mass									
PREPA Owned Existing Generation	Metric ton	8,388,472	8,203,594	7,036,531	6,918,602	6,840,617	3,820,199	2,125,001	81,142
Fossil Fueled PPOA Generation	Metric ton	4,858,938	4,795,704	4,867,693	4,724,884	4,637,266	4,621,876	4,411,231	4,551,409
Repowered Generation	Metric ton	-	-	-	-	-	1,279,464	1,143,432	874,193
New Generation	Metric ton	-	-	-	-	-	213,615	1,473,728	2,782,291
Total	Metric ton	13,247,410	12,999,298	11,904,224	11,643,486	11,477,883	9,935,155	9,153,391	8,289,035
Other Emissions									
FPM Emission	lbs	28,781,324	28,249,863	26,779,060	25,717,256	25,614,839	24,284,413	23,479,317	24,836,594
Existing units	*lbs*	4,059,907	3,910,432	1,816,119	1,825,781	1,988,578	347,389	276,802	13,166
New units (including repower)	*lbs*	-	-	-	-	-	166,456	221,824	295,498
Purchased power	*lbs*	24,721,417	24,339,431	24,962,941	23,891,475	23,626,260	23,770,568	22,980,690	24,527,930
NO_X Emission	lbs	57,546,911	58,460,502	58,560,546	55,276,184	55,488,402	43,599,584	31,444,950	20,592,633
Existing units	*lbs*	36,763,052	37,926,248	37,807,495	35,014,492	35,664,068	23,650,501	12,306,589	965,504
New units (including repower)	*lbs*	-	-	-	-	-	267,722	455,692	633,854
Purchased power	*lbs*	20,783,859	20,534,255	20,753,051	20,261,692	19,824,334	19,681,361	18,682,670	18,993,274
SO_X Emission	lbs	48,892,148	46,863,981	28,032,586	28,352,731	29,712,095	14,512,353	10,808,597	11,527,285
Existing units	*lbs*	37,389,383	35,539,150	16,416,792	17,236,622	18,718,792	3,303,769	46,727	55,407
New units (including repower)	*lbs*	-	-	-	-	-	147,401	67,284	54,620
Purchased power	*lbs*	11,502,765	11,324,831	11,615,794	11,116,110	10,993,303	11,061,183	10,694,586	11,417,258

Appendix

E

Load and Resource Balances

Appendix E- 1: P1F1 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 1; Future 1 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	*MW*	*2,969*	*2,967*	*2,964*	*2,968*	*2,932*	*2,920*	*2,907*	*2,908*	*2,910*	*2,912*	*2,920*	*2,927*
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,752	2,752	3,272	3,272	3,012	2,752	2,120	2,120	2,120	2,120	400	400
PREPA Owned Thermal Generation - Peaker	*MW*	720	720	200	200	200	200	200	200	200	200	200	200
PREPA Owned Thermal Generation - Cambalache	*MW*	166	166	166	166	166	166	166	166	166	166	166	166
PREPA Owned Thermal Generation - Old GT	*MW*	378	378	378	378	378	378	378	378	378	378	378	378
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
Total PREPA Owned Existing Generation	***MW***	**4,075**	**4,075**	**4,075**	**4,075**	**3,815**	**3,555**	**2,923**	**2,923**	**2,923**	**2,923**	**1,203**	**1,203**
New Thermal Generation Resources (2)													
SCC-800 at Palo Seco (train 1)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
SCC-800 at Palo Seco (train 2)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
SCC-800 at Palo Seco (train 3)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	263	263	263	263	263	263
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	0	263	263	263	263	263
Aguirre 1 Steam Unit Replacement (HFCC Repower)	*MW*	0	0	0	0	0	0	0	0	0	0	543	543
Aguirre 2 Steam Unit Replacement (HFCC Repower)	*MW*	0	0	0	0	0	0	0	0	0	0	543	543
Costa Sur 5 Steam Unit Replacement (HFCC Repower)	*MW*	0	0	0	0	0	0	0	0	0	0	503	503
Costa Sur 6 Steam Unit Replacement (HFCC Repower)	*MW*	0	0	0	0	0	0	0	0	0	0	503	503
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**0**	**210**	**474**	**737**	**737**	**737**	**2,828**	**2,828**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	750	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,036***	***5,036***	***5,036***	***5,036***	***4,776***	***4,727***	***4,358***	***4,622***	***4,622***	***4,622***	***4,992***	***4,992***
Reserve Margin Including Cambalache and Old GTs	*%*	***70%***	***70%***	***70%***	***70%***	***63%***	***62%***	***50%***	***59%***	***59%***	***59%***	***71%***	***71%***
Reserve Margin Excluding Cambalache and Old GTs	*%*	***51%***	***51%***	***52%***	***51%***	***44%***	***43%***	***31%***	***40%***	***40%***	***40%***	***52%***	***52%***

