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San Juan Power Plant

Prepared for

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55 East Monroe Street
Chicago, IL 60603-5780 USA
312-269-2000
www.sargentlundy.com

Sargent & Lundy

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ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this document has been prepared, reviewed, and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

Contributors

Prepared by:

Name	Title	Section(s) Prepared	Signature	Date
Marc Lemmons	Manager / Boiler Specialist	E.S, 1, 2, 3, 4, 5, 9		
Lara Bledin	Senior Energy Consultant	6		
John Wroble	Principle Energy Consultant	7		
David Helm	Senior Environmental Consultant	8		

Reviewed by:

Name	Title	Section(s) Reviewed	Signature	Date
Kevin Hopkins	Principle Energy Consultant	Overall Report		
Kenneth Snell	Senior Environmental Manager	8		

Approved by:

Thomas Cavalcante
Principal Consultant

Date

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ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	Definition/Clarification
Abengoa	Abengoa, Sevilla, SA [original EPC contractor]
API	American Petroleum Institute
Btu/kWh	British thermal unit per kilowatt hour
CAPEX	capital expenditure
CFR	United States Code of Federal Regulations
DCS	distributed control system
DMR	discharge monitoring reports
EAF	equivalent availability factor
ECHO	Enforcement and Compliance History Online [EPA]
EFH	equivalent fired hours
EFOR	equivalent forced outage rate
EMS	energy management system
EPA	Environmental Protection Agency [United States]
EPC	engineering, procurement, and construction
EPCRA	Emergency Planning and Community Right to Know Act
EQB	Environmental Quality Board [Puerto Rico]
ES	effective starts
ESST	emergency station service transformers
FY	fiscal year
gpm	gallons per minute
GT	gas turbine
GTG	gas turbine generator
HFO	heavy fuel oil
hp	horsepower
HP	high pressure
HRSG	heat recovery steam generator
IRP	integrated resource plan

Acronym/Abbreviation	Definition/Clarification
LP	low pressure
LTSA	long-term service agreement
MATS	mercury and air toxics standards
MHPS	Mitsubishi Hitachi Power Service
MPT	main power transformer
NAAQS	National Ambient Air Quality Standards
NCF	net capacity factor
NOX	nitrogen oxide
NPDES	National Pollution Discharge Elimination System
O&M	operations and maintenance
OEM	original equipment manufacturer
Phase I ESA	Phase I Environmental Site Assessment
Plant	San Juan Steam Plant
PM	particulate matter
PRASA	Puerto Rico Aqueduct and Sewer Authority
PREPA	Puerto Rico Electric Power Authority
PSD	prevention of significant deterioration
psia	pounds per square inch, absolute
psig	pounds per square inch, gage
REC	recognized environmental conditions
RO	reverse osmosis
RFP	request for proposals
San Juan	San Juan Steam Plant
SCR	selective catalytic reduction
SPCC	spill prevention, control, and countermeasure
ST	steam turbine
STG	steam turbine generator
WWTP	wastewater treatment plant

EXECUTIVE SUMMARY

OVERVIEW

The Puerto Rico Electric Power Authority (PREPA) is the electric power company responsible for generating, transmitting, and distributing electricity for the island of Puerto Rico. PREPA engaged Sargent & Lundy to perform an independent technical review of the San Juan Power Plant (“San Juan” or “Plant”).

The Plant is located on the northern coast of Puerto Rico in San Juan. It consists of four thermal steam units and two combined-cycle units with a total nameplate capacity of 864 MW.

This technical report includes an assessment of the plant design, operations and maintenance (O&M) activities, plant organization and personnel, technical performance, commercial arrangements and obligations, and provisions for environmental permitting. Sargent & Lundy understands that this review is connected to the request for proposals (RFP) to manage, operate, maintain, and decommission, as applicable, one or more of the base-load generation plants and gas turbine peaking plants located throughout the island of Puerto Rico, including San Juan.

TECHNICAL REVIEW

The Plant has two main types of power generation units: conventional steam plants (Units 7, 8, 9, and 10) and combined-cycle power blocks (Units 5 and 6).

The four conventional steam plants are fired using heavy fuel oil (HFO) and consist of a Combustion Engineering (now GE Power) natural circulation boiler, a General Electric condensing steam turbine (ST) generator, and supporting auxiliary equipment. Each generator is rated for 133,689 kVA, and each unit (Units 7, 8, 9, and 10) is rated at 100 MW. Construction of the Plant began in the early 1950s and continued with Unit 7 going into commercial service in 1965 and the last thermal unit, Unit 10, beginning commercial service in 1968.

The combined-cycle blocks are among PREPA’s newest, beginning commercial operation in October 2008. The Plant is comprised of two combined-cycle units (Units 5 and 6) in a 1x1 configuration. Each unit includes a combustion turbine generator rated at 218 MVA, a heat recovery steam generator (HRSG), and an ST generator (STG) rated at 80 MVA with a total nameplate generating capacity of 232 MW. (There are variances with the Unit 5 and 6 nameplate capacities which indicate a generating capacity of 220 MW; Sargent & Lundy has not been able to confirm them.) PREPA originally awarded Abengoa, Sevilla, SA (Abengoa) an engineering, procurement, and construction (EPC) contract for the two units in 1997. In 2000, Abengoa withdrew from the contract, and Washington Group was appointed as the EPC contractor in 2004 to complete the combined-cycle installations. Units 5 and 6 were converted to fire natural gas in January 2020 and April 2020, respectively, and now are considered dual-fired units (i.e., they can fire 100% No. 2 fuel oil and 100% natural gas). As part of the dual-fuel conversion project, a selective catalytic reduction (SCR) will be installed on HRSG 5 in November 2020. Tetra Company performed an inspection of HRSG 5. HARPS D&E is planned to be replaced during the major inspection outage of the unit, which is expected to begin October 2021. Inspection of HRSG 6 is pending.

Units 5–10 are each connected to the PREPA transmission and distribution system through a dedicated transformer to the 115-kV switchyard. All units connect to the switchyard via underground cable, except for Unit 5, which is connected via overhead conductor.

There is also a gas-insulated substation (GIS) building on the plant premises; however, construction and installation has not been completed. Sargent & Lundy recommends removing the existing 115-kV GIS equipment and replacing it with new, modern GIS equipment that improve safety, reduce maintenance requirements, and ease for expansion of future services. Modifications to the existing GIS building may be needed to accommodate the installation of the new 115-kV GIS equipment. This project is currently ongoing and is expected to begin construction in by the end of 2021.

EQUIPMENT CONDITION

Major equipment (including the boilers, turbines, and generators) for San Juan's Units 7–10 are nearing the end of their design life. Units 7 and 8 are in limited operation, Unit 9 is out of service, and Unit 10 is not expected to return to operation. Anticipated infrastructure maintenance and repair would not be cost effective for continued service, largely due to the current extended disuse of some of the thermal equipment, extensive coastal corrosion impact across the plant and equipment, and safety concerns associated with the end-of-life operation. PREPA indicated that a painting program for corrosion prevention was initiated, but the details of this program were not available for review.

The combined-cycle units (Units 5 and 6) are relatively new and can fire No. 2 fuel oil and natural gas. With proper maintenance and extra care, they should last their intended design life, which is another 20 years for equipment typical of the service; however, diligence with routine and preventative maintenance, including an effective corrosion control program, will be required to continue operation through the intended design life. Resolution of the two ST deratings must be completed so that losses of 15 MW per unit—along with a decrease in thermal efficiency—can be regained. This long-term issue has not been completely identified, and it is likely there are multiple items contributing to the derating. Damaged bypass valve seats (both high-pressure [HP] and hot reheat bypasses) have been identified as a potential source and are currently in the process of being corrected.

The site has attractive features and valuable potential for repowering projects. Due to its close proximity to the high electrical demand of the San Juan metropolitan area and the Plant's existing infrastructure and interconnection points, Units 7–10 can be replaced with newer, cleaner, and more efficient generation options. A feasibility study for repowering the facility is recommended to fully assess the potential of this site with respect to the recommendations of PREPA's 2019 integrated resource plan (IRP) so that an optimal solution may be developed.

The existing GIS building sustained minor damage during Hurricane Maria and is suitable to house the existing 38-kV GIS equipment and the installation of new 115-kV GIS equipment. Installation of the new 115-kV GIS equipment will require some modifications of the building, such as new floor openings, to allow cable entrance to the equipment and may require localized floor reinforcement.

Future generation plans may require the installation of a new GIS building. The existing building lacks sufficient space to accommodate the additional future GIS breakers. The existing building cannot be expanded due to space constraints both for the building and transmission and generation connections. This project is currently ongoing and is expected to begin construction by the end of 2021.

Finally, there is currently an underground sea cable, 115-kV Line 38000, that is part of a planned San Juan underground loop. The loop will connect seven stations around the San Juan area. This underground sea cable was damaged by a contractor dredging in the channel. PREPA is assessing the damage and scope for repair. The underground loop requires both Line 38000 and the San Juan 115-kV GIS to be energized to take full advantage of the loop.

INFRASTRUCTURE AND INTERCONNECTIONS

The site building infrastructure is dated but serviceable. The steam plant administration building has older offices with ample room for multiuse purposes. The building also interfaces with the Plant and provides easy access to the turbine deck and control room of the current facility. The location of the admin building is central to the Plant and, due to the space's size and shape, can be repurposed without impacting the ability to install new equipment.

The warehouses and mechanical shops are valuable support for both San Juan and PREPA's fleet of generation sites; they also provide support to the transmission and distribution system. The workshops are well maintained, extensive, and important to PREPA since they provide the means for basic and complex maintenance and repair support from a local facility dedicated to PREPA. Work that can be completed on the island rather than mainland United States provides a distinct advantage in response time. As improvements are made across PREPA's generation fleet, consideration may be made to expanding and improving the shops' capability (e.g., machine tools, equipment, and staff training) to self-perform basic maintenance work for newer generation technologies.

The Plant has several interconnections with services outside the Plant boundary. The site receives both HFO and No. 2 fuel oil from two separate pipelines entering in at the east side and terminating near the main entrance at the street. PREPA purchases HFO through a supply contract with Freepoint Commodities LLC. A fifth amendment to the contract is expected to be signed, providing service through October 31, 2021. No. 2 fuel oil is provided through a contract with Puma Energy Caribe, LLC. An extension to the contract is currently being negotiated through November 20, 2021.