Appendix E- 2: P1F3 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 1; Future 3 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	***MW***	***2,969***	***2,967***	***2,964***	***2,968***	***2,932***	***2,920***	***2,907***	***2,908***	***2,910***	***2,912***	***2,920***	***2,927***
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,752	2,752	3,272	3,272	3,012	2,752	2,120	1,670	1,220	810	400	400
PREPA Owned Thermal Generation - Peaker	*MW*	720	720	200	200	200	200	200	200	200	200	200	200
PREPA Owned Thermal Generation - Cambalache	*MW*	165	165	165	165	165	165	165	166	166	166	166	166
PREPA Owned Thermal Generation - Old GT	*MW*	378	378	378	378	378	378	378	378	378	378	378	378
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
SCC-800 at Palo Seco (train 1)	*MW*	0	0	0	0	0	70	70	72	72	72	72	72
SCC-800 at Palo Seco (train 2)	*MW*	0	0	0	0	0	70	70	72	72	72	72	72
SCC-800 at Palo Seco (train 3)	*MW*	0	0	0	0	0	70	70	72	72	72	72	72
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	263	263	263	263	263	263
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	0	263	263	263	263	263
Aguirre 1 Steam Unit Replacement (HFCC Repower)	*MW*	0	0	0	0	0	0	0	0	543	543	543	543
Aguirre 2 Steam Unit Replacement (HFCC Repower)	*MW*	0	0	0	0	0	0	0	0	0	0	543	543
Costa Sur 5 Steam Unit Replacement (HFCC Repower)	*MW*	0	0	0	0	0	0	0	0	0	0	503	503
Costa Sur 6 Steam Unit Replacement (HFCC Repower)	*MW*	0	0	0	0	0	0	0	0	0	0	503	503
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**0**	**210**	**474**	**744**	**1,286**	**1,286**	**2,834**	**2,834**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,035***	***5,035***	***5,035***	***5,035***	***4,775***	***4,726***	***4,357***	***4,178***	***4,271***	***3,861***	***4,999***	***4,999***
Reserve Margin Including Cambalache and Old GTs	*%*	***70%***	***70%***	***70%***	***70%***	***63%***	***62%***	***50%***	***44%***	***47%***	***33%***	***71%***	***71%***
Reserve Margin Excluding Cambalache and Old GTs	*%*	***51%***	***51%***	***52%***	***51%***	***44%***	***43%***	***31%***	***25%***	***28%***	***14%***	***53%***	***52%***

Appendix E- 3: P2F1 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 2; Future 1 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	***MW***	***2,969***	***2,967***	***2,964***	***2,968***	***2,932***	***2,920***	***2,907***	***2,883***	***2,861***	***2,837***	***2,846***	***2,853***
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,752	2,752	3,272	3,272	3,012	2,752	2,120	2,120	2,120	2,120	1,220	400
PREPA Owned Thermal Generation - Peaker	*MW*	720	720	200	200	200	200	200	200	200	200	200	200
PREPA Owned Thermal Generation - Cambalache	*MW*	165	165	165	165	165	165	165	165	165	165	165	165
PREPA Owned Thermal Generation - Old GT	*MW*	378	378	378	378	378	378	378	378	378	378	378	378
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
SCC-800 at Palo Seco (train 1)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
SCC-800 at Palo Seco (train 2)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
SCC-800 at Palo Seco (train 3)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	264	264	264	264	264	264
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	0	264	264	264	264	264
Aguirre 1&2 Steam Units Replacement, Train 1 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	370	370
Aguirre 1&2 Steam Units Replacement, Train 2 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	370	370
Aguirre 1&2 Steam Units Replacement, Train 3 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	370	370
Costa Sur 5&6 Steam Units Replacement, Train 1 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	0	369
Costa Sur 5&6 Steam Units Replacement, Train 2 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	0	369
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**0**	**210**	**474**	**737**	**737**	**737**	**1,846**	**2,585**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,035***	***5,035***	***5,035***	***5,035***	***4,775***	***4,726***	***4,357***	***4,621***	***4,621***	***4,621***	***4,830***	***4,748***
Reserve Margin Including Cambalache and Old GTs	*%*	***70%***	***70%***	***70%***	***70%***	***63%***	***62%***	***50%***	***60%***	***62%***	***63%***	***70%***	***66%***
Reserve Margin Excluding Cambalache and Old GTs	*%*	***51%***	***51%***	***52%***	***51%***	***44%***	***43%***	***31%***	***41%***	***43%***	***44%***	***51%***	***47%***

Appendix E- 4: P2F2 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 2; Future 2 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	***MW***	***2,969***	***2,967***	***2,964***	***2,968***	***2,932***	***2,920***	***2,907***	***2,883***	***2,861***	***2,837***	***2,846***	***2,853***
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,693	2,693	2,693	2,693	2,693	2,552	1,920	1,920	1,020	1,020	200	200
PREPA Owned Thermal Generation - Peaker	*MW*	729	729	729	469	209	350	350	350	350	350	350	350
PREPA Owned Thermal Generation - Cambalache	*MW*	165	165	165	165	165	165	165	165	165	165	165	165
PREPA Owned Thermal Generation - Old GT	*MW*	428	428	428	428	428	428	428	428	428	428	428	428
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
SCC-800 at Palo Seco (train 1)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
SCC-800 at Palo Seco (train 2)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
SCC-800 at Palo Seco (train 3)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	255	255	255	255	255	255	255	255
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	255	255	255	255	255	255	255
Aguirre 1&2 Steam Units Replacement at San Juan, Train 1 (F class)	*MW*	0	0	0	0	0	359	359	359	359	359	359	359
Aguirre 1&2 Steam Units Replacement, Train 2 (F class)	*MW*	0	0	0	0	0	0	359	359	359	359	359	359
Aguirre 1&2 Steam Units Replacement, Train 3 (F class)	*MW*	0	0	0	0	0	0	0	359	359	359	359	359
Costa Sur 5&6 Steam Units Replacement, Train 1 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	369	369
Costa Sur 5&6 Steam Units Replacement, Train 2 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	369	369
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**255**	**1,079**	**1,437**	**1,796**	**1,796**	**1,796**	**2,534**	**2,534**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,035***	***5,035***	***5,035***	***4,775***	***4,770***	***5,594***	***5,321***	***5,679***	***4,779***	***4,779***	***4,698***	***4,698***
Reserve Margin Including Cambalache and Old GTs	***%***	***70%***	***70%***	***70%***	***61%***	***63%***	***92%***	***83%***	***97%***	***67%***	***68%***	***65%***	***65%***
Reserve Margin Excluding Cambalache and Old GTs	***%***	***50%***	***50%***	***50%***	***41%***	***42%***	***71%***	***63%***	***76%***	***46%***	***48%***	***44%***	***44%***