PREPA executed a contract with New Fortress Energy to provide offshore storage of liquefied natural gas and land-based regasification facilities so that natural gas can be delivered to fuel San Juan. The fuel contract now allows the combined-cycle Units 5 and 6 to fire 100% natural gas, but it's unclear how much gas capacity is available for others.

Municipal water and a sewer are also provided. Seawater is used as circulating cooling water. The intake and discharge of the circulating cooling water system are centered at the north side of the Plant.

OPERATIONS & MAINTENANCE

The Plant is composed of four departments: Operations, Conservation, Administrative, and the General Mechanical Shop. The Operations Department works on three shifts, staffing the Plant 24 hours a day. As of January 2018, there were 163 total personnel working at the site. The operable units generate power as directed by PREPA dispatch.

The units have regular outages every 12–18 months for maintenance and environmental reasons, per an EPA consent decree and PREPA direction. There is a service agreement with manufacturers for the gas turbines. The plant has extensive workshop capability and is mostly self-reliant for repairs of other equipment. Rebuilds of motors, generators, and rotors are by specialty shops.

Units 5 and 6 currently have a long-term service agreement (LTSA) with Mitsubishi Hitachi Power Service (MHPS) for the gas turbines (GTs), which is expected to expire no later than 2031 based on the contract execution date. Actual operating hours based on future use should not exceed the maximums; however, contract termination prior to the sunset date—based on the operating hours exceeding the contract—will need to be confirmed with the original equipment manufacturer (OEM) and reassessed after several more years of operation.

PERFORMANCE BENCHMARK

A decline in performance and reliability should be expected during the operating life of a thermal power generation plant, and this decline is evident in the case of San Juan. The Plant's thermal generation units (Units 7–10) have provided power generation service since the 1960s but are now at the end of their design life. The data is consistent with aging oil-fired units and has become more evident as the thermal units are cycled rather than base-loaded per the original design intent. Units 5 and 6, the combined-cycle units, have primarily been base-loaded since the major planned outages of 2014 and 2015. This operational change is reflected in the capacity factors and availabilities across the Plant. As the availability in Units 5 and 6 increased, the usage of the older Units 7 through 10 decreased accordingly.

The availability factor continued to be low throughout the past five years for the oil-fired units, and it is indicative of older plants that have maintenance and reliability issues. The heat rates provided for the thermal units are in the range for units of similar design and fuel type; however, there are inconsistencies between the operational data provided for independent engineering report and the data shown in the monthly report. Sargent & Lundy recommends PREPA review the data provided with the monthly reports and verify that the data is the same. Inconsistencies include heat rate, net MWh, and capacity factors. Plant performance testing could be performed to reestablish the facility's current capability.

FINANCIAL REVIEW

Sargent & Lundy compiled the historical O&M and capital expenditures (CAPEX) for San Juan from reported PREPA data and fiscal plan forecasts, comparing these values with O&M and CAPEX for existing units in operation in North America of similar configurations and operating profiles. Based on the data, Sargent & Lundy concludes that the San Juan costs are within the typical range of costs for similar units considering that higher expenditures are required for plants firing fuel oil as compared to natural gas.

ENVIRONMENTAL AND REGULATORY

Sargent & Lundy performed a limited environmental review of publicly available information and information provided by PREPA to evaluate the compliance status for San Juan. There were no compliance-related issues that would prevent renewal of the existing permits or impact near-term operation of the facility; however, the items below were identified as having unknown or potential compliance implications for San Juan:

- Air Emissions
    - Unit 9 particulate matter (PM) emissions exceed applicable mercury and air toxics standards (MATS).

  - The San Juan area is currently designated nonattainment for the one-hour SO_2 NAAQS.[1] The EPA/EQB[2] forthcoming plan for bringing the area into attainment with the one-hour SO_2 NAAQS may require SO_2 reductions from San Juan.
- Water and Wastewater
  - The ECHO[3] database and discharge monitoring reports (DMRs) show ongoing discharge exceedances (Sargent & Lundy was not provided DMRs for December 2018 and thereafter for review).

RECOMMENDATIONS AND CONCLUSIONS

The Plant's total nameplate capacity is 864 MW; however, the current operating capacity is approximately 534 MW, of which 30 MW should easily be recoverable after the combined-cycle STG deratings are resolved. A decline in performance and reliability should be expected during the operating life of a power generation plant and is evident in the case of the San Juan thermal units. Units 7–10 have provided power generation service since the 1960s but are at the end of their design life. It is recommended that the San Juan's thermal units be phased out of service and replaced by units with the capacity and flexibility as determined by a separate load demand and resource study. PREPA intends to retire the steam units over the next five years.

Sargent & Lundy found Units 7–10 to be in a partially operable condition despite the age, extended layup, and prevalent signs of degradation across the units and auxiliary equipment. The open-frame plant design exposes much of the equipment to coastal conditions, and the Plant's poor condition is primarily the result of this design. The facility is a 1960s oil-fired design and does not have the benefit of modern emissions controls or equipment.

Since its initial siting, San Juan is—due to its proximity to the large San Juan population, the availability of seawater supply for cooling, and the nearby port services—an ideal location for power generation on the island. If new generation is contemplated, a modern design should be considered, one that uses best available technologies for improved efficiency, environmental impact, and emissions controls. The new generation units can have additional operational flexibility designed for rapid response to support shifting load demands and a greater penetration of renewable sources of power like wind and solar. Any new design or modification must include better protection and material selection than currently in place for this coastal installation, as well as hardening of the facilities to enable command and control of power production during emergency conditions, such as harsh weather events.

[1] National Ambient Air Quality Standards
[2] Puerto Rico Environmental Quality Board
[3] Enforcement and Compliance History Online (EPA)

Sargent & Lundy noted 15-MW deratings on each of the combined-cycle STGs and recommends addressing the deratings to regain this loss in power output and efficiency. Resolution of the deratings is required for the units to operate at full capacity. Sargent & Lundy recommends that an independent third party conduct a full root-cause analysis and provide recommendations and an action plan to bring closure to the issue. PREPA is tracking the work associated with the steam turbine and steam side efficiency issues to address long-term issues with equipment and infrastructure at San Juan and other facilities. Once corrected, there should be no issue with the combined-cycle facility reaching its full electrical output and its design heat rate.

Care must be taken to ensure that replacements or upgrades to the Plant are suitable for an aggressive, salt-laden marine environment exposed to coastal winds. Typically, competitively priced OEM standards for power generation and balance-of-plant equipment are not well suited for this type of operating environment. New equipment must be configured for the challenging conditions at San Juan. Failure to make allowances for suitable materials, equipment selection, buildings/enclosures, and other aspects of the facility design to protect the Plant from its operating environment will result in excessive future O&M costs and a shorter plant design life for any new installation. Suitable design specifications appropriate for this operating environment include corrosion-resistant material specifications, appropriate welding selections—including special treatment of all metal seams, stitched connections, and fastenings with sealants, gaskets, and coatings—use of protective equipment enclosures, proper system selections, and marine coatings systems. Due to these requirements, coastal power generation sites are inherently more expensive than those installed in less aggressive operating environments.

PREPA continues to evaluate the need for additional grid support and generation throughout the island. Smaller, rapid-start GT equipment can be easily adapted to integrate purge credit, battery storage for instantaneous response, and other similar features to provide a quicker response for a future grid that is planned to integrate a larger amount of renewable power. Generators from Units 7–10 may be evaluated for use as in synchronous condensing operations. Given the age of the Plant, Sargent & Lundy anticipates that only the generators may be suitable and that all balance-of-plant equipment would require replacement to ensure reliable service.

Ongoing proposals for Plant replacements, upgrades, and new generation at San Juan should consider the guidelines provided herein. New operating regimes and other comparisons must be made so that equipment is selected to suit the future direction of the power generation and distribution system planned for Puerto Rico.

1. INTRODUCTION

The Puerto Rico Electric Power Authority (PREPA) is responsible for generating, transmitting, and distributing electricity for the island of Puerto Rico. PREPA engaged Sargent & Lundy to perform an independent technical review of the San Juan Power Plant ("San Juan" or "Plant").

1.1. PLANT DESCRIPTION

San Juan is located on the northern coast of Puerto Rico in San Juan. It consists of four thermal steam units and two combined-cycle units with a total nameplate capacity of 864 MW. San Juan has been a major generator in the PREPA fleet and continues to serve on a limited basis as power distribution challenges face the island.

Figure 1-1 — San Juan Power Plant Geographic Location

Source: Google Earth

San Juan consists of four conventional units fired by heavy fuel oil (HFO)—Units 7, 8, 9, and 10—each consisting of a Combustion Engineering (now GE Power) fired natural circulation boiler, a General Electric condensing steam turbine (ST) generator, and auxiliary equipment. All four generators are rated for 133,689 kVA; each unit is rated for 100 MW. The power station was conceived in the early 1950s, with the first unit,

Unit 7, going into commercial service in 1965 and the last unit, Unit 10, beginning commercial service in 1969.

The combined-cycle blocks of the Plant are among PREPA's newest, beginning commercial operation in October 2008. They are two units—Units 5 and 6—each in a 1x1 configuration. Each unit includes a combustion turbine generator rated at 218 MVA, a heat recovery steam generator (HRSG), and a ST generator (STG) rated at 80 MVA with a total generating capacity of 232 MW. PREPA originally awarded Abengoa, Sevilla, SA (Abengoa) an engineering, procurement, and construction (EPC) contract for the two units in 1997. In 2000, Abengoa withdrew from the contract and Washington Group was appointed as the EPC contractor in 2004 to complete the project. Units 5 and 6 were converted to fire natural gas in January 2020 and April 2020, respectively, and now are considered dual-fired units (i.e., the units can fire 100% No. 2 fuel oil and 100% natural gas). As part of the dual-fuel conversion project, a selective catalytic reduction (SCR) will be installed on HRSG 5 in November 2020. Tetra Company inspected HRSG 5. HARPS D&E will be replaced during the major inspection outage of the unit, which will begin in October 2021. Inspection of HRSG 6 is pending.