Appendix E- 5: P2F3 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 2; Future 3 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	***MW***	***2,969***	***2,967***	***2,964***	***2,968***	***2,932***	***2,920***	***2,907***	***2,883***	***2,861***	***2,837***	***2,846***	***2,853***
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,752	2,752	3,272	3,272	3,012	2,752	2,120	2,120	2,120	1,220	400	400
PREPA Owned Thermal Generation - Peaker	*MW*	720	720	200	200	200	200	200	200	200	200	200	200
PREPA Owned Thermal Generation - Cambalache	*MW*	165	165	165	165	165	165	165	165	165	165	165	165
PREPA Owned Thermal Generation - Old GT	*MW*	378	378	378	378	378	378	378	378	378	378	378	378
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
SCC-800 at Palo Seco (train 1)	*MW*	0	0	0	0	70	70	70	72	72	72	72	72
SCC-800 at Palo Seco (train 2)	*MW*	0	0	0	0	0	70	70	72	72	72	72	72
SCC-800 at Palo Seco (train 3)	*MW*	0	0	0	0	0	70	70	72	72	72	72	72
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	264	264	264	264	264	264	264
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	264	264	264	264	264	264
Aguirre 1&2 Steam Units Replacement at San Juan, Train 1 (F class)	*MW*	0	0	0	0	0	0	0	370	370	370	370	370
Aguirre 1&2 Steam Units Replacement, Train 2 (F class)	*MW*	0	0	0	0	0	0	0	0	370	370	370	370
Aguirre 1&2 Steam Units Replacement, Train 3 (F class)	*MW*	0	0	0	0	0	0	0	0	0	370	370	370
Costa Sur 5&6 Steam Units Replacement, Train 1 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	369	369
Costa Sur 5&6 Steam Units Replacement, Train 2 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	369	369
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**70**	**474**	**737**	**1,113**	**1,482**	**1,852**	**2,591**	**2,591**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,035***	***5,035***	***5,035***	***5,035***	***4,846***	***4,989***	***4,621***	***4,996***	***5,366***	***4,836***	***4,754***	***4,754***
Reserve Margin Including Cambalache and Old GTs	*%*	***70%***	***70%***	***70%***	***70%***	***65%***	***71%***	***59%***	***73%***	***88%***	***70%***	***67%***	***67%***
Reserve Margin Excluding Cambalache and Old GTs	*%*	***51%***	***51%***	***52%***	***51%***	***47%***	***52%***	***40%***	***54%***	***69%***	***51%***	***48%***	***48%***

Appendix E- 6: P2F4 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 2; Future 4 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	*MW*	*2,969*	*2,950*	*2,947*	*2,950*	*2,915*	*2,903*	*2,890*	*2,866*	*2,844*	*2,846*	*2,829*	*2,836*
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,752	2,752	3,272	3,272	3,012	2,752	2,120	2,120	2,120	2,120	1,220	400
PREPA Owned Thermal Generation - Peaker	*MW*	720	720	200	200	200	200	200	200	200	200	200	200
PREPA Owned Thermal Generation - Cambalache	*MW*	165	165	165	165	165	165	165	165	165	165	165	165
PREPA Owned Thermal Generation - Old GT	*MW*	378	378	378	378	378	378	378	378	378	378	378	378
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
SCC-800 at Palo Seco (train 1)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
SCC-800 at Palo Seco (train 2)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
SCC-800 at Palo Seco (train 3)	*MW*	0	0	0	0	0	70	70	70	70	70	70	70
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	264	264	264	264	264	264
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	0	264	264	264	264	264
Aguirre 1&2 Steam Units Replacement, Train 1 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	370	370
Aguirre 1&2 Steam Units Replacement, Train 2 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	370	370
Aguirre 1&2 Steam Units Replacement, Train 3 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	370	370
Costa Sur 5&6 Steam Units Replacement, Train 1 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	0	369
Costa Sur 5&6 Steam Units Replacement, Train 2 (F class)	*MW*	0	0	0	0	0	0	0	0	0	0	0	369
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**0**	**210**	**474**	**737**	**737**	**737**	**1,846**	**2,585**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,035***	***5,035***	***5,035***	***5,035***	***4,775***	***4,726***	***4,357***	***4,621***	***4,621***	***4,621***	***4,830***	***4,748***
Reserve Margin Including Cambalache and Old GTs	*%*	***70%***	***71%***	***71%***	***71%***	***64%***	***63%***	***51%***	***61%***	***62%***	***62%***	***71%***	***67%***
Reserve Margin Excluding Cambalache and Old GTs	*%*	***51%***	***52%***	***52%***	***52%***	***45%***	***44%***	***32%***	***42%***	***43%***	***43%***	***52%***	***48%***

Appendix E- 7: P3F1 Load and Resource Balances

Portfolio 3; Future 1 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	***MW***	***2,969***	***2,967***	***2,964***	***2,968***	***2,932***	***2,920***	***2,907***	***2,883***	***2,861***	***2,837***	***2,846***	***2,853***
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,752	2,752	3,272	3,272	3,012	2,752	2,120	2,120	2,120	2,120	1,220	400
PREPA Owned Thermal Generation - Peaker	*MW*	720	720	200	200	200	200	200	200	200	200	200	200
PREPA Owned Thermal Generation - Cambalache	*MW*	166	166	166	166	166	166	166	166	166	166	166	166
PREPA Owned Thermal Generation - Old GT	*MW*	378	378	378	378	378	378	378	378	378	378	378	378
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
New Generation at Palo Seco (F Class)	*MW*	0	0	0	0	0	359	359	359	359	359	359	359
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	264	264	264	264	264	264
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	0	264	264	264	264	264
Aguirre 1 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	393	393
Aguirre 2 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	393	393
Costa Sur 5 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	0	393
Costa Sur 6 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	0	393
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**0**	**359**	**622**	**886**	**886**	**886**	**1,672**	**2,459**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,036***	***5,036***	***5,036***	***5,036***	***4,776***	***4,875***	***4,506***	***4,770***	***4,770***	***4,770***	***4,656***	***4,623***
Reserve Margin Including Cambalache and Old GTs	*%*	***70%***	***70%***	***70%***	***70%***	***63%***	***67%***	***55%***	***65%***	***67%***	***68%***	***64%***	***62%***
Reserve Margin Excluding Cambalache and Old GTs	*%*	***51%***	***51%***	***52%***	***51%***	***44%***	***48%***	***36%***	***47%***	***48%***	***49%***	***45%***	***43%***

Appendix E- 8: P3F2 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 3; Future 2 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	***MW***	***2,969***	***2,967***	***2,964***	***2,968***	***2,932***	***2,920***	***2,907***	***2,883***	***2,861***	***2,837***	***2,846***	***2,853***
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,693	2,693	2,693	2,693	2,693	2,334	802	802	802	802	-18	-18
PREPA Owned Thermal Generation - Peaker	*MW*	729	729	729	469	209	568	568	568	568	568	568	568
PREPA Owned Thermal Generation - Cambalache	*MW*	166	166	166	166	166	166	166	166	166	166	166	166
PREPA Owned Thermal Generation - Old GT	*MW*	428	428	428	428	428	428	428	428	428	428	428	428
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
New Generation at Palo Seco (F Class)	*MW*	0	0	0	0	0	359	359	359	359	359	359	359
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	255	255	255	255	255	255	255	255
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	255	255	255	255	255	255	255
Aguirre 1 Steam Unit Replacement at San Juan (H class)	*MW*	0	0	0	0	0	382	382	382	382	382	382	382
Aguirre 2 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	382	382	382	382	382	382
Costa Sur 5 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	394	394
Costa Sur 6 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	394	394
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**255**	**1,250**	**1,632**	**1,632**	**1,632**	**1,632**	**2,419**	**2,419**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,036***	***5,036***	***5,036***	***4,776***	***4,771***	***5,766***	***4,616***	***4,616***	***4,616***	***4,616***	***4,584***	***4,584***
Reserve Margin Including Cambalache and Old GTs	***%***	***70%***	***70%***	***70%***	***61%***	***63%***	***97%***	***59%***	***60%***	***61%***	***63%***	***61%***	***61%***
Reserve Margin Excluding Cambalache and Old GTs	***%***	***50%***	***50%***	***50%***	***41%***	***42%***	***77%***	***38%***	***39%***	***41%***	***42%***	***40%***	***40%***