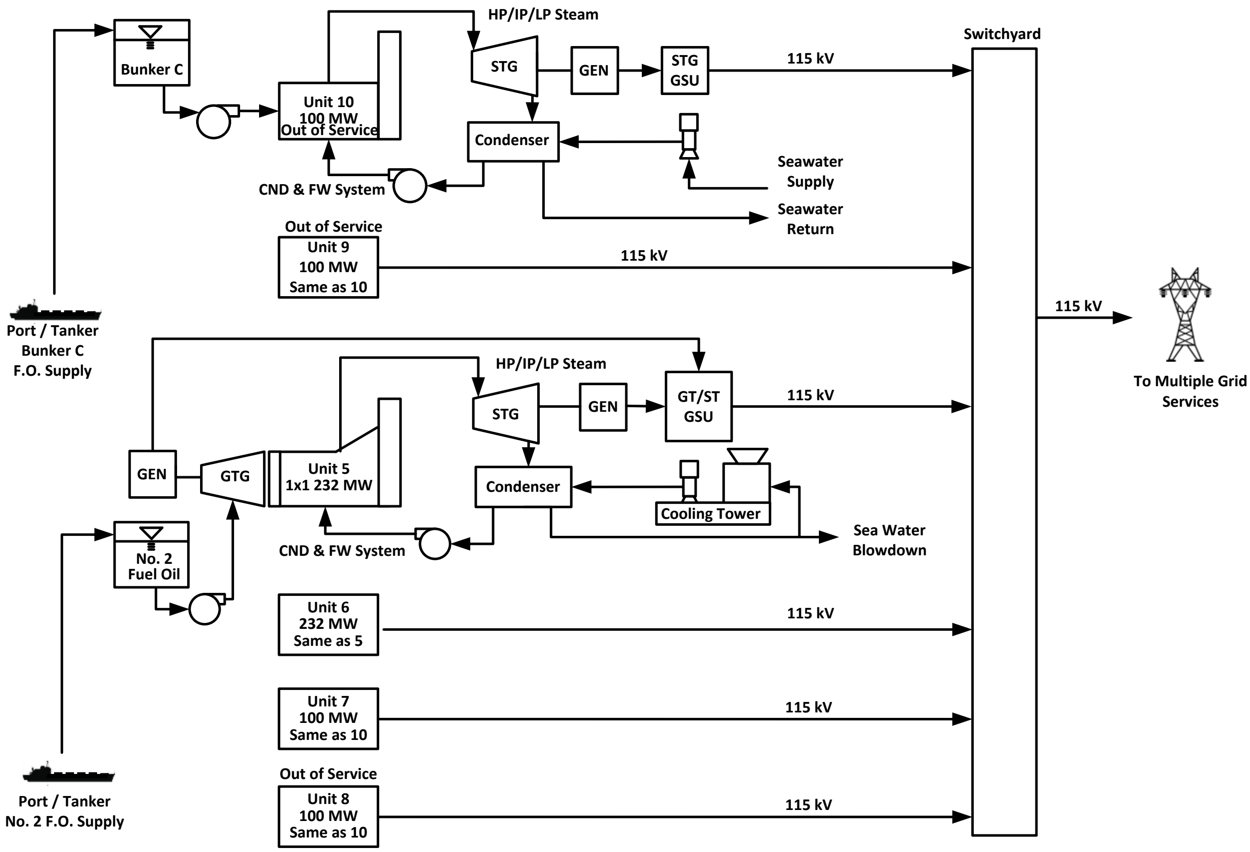
The two W501F gas turbines (GTs) with mechanical and electrical modules and two Ansaldo condensing STs and associated valves were purchased under the Abengoa contract. The W501F GTs were developed in a joint venture between Westinghouse and Mitsubishi Heavy Industries. The machines purchased by Abengoa were an earlier Westinghouse version. Shortly after initial procurement of the San Juan GTs in 1997, Siemens acquired the Westinghouse product line (mid-1998).

HFO and No. 2 oil are delivered to the Plant via transfer lines from a docking station at Puerto Nuevo. An interconnection facility was built to deliver natural gas to the Plant from the MFH facility. Water is provided via the PRASA[4] connection onsite near the carpenter shop on the main road access. Units 5–10 are each connected to the PREPA transmission and distribution system through a dedicated transformer to the 115-kV switchyard.

An overview schematic representation of the San Juan facilities is provided in Figure 1-2.

[4] Puerto Rico Aqueduct and Sewer Authority

Figure 1-2 — San Juan Overall Plant Configuration



1.2. SCOPE OF REVIEW

This technical report includes an assessment of the Plant design, operations and maintenance (O&M) activities, plant organization and personnel, technical performance, commercial arrangements and obligations, and provisions for environmental permitting. Sargent & Lundy's objective is to provide an overview of the condition of the asset, assess whether the facility has been operated and maintained in accordance with generally accepted industry practices, and identify significant challenges to continued successful operation. Recommendations for demolition, equipment upgrades, or operational improvements are also included. Additionally, Sargent & Lundy performed the Phase I Environmental Site Assessment (Phase I ESA) in May 2019 with the site visit in December 2018. Please see report SL 014468.SJ.ESA [1] for Sargent & Lundy's findings of the Phase I ESA.

Sargent & Lundy acquired information to conduct its review:

- Documentation provided by PREPA's corporate operations and plant personnel

- Discussions with Plant personnel on the phone and during several site visits to the facility from 2018 to 2020
- Industry data obtained from market research databases and publicly available sources to evaluate plant characteristics

Sargent & Lundy understands that this review is connected to the request for proposals (RFP) to manage, operate, maintain, and decommission, as applicable, one or more of the base-load generation plants and gas turbine peaking plants located throughout Puerto Rico, including San Juan.

2. TECHNICAL DESCRIPTION

The characteristics of the generating units at San Juan are shown in Table 2-1. Noting that Sargent & Lundy's visits indicated that several units are classified as "Non-Operational," the aforementioned total breakdown of system capacity likely requires a reduction to reflect the as-found conditions. From the table below, 564 MW can be classified as operational; however, the STs at Units 5 and 6 are currently de-rated by 15 MW per unit, so 534 MW is currently available for dispatch.

Table 2-1 — Production Plant Overview

Unit Name	COD	Technology	Fuel	Nameplate Capacity (MW)	Status (As of October 2020)
San Juan Combined-Cycle Gas Turbine #5	2008	Combined-Cycle Gas Turbine	No. 2 / Natural Gas	168*	Operational but de-rated by 15 MW
San Juan Combined-Cycle Steam Turbine #5	2008	Steam	—	64*	Operational but de-rated by 15 MW
San Juan Combined-Cycle Gas Turbine #6	2008	Combined-Cycle Gas Turbine	No. 2 / Natural Gas	168*	Operational
San Juan Combined-Cycle Steam Turbine #6	2008	Steam	—	64*	Operational
San Juan Steam Turbine #7	1965	Steam	HFO	100	Non-Operational (forced outage due to condenser pump issues, return date unknown at this time)
San Juan Steam Turbine #8	1966	Steam	HFO	100	Operational but de-rated to 40 MW; available for emergency use only, due to MATS operating limits (33 days remaining until April 2021)
San Juan Steam Turbine #9	1967	Steam	HFO	100	Operational but de-rated to 90 MW due a boiler leak issue
San Juan Steam Turbine #10	1968	Steam	HFO	100	Non-Operational (long-term outage)

1. **Operational**—Functioning and suitable for power generation
2. **Non-Operational**—Out of service temporarily and not generating power
* There are variances with the Unit 5 and 6 nameplate capacities which indicate a generating capacity of 220 MW (GT 160 MW and ST 60 MW); Sargent & Lundy has not been able to confirm these values.

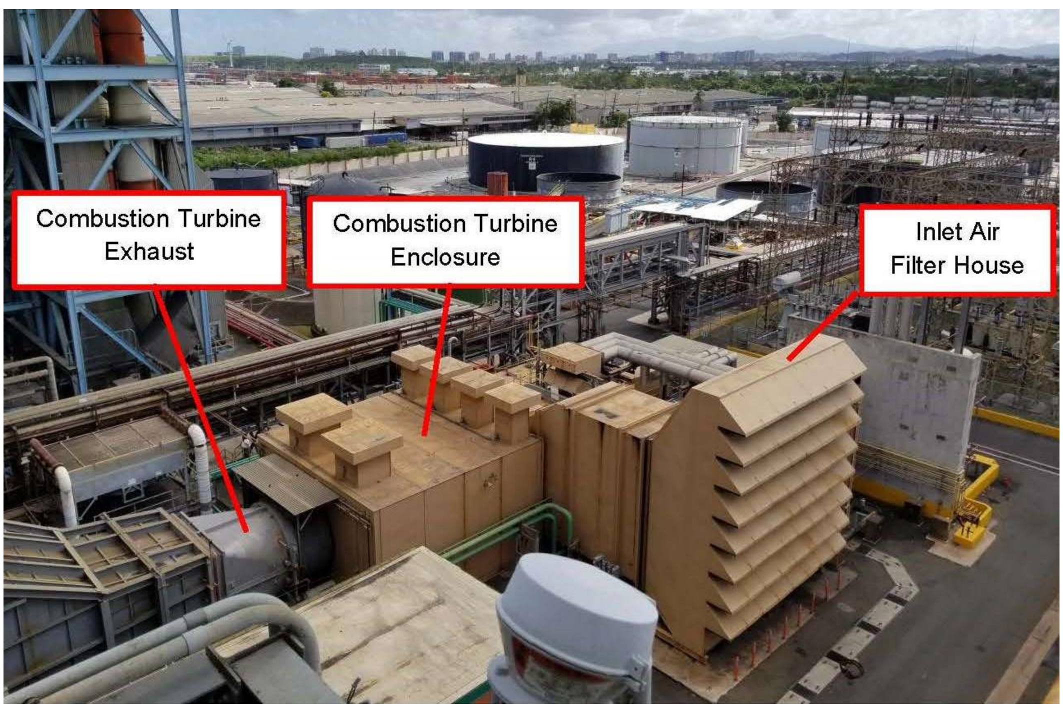
2.1. MECHANICAL SYSTEMS

The current unit numbering system was based on the original facility layout. The original plants (Units 1–6) were constructed using an ST building along the Port Authority on San Juan Harbor. These thermal units were installed in the 1950s and were a nominal 22 MW each. Units 7 and 8 were constructed to the east of the original power block ,and Units 9 and 10 were constructed to the west when installed in the 1960s. When the original Units 1–6 were retired, the current Units 5 and 6 were built in the middle on the site of the original units. Unit 5 and 6 used the original ST bay with new condensers inserted and fitted below the turbine deck.

2.1.1. Gas Turbines

San Juan Units 5 and 6 are two separate combined-cycle blocks (2x[1x1x1]) using Westinghouse W501FC GTs in a multiple-shaft configuration of one GT, one heat recovery steam generator HRSG, and one ST. Both GTs (Unit 5 – S/N 38 A8013; Unit 6 – S/N 38 A8018) are of the same design and rated for a nominal 168 MW. Both are located outdoors with weather enclosures. These GTs include a 16-stage high-efficiency axial flow compressor with variable inlet guide vanes. The combustion system features advance cooling and multi-fuel capability with 16 individual combustors. The four-stage turbine section incorporates advance cooling design characteristics and thermal bearer coatings. The inlet air filters are two-stage static with pre- and post-filtration. Although inlet air cooling equipment is typical for this locale, San Juan does not have it. Currently, these units now can fire natural gas and No. 2 fuel oil with steam injection for nitrogen oxide (NOx) control.

Figure 2-1 — San Juan Gas Turbine Unit 6



Source: Siemens promotional literature

The Unit 5 commercial operating date was October 21, 2008, and the Unit 6 commercial operating date was September 28, 2008.

2.1.2. Steam Turbines

2.1.2.1. Units 5 and 6

The STs associated with the San Juan combined cycles were manufactured by Ansaldo Energia S.P.A. Both STs are located indoors using an existing turbine hall location and infrastructure from the original Plant design. Both STs are of the same design and rated for 67 MW with high-pressure (HP) steam conditions of approximately 1,436 psia and 990°F and a hot reheat steam temperature of 990°F.

Each ST includes two steam extraction points for feedwater heating. This increases condensate temperature to the HRSG, which increases exhaust-gas stack exit temperature to mitigate the potential for acid dew point corrosion. Deaeration is provided with an external stand-alone deaerator. Pegging steam to the deaerator is from auxiliary steam. The nameplate of Unit 6 is shown in Figure 2-2 and is typical of both units. A sectional view of the Unit 5 and 6 steam turbines is shown in Figure 2-3.

Figure 2-2 — San Juan Unit 6 Steam Turbine Nameplate (S/N 2175)

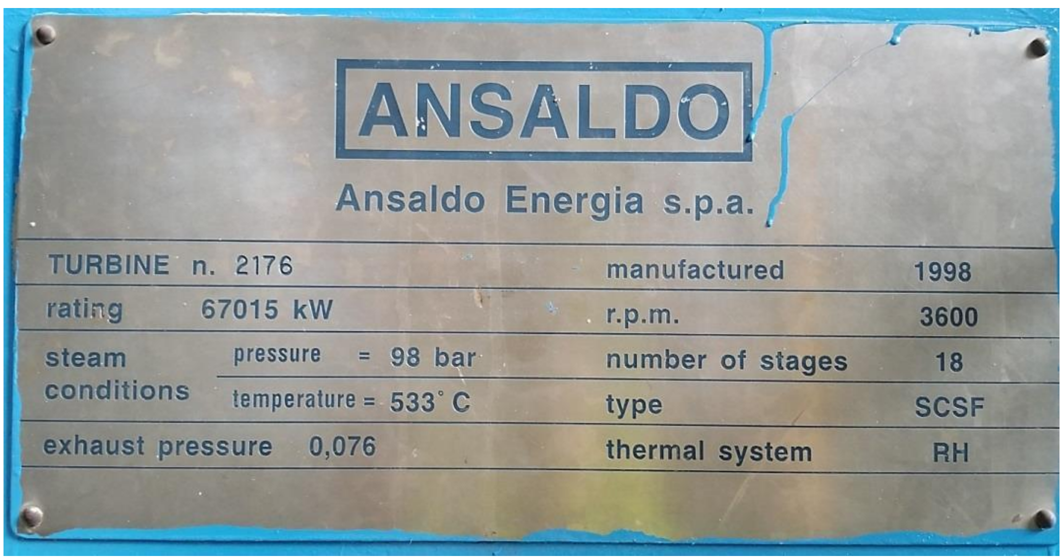
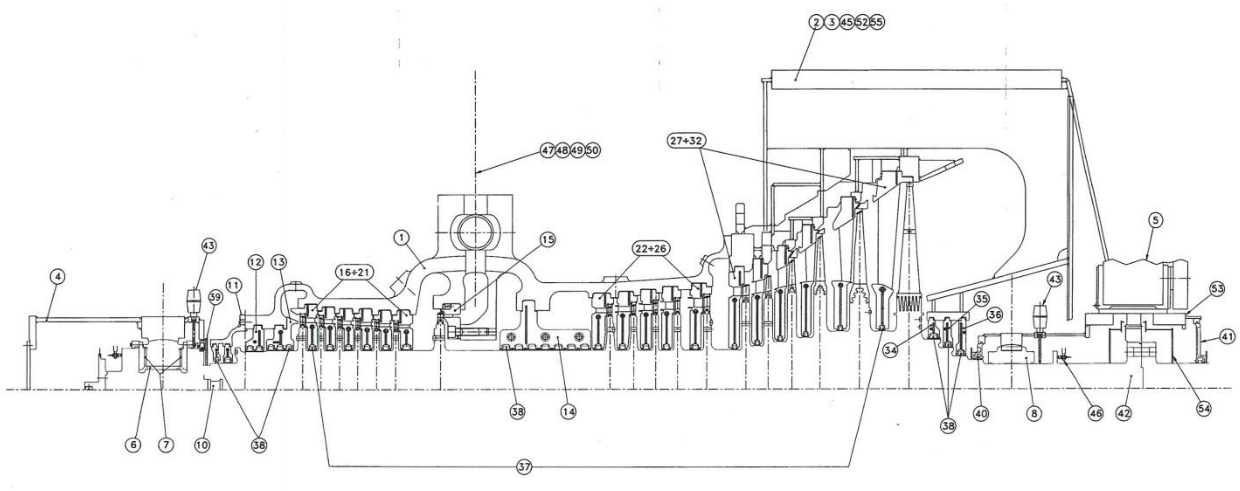


Figure 2-3 — San Juan Units 5 and 6 Steam Turbine Sectional View



2.1.2.2. Units 7–10

The STs associated with the San Juan thermal units (Units 7–10) were manufactured by General Electric. All STs are located outdoors with weather enclosures. All STs are of the same design and rated for 100 MW with HP steam conditions of approximately 1,814.7 psia and 1,000°F and a reheat steam temperature of 1,000°F. The name plate of Unit 7 is shown in Figure 2-4, which is typical for Units 7–10. A sectional view of the steam turbines is shown in Figure 2-5.

Figure 2-4 — San Juan Unit 7 Steam Turbine Nameplate (S/N 164027)

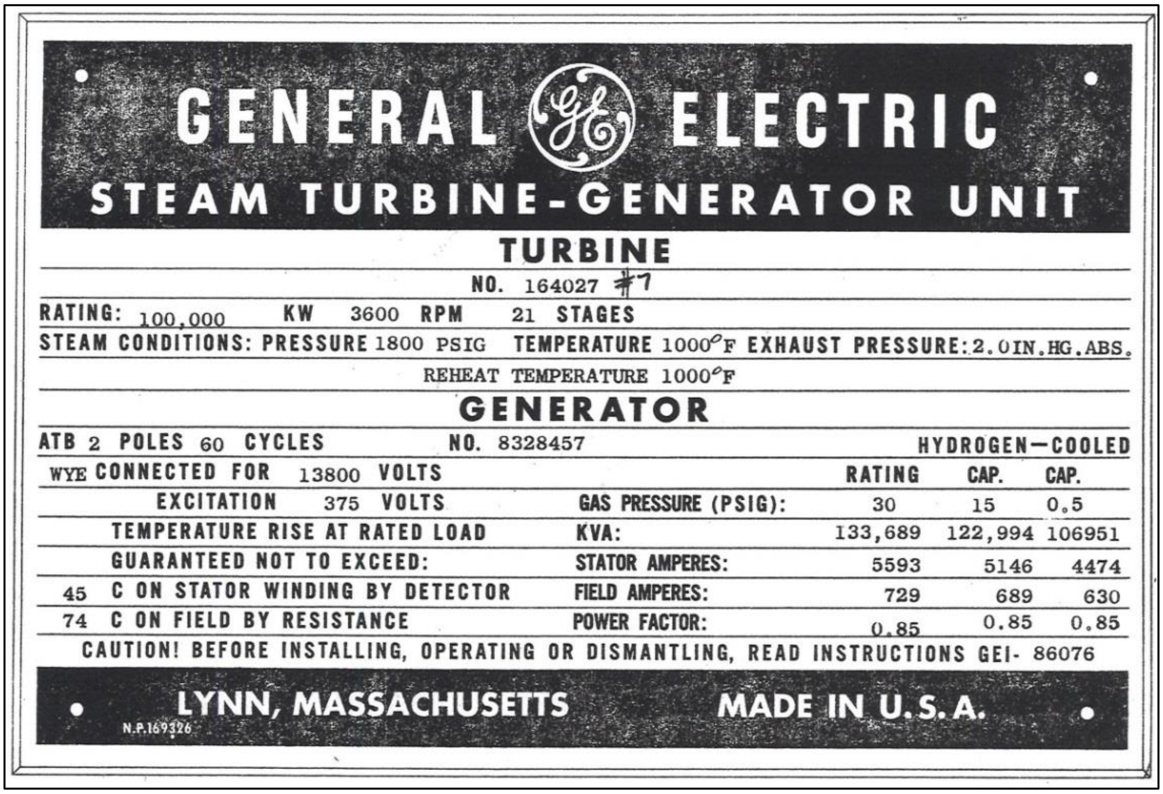
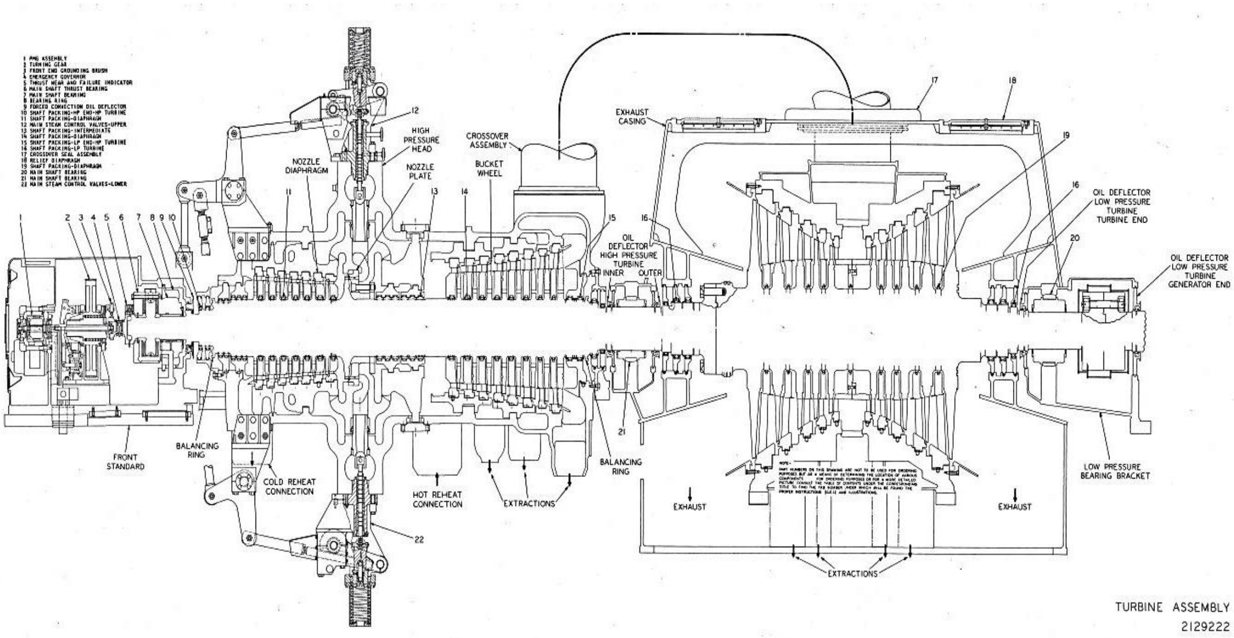