Appendix E- 9: P3F3 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 3; Future 3 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	***MW***	***2,969***	***2,967***	***2,964***	***2,968***	***2,932***	***2,920***	***2,907***	***2,883***	***2,861***	***2,837***	***2,846***	***2,853***
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,752	2,752	3,272	3,272	3,012	3,121	2,489	2,120	2,120	1,220	400	400
PREPA Owned Thermal Generation - Peaker	*MW*	720	720	200	200	200	200	200	200	200	200	200	200
PREPA Owned Thermal Generation - Cambalache	*MW*	165	165	165	165	165	165	165	165	165	165	165	165
PREPA Owned Thermal Generation - Old GT	*MW*	378	378	378	378	378	378	378	378	378	378	378	378
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
New Generation at Palo Seco (F Class)	*MW*	0	0	0	0	0	0	0	369	369	369	369	369
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	264	264	264	264	264	264
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	0	264	264	264	264	264
Aguirre 1 Steam Unit Replacement at San Juan (H class)	*MW*	0	0	0	0	0	0	0	0	393	393	393	393
Aguirre 2 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	393	393	393
Costa Sur 5 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	393	393
Costa Sur 6 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	393	393
San Juan 5&6 Fuel Conversion to NG	***MW***	**0**	**0**	**0**	**0**	**0**	**0**	**264**	**896**	**1,289**	**1,683**	**2,469**	**2,469**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,035***	***5,035***	***5,035***	***5,035***	***4,775***	***4,885***	***4,516***	***4,780***	***5,173***	***4,666***	***4,633***	***4,633***
Reserve Margin Including Cambalache and Old GTs	*%*	***70%***	***70%***	***70%***	***70%***	***63%***	***67%***	***55%***	***66%***	***81%***	***64%***	***63%***	***62%***
Reserve Margin Excluding Cambalache and Old GTs	*%*	***51%***	***51%***	***52%***	***51%***	***44%***	***49%***	***37%***	***47%***	***62%***	***45%***	***44%***	***43%***

Appendix E- 10: P3F4 Load and Resource Balances

Puerto Rico Electric Power Authority

Portfolio 3; Future 4 (Fiscal Year)

Load and Resource Balance

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Peak Demand	***MW***	***2,969***	***2,950***	***2,947***	***2,950***	***2,915***	***2,903***	***2,890***	***2,866***	***2,844***	***2,846***	***2,829***	***2,836***
PREPA Owned Existing Generation Resources (1)													
PREPA Owned Thermal Generation - Base Load	*MW*	2,752	2,752	3,272	3,272	3,012	2,752	2,120	2,120	2,120	2,120	1,220	400
PREPA Owned Thermal Generation - Peaker	*MW*	720	720	200	200	200	200	200	200	200	200	200	200
PREPA Owned Thermal Generation - Cambalache	*MW*	166	166	166	166	166	166	166	166	166	166	166	166
PREPA Owned Thermal Generation - Old GT	*MW*	378	378	378	378	378	378	378	378	378	378	378	378
PREPA Owned Hydro Generation	*MW*	59	59	59	59	59	59	59	59	59	59	59	59
New Thermal Generation Resources (2)													
New Generation at Palo Seco (F Class)	*MW*	0	0	0	0	0	359	359	359	359	359	359	359
Aguirre 1 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	264	264	264	264	264	264
Aguirre 2 CC Unit Gas Turbine Replacement/Repower	*MW*	0	0	0	0	0	0	0	264	264	264	264	264
Aguirre 1 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	393	393
Aguirre 2 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	393	393
Costa Sur 5 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	0	393
Costa Sur 6 Steam Unit Replacement (H class)	*MW*	0	0	0	0	0	0	0	0	0	0	0	393
Total New Thermal Generation	***MW***	**0**	**0**	**0**	**0**	**0**	**359**	**622**	**886**	**886**	**886**	**1,672**	**2,459**
Fossil Fueled PPOAs (3)	*MW*	961	961	961	961	961	961	961	961	961	961	961	961
Renewable PPOAs (4)	*MW*	300	431	576	744	856	876	896	936	976	1,036	1,145	1,309
Total Generation Resources (1) + (2) + (3)	***MW***	***5,036***	***5,036***	***5,036***	***5,036***	***4,776***	***4,875***	***4,506***	***4,770***	***4,770***	***4,770***	***4,656***	***4,623***
Reserve Margin Including Cambalache and Old GTs	*%*	***70%***	***71%***	***71%***	***71%***	***64%***	***68%***	***56%***	***66%***	***68%***	***68%***	***65%***	***63%***
Reserve Margin Excluding Cambalache and Old GTs	*%*	***51%***	***52%***	***52%***	***52%***	***45%***	***49%***	***37%***	***47%***	***49%***	***48%***	***45%***	***44%***

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