Figure 2-5 — San Juan Units 7–10 Steam Turbine Sectional View



2.1.3. Boilers and Heat Recovery Steam Generators

2.1.3.1. Units 5 and 6

The Unit 5 and Unit 6 combined-cycle steam systems have the same design. Steam is generated in the HRSG by the hot exhaust gases from the GTs. It is then piped to the ST for conversion into electrical energy. Each HRSG delivers steam at two pressure levels: HP and intermediate pressure (IP). The ST uses three pressure levels of steam: HP, IP, and low pressure (LP). The LP steam is exhausted from the IP section of the turbine and is not generated by the HRSG.

The HRSG HP and IP heat exchangers use finned seamless tubes to transfer the heat from the hot exhaust of the GT to the water and steam. The first heat exchanger—the economizer—preheats the feedwater for entry into the evaporator section heat exchangers where it is turned to saturated steam. The evaporators send the steam to the next series of heat exchangers—the superheaters—making it superheated and of sufficient quality for use in the ST. Cold reheat steam is returned to the HRSG from the ST where it is combined with IP steam and reheated in the IP reheaters before being sent to the ST. The superheaters and reheaters are located in the front end of the HRSG, closer to the hottest entry point of the combustion gases and using the highest temperatures available for heat addition and steam delivery.

Steam from the HRSG is piped to the ST as HP steam via the respective main steam stop valve. After converting to rotating energy in the ST, the HP steam exits the turbine and enters the return pipe, called the cold reheat system, to the HRSG. The returned steam is combined with IP steam from the HRSG, reheated, and sent back to the ST as IP steam for use in the IP section of the turbine. It then discharges to the LP turbine before exhausting to the condenser for heat rejection. Isolation, stop, and control valves are provided on each motive steam pipe.

The HRSG attemperates steam with feedwater to control the HRSG outlet steam temperatures. Feedwater is injected by the attemperator nozzles to obtain the required outlet temperature. Additional attemperation is used in the bypass valves where the steam pressure and temperature are let down to match the receiving system's parameters.

2.1.3.2. Units 7–10

Units 7 and 8 are tangentially fired Combustion Engineering (now GE Power) HFO-fired boilers with reheat and a turbine nameplate capacity of 100 MW each. The units are rated at 2,175 psia, 1,005°F, at 787,000 lbs./hr. Unit 7 began commercial operation on December 23, 1965, and Unit 8 began commercial operation on July 15, 1966.

Units 9 and 10 are tangentially fired Combustion Engineering (now GE Power) HFO-fired boilers with reheat and a turbine nameplate capacity of 100 MW each. The units are rated at 2,035 psia, 1,000°F, at 787,000 lbs./hr. Additional details about the boilers and turbines were not provided for review. Units 9 and 10 began commercial operation on November 9, 1967 and June 7, 1968, respectively.

Units 7–10 use similar overall designs. The similar slide-along design aids in uniform equipment layout for access and location. The units are arranged West to East: Units 10 and 9, Units 5 and 6, and Units 7 and 8. The thermal units are double stacks, each with the HRSG stacks from Units 5 and 6 enclosed in a common outer stack. The thermal units are fired with HFO through tilting burners.

Boiler-specific equipment includes forced draft fans with windboxes (East and West), induced-draft fans, recirculation fans, air heaters, and a deaerator.

2.1.4. Steam Systems

2.1.4.1. Units 5 and 6

Steam is piped to the ST, entering through the control valves and into the steam chest for distribution to the turbine nozzles and blade assemblies.

HP and IP steam bypass systems are provided to allow for startup, shutdown, and ST trip operations. The bypasses operate when the ST is not available or when the ST is being bypassed, such as during warmup or shutdown periods. The bypass also helps for a controlled transition to and from ST operations. The HP steam is bypassed to the cold reheat system. The IP steam is bypassed into the condenser.

Steam is extracted from the turbine at key locations for energy recovery. The extraction points are provided with actuated and non-return valves as required for turbine-water induction protection. The extractions provide heating to the feedwater heaters and are provided with pressure and temperature monitoring for the preheater performance. Automatic drains with actuated valves are provided for condensate removal from steam lines and preheaters.

The auxiliary steam system provides steam for pegging and heating for the deaerator. It is also a source of gland steam for the ST seals during startup and shutdown scenarios. Normally, auxiliary steam is provided from an attemperated takeoff from the cold reheat steam. During initial startup, steam can be taken from an auxiliary steam header interconnected with the other thermal units at San Juan.

During normal operation (25% load and above), the ST is self-sealing, and the gland sealing steam is provided from an HP stage leak-off. Auxiliary steam is only required for loads under 25%.

2.1.4.2. Units 7–10

For Units 7 through 10, steam is provided to the ST as HP and as IP. The HP steam pipe exits the boiler from the superheater, and the flow is divided into two feeds with stop valves at the turbine prior to the connection to the steam chest and nozzle block. The IP system is also split into two flows prior to admittance to the intercept and stop valves and IP turbine. The IP turbine discharges to the LP turbine, and the flow path is divided through opposing rotors.

No turbine bypass dump system to the condenser is provided for cycling or aid in startup, and the unit is brought up using the atmospheric vents on the boiler side.

The turbine is down exhaust, resulting in a high turbine deck with the condenser mounted below it. Condensate is pumped from the condenser via pump, discharging to the deaerator.

2.1.5. Feedwater and Condensate Cycle

2.1.5.1. Units 5 and 6

The main function of the boiler feedwater system is to deliver deaerated feedwater to the HRSG HP and IP systems, first to the economizers, then to the evaporators, and then the superheaters as steam. The feedwater system also supplies water to the various attemperators, including the HP, IP, and auxiliary steam systems. The feedwater source for the boiler feedwater pump suction is the deaerator tank, which is supplied from the condensate system.

The Ansaldo units both have separate sets of boiler feed pumps for the HP and IP supply. The pumps are 2x100% for each system, totaling four pumps per unit, with the pumps that are off providing automatic backup as standby units. Each pump takes suction from the deaerator tank and delivers to the HP and IP drums, respectively, through the corresponding economizers. The economizers preheat the water to near saturation temperatures before delivering it to the drums and then to the evaporators for conversion into steam. The drum level control valves modulate the feedwater flow as required to maintain a proper drum level.

The drum level is controlled by parallel control valves with separate high and low flow ranges for more accurate control over large ranges of loads for load response and cycling dispatch advantages. The low flow range is used during fill, startup, and operation through low load ranges.

The Termomecanica pumps have the following ratings:

- **HP feedwater pumps**: 1,217 gallons per minute (gpm), 4,389 ft total developed head, and 1,831 psig[5] discharge pressure with a 1,750-horsepower (hp) motor.
- **IP feedwater pump**: 176 gpm, 1,386 ft total developed head, and 614 psig discharge pressure with a 125-hp motor.

The pumps are protected with a low suction-pressure trip and from low flow by recirculation control valves discharging back to the deaerator.

The Unit 5 and 6 condensate system recovers steam from the ST exhaust, turbine bypasses, and steam drains, condenses it, and recovers it for reuse in the Rankine cycle. The system has two full-capacity vertical condensate pumps taking suction from the hotwell of the condenser and discharging it to the deaerator through two extraction steam heated feedwater preheaters. Makeup water and initial fill to the system is provided by the demineralized water system through a vacuum deaerator. The demineralized water is supplied from the demineralized water tank, and excess water is returned to the tank.

The condenser is single-shell two-pass with a divided water box. Steam enters at the top of the condenser from the downward exhaust ST. The turbines are mounted in the old Unit 1–6 turbine generator house on the turbine deck with the condenser mounted below it. The condenser was fit into the existing turbine building. The condenser uses circulating water from the San Juan Harbor as the cooling water in a once-through configuration. The condenser is monitored for leaks with multiple conductivity probes in the hotwell.

The condenser uses titanium tubes and tube sheets. Air extraction is provided by 2x100% vacuum pumps located on the turbine deck. A ball cleaning system is used to keep the tubes clear of biofouling and small debris that is not strained by the intake screens.

The condensate pumps are rated for 1,374 gpm at 527 ft of total developed head with a 250 hp motor. The pumps are 2x100%, with one pump operating and the other used as the automatic standby. The pumps and gland steam condenser are protected from low flow by recirculation control valves.

2.1.5.2. Units 7–10

The four thermal units (Units 7–10) are described together herein, as the design is similar.

The turbine is down exhaust, resulting in a high turbine deck and the condenser mounted below it. Condensate is pumped from the condenser via 2x100% pumps, discharging to the deaerator through three

[5] Pounds per square inch, gage

LP feedwater heaters. Four extractions from the LP turbine are directed to the first two LP feedwater heaters, Heaters 1 and 2. Three extractions from the IP turbine go to the third LP heater (Heater 3), the deaerator (Heater 4), and the first HP heater (Heater 5). An extraction from the final stage of the HP turbine, which coincides with the cold reheat line, enters Heater 6.

Two boiler feedwater pumps take suction from the deaerator for delivery to the steam drum through two HP feedwater heaters. From the observable nameplates at the site, Pacific boiler feed pumps are used. The boiler feedwater pumps are 2x50% and deliver to the boiler.

2.1.6. Circulating Water Systems

Circulating water is provided from the ocean for cooling water to the condensers in a once-through configuration. It is channeled to intakes, to the inlet screens, and to the pumps for discharge back to the ocean. The intakes for the units are split with Units 9 and 10, separate from Units 5 through 8.

2.1.6.1. Units 5 and 6

The east-side circulating water system consists of a bay side intake structure, screenwell chambers, four Beaudrey traveling intake screen assemblies, screen wash pumps, and one Westinghouse vertical pump for each unit with a shared spare pump for redundancy.

The Unit 7 and 8 pumps are mounted to the deck above the water intake basin. A service platform is provided at the motor level for servicing and inspection of the units. An overhead crane is available for maintenance removal and access.

The Unit 5 and 6 pumps are mounted to the deck below the ST in the turbine house. A service platform is provided at the motor level for servicing and unit inspection. An overhead crane (60-ton main hook, 15-ton auxiliary hook) is available for maintenance removal and access. Each unit has 2x100% Flowserve circulating water pumps sized at 50,000 gpm, 41 ft of head, and 700 hp. One pump is used for normal operation with the other pump in automatic standby. The pumps take suction from the common intake basin with Unit 7 and Unit 8.

The pumps discharge to the circulating water pipe, and the circulating water flow is split to either side of the condenser for heat rejection of the turbine. After cooling the condenser, the circulating water is piped to the circulating water discharge channel for release to the bay.

A bladder is currently used to separate the east-side from the west-side discharge channels.

2.1.6.2. Units 7–9

The west-side circulating water system consists of an oceanside intake structure, screenwell chambers, FMC Corporation traveling intake screens, screen wash pumps, and Westinghouse vertical pumps for each unit, with a spare that is shared for redundancy. The west-side intake is separated from the discharges by a jetty system.

The pumps are mounted to the concrete deck above the water intake basin. A service platform is provided at the motor level for servicing and unit inspection. An overhead crane is available for maintenance removal and access.

Separate seaweed and debris trenches are also provided for the clearance of debris from the traveling intake screens. The seaweed channels bypass the Plant and are directed into the discharge tunnel for release into the ocean.

2.1.7. Water Treatment System

Raw water for Plant use is provided by PRASA. The PRASA feed enters the facility east of the carpenter shop at the main entrance road. It feeds two main areas, the reverse osmosis (RO) trailer area and the new demineralizer plant for Units 5 and 6 near the admin building. Raw water is stored on site as feedwater for the demineralizer systems, cooling tower system makeup, and sanitary services. Sanitary waste is returned to the PRASA system and process water is treated, sent through oily water separators, and discharged through the circulating water outfalls.

The original demineralizer system was expanded with rental equipment, new equipment, and additional tanks during the addition of Units 5 and 6. The original equipment consisted of three cation exchangers (320 gpm each), a common decarbonator (960 gpm) with an integral clearwell, one blower and three transfer pumps, three anion exchangers (320 gpm each), and two mixed bed polishers (640 gpm each). The units are all cross tied. The newer demineralizer system by Anderson was added in 2007 and includes one cation exchanger (320 gpm), a common decarbonator (1,800 gpm) with an integral clearwell, one blower with a fourth transfer pump, one anion exchange (320 gpm), and one mixed bed polisher (640 gpm).

Construction for replacement of the rental units' water treatment system is currently in process. The CAPEX schedule continues the water treatment upgrades through 2020.

2.1.8. Units 5 and 6 Natural-Gas Conversion

Units 5 and 6 were converted to fire natural gas in January 2020 and April 2020, respectively, and now are considered dual-fired units (i.e., the units can fire 100% No. 2 fuel oil and 100% natural gas). As part of the dual-fuel conversion project, an SCR will be installed on HRSG 5 on November 2020. Tetra Company performed an inspection of HRSG 5. HARPS D&E will be replaced during the major inspection outage of the unit, which will begin in October 2021. An inspection of HRSG 6 is still pending.

2.1.9. Fuel Systems

Fuel storage and transfer systems on site include HFO (sometimes called Bunker C, or No. 6) and No. 2 oil for the thermal units and the GTs, respectively. No. 2 fuel oil can be received by barge or ship into two tanks that feed the GT units. The deliveries of both No. 2 and HFO are provided by separate pipelines from the Port of San Juan. An interconnection facility was built to deliver natural gas to the Plant from the MFH facility.

2.1.9.1. Natural-Gas System

Liquified natural gas is vaporized and delivered through a 10-in carbon steel pipeline to a metering station located near condensate Tanks 7–8. From the metering station, two 6-in carbon steel pipelines are supplied to Units 5 and 6. The natural-gas system is designed to operate at normal conditions of 525 psig and 48°F. Refer to the fuel sale and purchase agreement [3] for details.

2.1.9.2. Heavy-Fuel Oil Systems

The HFO system consists of four reserve tanks (only three are in service), four service tanks, pumps, heaters, and a pipeline connection to fuel fill from offsite. The offsite fuel unloading station is in the San Juan Harbor.

Installed in 1954, each of the four combined reserve tanks hold a nominal 41,000 barrels total. The four service tanks are a nominal 122,242-gallon (2,900-barrel) capacity each. Fuel is provided through transfer and delivery pumps and heaters to the respective thermal units for firing. Tank R-3 is out of service; however, it is anticipated, if needed, that it could be restored for use again with an engineering evaluation and corrective restoration of the over-pressurization damage.

2.1.9.3. No. 2 Fuel Oil Systems

The No. 2 fuel oil systems are dedicated to the GTs in Units 5 and 6. The two reserve tanks (R-5 and R-6) have a total capacity of 40,000 barrels (1,680,000 gallons) each. Piping, pumps, and valves are installed to enable either of the 40,000-barrel service tanks to supply No. 2 to either GT unit while simultaneously supplying fuel to Units 7–10 for startup.

Each GT fuel delivery system is served by three 50% capacity pumps. The pumps deliver from the service tanks to the fuel-oil skid at the respective GT. Each pump provides 50% of the required fuel delivered for full capacity operation of the unit. The pump not running is engaged as an automatic standby.

2.1.10. Fire Protection

The fire protection system is common for all units in the facility. The fire protection water tank and pump house are located at the northwest side of the Plant adjacent to the circulating water intake of Units 9 and 10. The system mainly consists of the tank, pumps, and piping network, including the underground loops and branches. The fire protection system ties into the main fire control panel located in the control room for monitoring by the operators.

The tank has a 420,000-gallon capacity and is dedicated to the system. There are two pumps, one electric and one No. 2 fuel oil, in a common one-room shelter; both are rated for 1,500 gpm at 107 psig.

The fire protection system provides protection to the main equipment at site. A few of the protected systems include the main and auxiliary transformers, fuel-oil heaters and tanks (foam-based), ST bearings, ST underfloor, and cooling towers of the closed cooling system.

Carbon dioxide systems are provided for original equipment manufacturer (OEM) equipment such as the Westinghouse GTs and Ansaldo ST mechanical packages. The OEM provides a dry chemical system for the GT exhaust bearing.

2.1.11. Compressed-Air System

The Unit 5 and 6 compressed-air system is contained in a building adjacent to Unit 5. The system is by Ingersoll Rand and consists of two separate systems: the instrument air system and the service air system. Both systems use screw-type compressors to provide oil-free and clean air to the respective main headers.

The instrument air system provides air to the air actuated valves, instrumentation, and control devices. Each instrument air compressor is rated for 500 standard cubic feet per minute, 125–150 psig discharge pressure, and 100ºF design temperature. Each air compressor is driven by a 125 hp, 460-voltage-alternating-current motor. The air compressors are water-cooled. A dual tower dryer and air receiver with an automatic drain are provided.

The service air system provides air for general use, including maintenance, cleaning, and shop tools. Each service air compressor is rated for 300 standard cubic feet per minute, 125 psig discharge pressure, and 100°F design temperature. Each air compressor is driven by a 75-hp, 460-voltage-alternating-current motor. The air compressors are water-cooled. A service air tank with an automatic drain is provided.

Air is supplied to various equipment and systems, including the following:

- Gas turbines
- HRSG units
- STG units
- Gas turbine fuel-handling system
- Demineralizer system
- Circulating-water system
- Component-cooling water system
- Condensate storage and transfer system
- Machine shop

The Unit 7–10 compressed air system is adjacent to each respective unit in the auxiliary building and headered together for each block. The system is a mixture of different units and contains Atlas Copco and Sullair units, dryers, and air receivers for the instrument and service air systems.

2.2. ELECTRICAL SYSTEMS

2.2.1. Conceptual Design

Each unit has a dedicated main power transformer (MPT), stepping up the voltage to 115 kV. Unit 5 is connected via overhead conductor, and Unit 6 is connected via underground cable. The four MPTs associated with the steam plant (Units 7–10) are connected to the 115-kV switchyard via underground cable. Additionally, there are three common emergency station service transformers (ESST) that connect to the 38-kV switchyard via underground cable and provide service to the plant. Each ESST provides service to two units.

The gas turbine generator (GTG) and STG for Unit 5 are each connected via isolated phase bus to a dedicated winding in the Unit 5 step up transformer. The isolated phase bus for the GTG also has two separate taps connecting to the static exciter and the unit auxiliary transformer. The STG is furnished with a generator circuit breaker, but the GTG is not. The configuration of Unit 6 is similar to that of Unit 5.

The unit auxiliary transformers for Units 5 and 6 step down the generation voltage to 4.16 kV, and each feeds a switchgear bus that is dedicated to the respective unit. In addition to the unit switchgear buses, there is an additional 4.16-kV bus, which is common to both units and provides power to balance-of-plant loads as well as backup power to the unit buses in case of a loss of its normal power source. The common bus receives its power directly from the 38-kV substation through a stepdown transformer or from the Plant's No. 2 fuel oil generators.

The 4.16-kV switchgear buses power the 4.16-kV motor control centers that feed larger motors. The switchgear also powers low-voltage switchgear through low-voltage auxiliary transformers that in turn feed motor control centers located throughout the Plant.

The generator step-up transformers for both Units 5 and 6 are three-winding. They each have the GTG and STG connected to the two low-voltage windings and step up their voltage to deliver their power to the 115-kV substation. They are rated 300/85/215 MVA, FOA, 115 kV-13.8 kV-13.8 kV.

The four generator step-up transformers for Units 7–10 are rated at 84/112/140 MVA at voltage 115 kV-13.8 kV.

2.2.2. Switchyard and Interconnection

The 115-kV and 38-kV switchyards are located just south of the power block. The existing demarcation point for San Juan is on the low side of the MPT and the ESSTs due to the division of responsibility on the maintenance of the large power transformers. All maintenance on the large power transformers is performed by the conservation group within PREPA's substation group; this includes the MPTs, ESSTs, and normal station service transformers.

Engineering design is planned to identify and further separate the Plant from the PREPA transmission and distribution system. A high-level review of the separation required work is included in Sargent & Lundy's report TD-0003, "Demarcation of PREPA Generation Assets from the Transmission and Distribution System" [2].

There is also a gas-insulated substation (GIS) building on the Plant premises. The installation of the 115-kV GIS equipment at the Plant was started in the 2008 timeframe but was never completed. The associated GIS building was completed and contains both the 38-kV and 115-kV GIS equipment. The 38-kV GIS equipment is presently being planned to be placed in service. Portions of the 115-kV GIS equipment have been installed in the GIS building, but the installation was not completed and equipment was not placed in service. Based on the equipment supplier and Sargent & Lundy's observations, the equipment is outdated and should be replaced with a new GIS.

The existing GIS building sustained minor damage during Hurricane Maria but is suitable to house the existing 38-kV GIS equipment and the installation of new 115-kV GIS equipment. Installation of the new

115-kV GIS equipment will require some modifications of the building, such as new floor openings, to allow cable entrance to the equipment and may require localized floor reinforcement.

Future generation plans may require the installation of a new GIS building. The existing building lacks sufficient space to accommodate the additional future GIS breakers. The existing building cannot be expanded due to space constraints both for the building and transmission and generation connections. This project is currently ongoing and is expected to begin construction by the end of 2021.

Finally, there is currently an underground sea cable, 115-kV Line 38000, that is part of a planned San Juan underground loop. The loop will connect seven stations around the San Juan area. This underground sea cable was damaged by a contractor dredging in the channel. PREPA is assessing the damage and scope of repair. The underground loop requires both Line 38000 and the San Juan 115-kV GIS be energized to take full advantage of the loop.

2.3. CONTROL SYSTEMS

The control system is centralized within the main control room areas using a distributed control system (DCS), which is an Emerson OVATION plant DCS platform. The DCS provides continuous and sequential recordings and control capabilities in one integrated system. The system monitors, logs, alarms, and trends the Plant equipment. Status of the equipment is provided in the human-machine interface screen in the control room. The DCS also interfaces with the GT and ST control systems for monitoring and alarms.

The GTG and ST controls are part of the OEM equipment package. The system is microprocessor-based, with controls to interface with the DCS through a Modbus connection, with hardwiring as required.

The continuous emissions monitoring system (CEMS) for Units 5 and 6 was replaced in October 2020. This included moving the database to the new server, reconfiguration of the network, and the following:

- Replacement of one server
- Three new workstations
- Six new programmable logic controllers (PLCs) and instrument cabinets

The boiler control system is currently being upgraded and is expected to be completed in February 2021. This includes:

- Five new servers
- 12 new workstations and 31 monitors
- Cybersecurity servers

2.4. STRUCTURES

There are several structures on site, including the administrative building, GIS building, turbine hall/auxiliary buildings (Units 9 and 10, Units 5–8), three warehouses, and a large mechanical and machine shop.

The administration building is a multistory structure. The main offices are located here with an elevator, conference rooms, and support staff offices. The building provides access to the original turbine hall building, now currently the Unit 5 and Unit 6 turbine hall. The building is dated but in serviceable condition.

The machine-shop equipment and capabilities are extensive and of a high quality that is not typically found outside PREPA facilities. The workshops have considerable expertise and do many of the maintenance activities in house.

3. EQUIPMENT CONDITION

The condition assessment of the Plant is a descriptive summary of the main equipment, facilities, balance of plant, and site-specific items of interest. The units are discussed individually, as a group where reasonable, or as a combined facility for common infrastructure assessment where applicable.

3.1. CONDITION ASSESSMENT

3.1.1. Methodology

Based on interviews, walkdowns, and data gathered on site and sent by PREPA, Sargent & Lundy developed a high-level overall condition assessment for each of the units using a scoring matrix. The matrix is comprised of six major categories: safety hazards, corrosion control, mechanical assessment, electrical assessment, instrumentation and controls assessment, and civil and structural assessment. A short description of each category is as follows:

1. **Safety Hazards**—Based on visual observations during walkdowns from experienced engineering staff
2. **Corrosion Control**—In consideration of the proximity to the coast and with respect to maintenance planning, capital costs, safety, and reliability
3. **Mechanical Assessment**—A high-level review of all major mechanical equipment and systems
4. **Electrical Assessment**—A high-level review of all major electrical equipment and systems
5. **Instrumentation and Controls Assessment**—A high-level review of all major instrumentation and controls equipment and systems
6. **Civil and Structural Assessment**—A high-level review of all major civil and structural equipment and systems

Each of the above categories was scored after Sargent & Lundy's site visits and includes a combination of visual assessment, interviewing, and data review as indicated in the scoring tables. It should be noted that the GIS review was not in this scope and is therefore not included in this condition assessment. The point scoring system for this assessment is defined in Table 3-1.

Table 3-1 — High-Level Condition Assessment Point Scoring System

	Like new (replaced or refurbished within the past five years)
	Maintained with general O&M on a routine basis; no major issues noted
	Deficiency noted or components out of service
	Major issues noted, causing a safety, reliability, or unit output issue
	Not in operation due to end of life

As part of a consent decree with the EPA, each unit is mandated to take an environmental outage at intervals of 12–18 months. The outage is discussed further in Section 5.2.2. Sargent & Lundy assumed that all required maintenance activities are conducted during each mandatory environmental outage except where in progress is noted. This key assumption was used in the evaluation of each of the six major condition assessment categories listed above.

3.1.2. Condition

Two San Juan major common systems scored just below industry averages because one of four circulating water screens was out of service and it was unclear when it may be put back into service. This screen has reached its end of life and may potentially impact the facilities' reliability and unit output based on its reduced redundancy. In addition, the demineralized water treatment system is a rental system, and a permanent installation will not be incorporated in the near future.

3.1.2.1. Unit 5 and 6

Units 5 and 6 score just above industry averages in the overall condition results for the units' end of life, reliability, and output. The current major issue is that the Units 5 and 6 STs are not able to run at full capacity. Interviews with personnel, including staff engineers, indicate that the bypass valves are leaking, and a significant amount of steam is being dumped directly to the cold reheat and condenser. Staff indicated the turbines cannot operate at a full load output of 65 MW and are both limited to 50 MW each. The staff engineers are in discussions with the valve manufacturer to fix the valve seats, check actuator sizing, and confirm if there is any other issue causing an ST de-rate. Due to the magnitude of the consistent turbine de-rate, leak sources beyond the bypass valves will need to be checked for additional problems associated with the steam side delivery. PREPA is in the process of developing a replacement specification for these valves.

There are reliability issues with the feedwater pumps, and spare parts and service support for the pumps has been inconsistent. Current critical pump issues include the HP Boiler Feedwater Pump 6-B having imbalanced impeller blades and having rotating looseness in a motor bearing. Pump replacement parts are currently in order for Pump 6-B.

The Unit 5 generator stator was fully rewound in 2020. The Unit 6 generator stator and rotor was fully rewound in 2020.

The condition of the major electrical equipment at the Plant is consistent with its age. Most of the major electrical equipment is original, but some equipment has been replaced as needed. All generators, power transformers, switchgear, batteries, and relays undergo periodic maintenance and testing. The results from the latest gas analysis of Transformer NSST-U5 show elevated levels of acetylene, which PREPA indicated has been addressed and is no longer an issue.

The results from the 2018 gas analysis of Transformer MPT-U5 showed evidence of cellulose overheating, which PREPA indicated has been addressed and is no longer an issue. A more recent gas analysis results were not provided for review.

Table 3-2 — Unit 5 and 6 Overall Condition Assessment

Item	System	Assessment Method			Scoring Category				Notes
		Visual	Interview	Data	End of Life	Reliability	Unit Output	Subtotal	
1	**Safety Hazards**	yes	no	no					Nothing to note.
2	**Corrosion Control**	yes	no	no					Nothing to note.
3	**Overall Cleanliness & Housekeeping**	yes	no	no					Nothing to note.
4	**Mechanical Assessment**								
4.1	Steam Generator (boiler/HRSG)	yes	yes	no					Minor hot spots visually spotted during walkdown but no other major issues noted. HRSG inspection proposal is in process.
4.2	Combustion Turbine	yes	yes	no					Nothing to note.
4.3	High Energy Piping (HEP)	no	yes	no					No issues noted but limited information provided.
4.4	Condensate System	yes	yes	no					No issues noted with the condensate system.
4.5	Feedwater System	no	yes	no					Reliability issue with parts and service of the pumps. Replacement proposals are being evaluated.
4.6	Turbine and Auxiliaries	no	yes	no					Derate of ST to be resolved
4.7	Circulating Water and Aux Systems	yes	yes	no					Nothing to note. CCW CT replacement proposals are being considered.
4.8	Station Air System	yes	yes	no					No issues with station air and each units station air is shared between the other units
4.9	Emission controls	no	yes	no					No emissions controls installed
4.10	Fuel Systems	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
4.11	Seawater Intake	no	no	no					3 of 4 circulating water traveling screens were in service
4.12	Water Treatment	yes	yes	no					Water treatment system is currently a temporary system and permanent installation does not appear to be incorporated in the near future
4.13	Underground Piping	no	yes	no					No issues noted with the underground piping
4.14	Fire Protection Systems	no	yes	no					No issues noted with the fire protection system
5	**Electrical Assessment**								
5.1	Generator	yes	yes	no					No issues noted during walkdown.
5.2	Transformers	yes	yes	yes					Cellulose overheating in the MPTs. Severe arcing in NSST-U5.
5.3	Switchgear	yes	yes	no					No issues noted during walkdown.
5.4	Protective Relays	yes	yes	no					No issues noted during walkdown.
5.5	Black Start Engines	no	yes	no					No issues noted during walkdown.
6	**Instrument and Controls Assessment**								
6.1	Plant Controls	yes	yes	no					No issues noted during walkdown.
6.2	Turbine Controls	yes	yes	no					No issues noted during walkdown.
7	**Civil / Structural Assessment**								
7.1	Buildings	yes	yes	no					No issues noted with buildings
7.2	Structural Steel	yes	yes	no					No issues noted with structural steel and corrosion
7.3	Tanks / Containment	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
7.4	Cranes	no	yes	no					No issues noted with crane, however replacement proposals are being considered.
8	**Overall Condition Assessment**								System has been maintained with general O&M on a routine basis, no major issues noted

3.1.2.2. Unit 7

Unit 7 is currently out of service due to “Limited Use Condition,” with the last date of operation on July 3, 2020. (See Section 8.1.2 for additional explanation of “Limited Use Condition.”) The mechanical equipment for Unit 7 scored within industry averages, but no inspection reports or remaining useful life assessments provide were from recent years. A substantial history of the boiler repairs and upgrades were available.

Recent work for the Unit 7 boilers includes the following, completed in 2008:

- Front waterwall replacement (elevations 31’ to 92’)
- Right and left waterwall replacement (elevations 18’-6” to 89’-9”)
- Air Preheaters 7-1 and 7-2 replacement

The condition of the major electrical equipment at the Plant is consistent with its age. Most of the major electrical equipment is original and nearing the end of its useful life, but some equipment has been replaced as needed. All generators, power transformers, switchgear, batteries, and relays undergo periodic maintenance and testing.

The results from the 2018 gas analysis of Transformer MPT-U7 show evidence of cellulose overheating, which PREPA indicated has been addressed and no longer an issue. A more recent gas analysis results were not provided for review.

Our overall condition assessment summary of San Juan Unit 7 can be found in Table 3-3.

Table 3-3 — San Juan Unit 7 Overall Condition Assessment

Item	System	Assessment Method			Scoring Category				Notes
		Visual	Interview	Data	End of Life	Reliability	Unit Output	Subtotal	
1	**Safety Hazards**	no	no	no					Nothing to note.
2	**Corrosion Control**	no	no	no					Corrosion typical of coastal exposed equipment
3	**Overall Cleanliness & Housekeeping**	yes	no	no					Nothing to note.
4	**Mechanical Assessment**								
4.1	Steam Generator (boiler/HRSG)	no	yes	no					Current not in service to due "Limited Use Condition", last date of operation was July 3, 2020
4.2	FD and ID Fans and Auxiliaries	no	yes	no					No issues noted for the fans and auxiliaries. FGR fans are no longer in services but are not needed to steam temperature control.
4.3	High Energy Piping (HEP)	no	yes	no					No issues noted but limited information provided.
4.4	Condensate System	yes	yes	no					Condensate was recently cleaned and no other major issues noted.
4.5	Feedwater System	yes	yes	no					No issues noted with the feedwater system
4.6	Turbine and Auxiliaries	no	yes	no					No issued noted with the turbine and auxiliaries
4.7	Circulating Water and Aux Systems	yes	yes	no					3 of 4 circulating water traveling screens were in service
4.8	Station Air System	yes	yes	no					No issues with station air and each units station air is shared between the other units
4.9	Emission controls	no	yes	no					No emissions controls installed
4.10	Fuel Systems	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
4.11	Seawater Intake	no	no	no					3 of 4 circulating water traveling screens were in service. Head limitation issue during low sealevels
4.12	Water Treatment	yes	yes	no					Water treatment system is currently a temporary system and permanent installation does not appear to be incorporated in the near future
4.13	Underground Piping	no	yes	no					No issues noted with the underground piping
4.14	Fire Protection Systems	no	yes	no					No issues noted with the fire protection system
5	**Electrical Assessment**								
5.1	Generator	yes	yes	no					No issues noted during walkdown.
5.2	Transformers	yes	yes	yes					MPT shows evidence of cellulose overheating.
5.3	Switchgear	yes	yes	no					No issues noted during walkdown.
5.4	Protective Relays	yes	yes	no					No issues noted during walkdown.
5.5	Black Start Engines	no	yes	no					No issues noted during walkdown.
6	**Instrument and Controls Assessment**								
6.1	Plant Controls	yes	yes	no					No issues noted during walkdown.
6.2	Turbine Controls	yes	yes	no					No issues noted during walkdown.
7	**Civil / Structural Assessment**								
7.1	Buildings	yes	yes	no					No issues noted with buildings
7.2	Structural Steel	yes	yes	no					No issues noted with structural steel and corrosion
7.3	Tanks / Containment	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
7.4	Cranes	yes	yes	no					Unit 7 crane was recently repaired and certified for use.
8	**Overall Condition Assessment**								Deficiency were noted or components were out of service

3.1.2.3. Unit 8

Unit 8 is available for emergency use only due to the mercury and air toxics standards (MATS) operating limits (33 days remaining until April 2021), with the last date of operation on September 15, 2020. See Section 8.1.2 for an additional explanation of MATS requirements. The mechanical equipment for Unit 8 scored within industry averages, but no inspection reports or remaining useful life assessments were recent. A substantial history of the boiler repairs and upgrades are available.

Recent work for the Unit 8 boilers includes the following, which were completed in 2010:

- Furnace Bottom H-1 header replacement
- Replacement of left and right desuperheater assemblies and liners
- Air preheater overhaul and basket replacement
- Windbox baffles installation

The condition of the major electrical equipment at the Plant is consistent with its age. Most of the major electrical equipment is original and nearing the end of its useful life, but some equipment has been replaced as needed. All generators, power transformers, switchgear, batteries, and relays undergo periodic maintenance and testing.

The results from the latest gas analysis of Transformer NSST-U8 shows evidence of moderate partial discharge in the oil. These conditions should be monitored and rechecked every three months. The dryness of the oil is still acceptable for continued use, but there may be some limitations when used in an overload situation.

The results from the 2018 gas analysis of Transformer MPT-U8 show evidence of cellulose overheating, which PREPA indicated has been addressed and is no longer an issue. More recent gas analysis results were not provided for review.

Our overall condition assessment summary of San Juan Unit 8 can be found in Table 3-4.

Table 3-4 — San Juan Unit 8 Overall Condition Assessment

Item	System	Assessment Method			Scoring Category				Notes
		Visual	Interview	Data	End of Life	Reliability	Unit Output	Subtotal	
1	**Safety Hazards**	no	no	no					Nothing to note.
2	**Corrosion Control**	no	no	no					Corrosion typical of coastal exposed equipment
3	**Overall Cleanliness & Housekeeping**	yes	no	no					Nothing to note.
4	**Mechanical Assessment**								
4.1	Steam Generator (boiler/HRSG)	no	yes	no					Current not in service to due "Limited Use Condition", last date of operation was September 15, 2020
4.2	FD and ID Fans and Auxiliaries	no	yes	no					No issues noted for the fans and auxiliaries. FGR fans are no longer in services but are not needed to steam temperature control.
4.3	High Energy Piping (HEP)	no	yes	no					No issues noted but limited information provided.
4.4	Condensate System	yes	yes	no					Condensate was recently cleaned and no other major issues noted.
4.5	Feedwater System	yes	yes	no					No issues noted with the feedwater system
4.6	Turbine and Auxiliaries	no	yes	no					When operating, performance is derated with less output at approximately 88 MW. Turbine has experienced solid particle erosion in steam chest and internal components. There has been water in lube oil due to seal leakage.
4.7	Circulating Water and Aux Systems	yes	yes	no					1 pump is out of service.
4.8	Station Air System	yes	yes	no					No issues with station air and each units station air is shared between the other units
4.9	Emission controls	no	yes	no					No emissions controls installed
4.10	Fuel Systems	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
4.11	Seawater Intake	no	no	no					3 of 4 circulating water traveling screens were in service. Head limitation issue during low sealevels
4.12	Water Treatment	yes	yes	no					Water treatment system is currently a temporary system and permanent installation does not appear to be incorporated in the near future
4.13	Underground Piping	no	yes	no					No issues noted with the underground piping
4.14	Fire Protection Systems	no	yes	no					No issues noted with the fire protection system
5	**Electrical Assessment**								
5.1	Generator	yes	yes	no					No issues noted during walkdown.
5.2	Transformers	yes	yes	yes					MPT and NSST show evidence of cellulose overheating and partial discharge.
5.3	Switchgear	yes	yes	no					No issues noted during walkdown.
5.4	Protective Relays	yes	yes	no					No issues noted during walkdown.
5.5	Black Start Engines	no	yes	no					No issues noted during walkdown.
6	**Instrument and Controls Assessment**								
6.1	Plant Controls	yes	yes	no					No issues noted during walkdown.
6.2	Turbine Controls	yes	yes	no					No issues noted during walkdown.
7	**Civil / Structural Assessment**								
7.1	Buildings	yes	yes	no					No issues noted with buildings
7.2	Structural Steel	yes	yes	no					No issues noted with structural steel and corrosion
7.3	Tanks / Containment	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
7.4	Cranes	yes	yes	no					Crane was recently repaired and certified for use.
8	**Overall Condition Assessment**								Deficiency were noted or components were out of service

3.1.2.4. Unit 9

Unit 9 is available for service but is de-rated to 90 MW due to a boiler leak issue. Details of this issue were not provided for review. Sargent & Lundy's overall condition assessment summary of San Juan Unit 9 can be found in Table 3-5. Major observations are discussed below.

The mechanical equipment for Unit 9 scored within industry averages, but no recent inspection reports or remaining useful life assessments were provided for review. A substantial history of the boiler repairs and upgrades are available. This information is critical in determining the overall life assessment and its impact to unit reliability and output for the near future.

Recent work for the Unit 9 boilers includes the following, which were completed in 2012:

- Front waterwall tube replacement (29 tubes, elevation 15–24')
- Air preheater basket replacement

The condition of the major electrical equipment at the Plant is consistent with its age. Most of the major electrical equipment is original and nearing the end of their useful life, but some equipment has been replaced as needed. All generators, power transformers, switchgear, batteries, and relays undergo periodic maintenance and testing. The results from the 2018 gas analysis of Transformer MPT-U9 show presence of a low volume of combustible gases in the oil. These conditions are not an immediate concern but should be rechecked every six months. The dryness of the insulation is moderately wet, which may indicate leaks or compromised gaskets and preservation systems; however, more recent gas analysis results were not provided for review.

Table 3-5 — San Juan Unit 9 Overall Condition Assessment

Item	System	Assessment Method			Scoring Category				Notes
		Visual	Interview	Data	End of Life	Reliability	Unit Output	Subtotal	
1	**Safety Hazards**	no	no	no					Nothing to note.
2	**Corrosion Control**	no	no	no					Corrosion typical of coastal exposed equipment
3	**Overall Cleanliness & Housekeeping**	yes	no	no					Nothing to note.
4	**Mechanical Assessment**								
4.1	Steam Generator (boiler/HRSG)	yes	yes	no					The status of Unit 9 is currently unknown.
4.2	FD and ID Fans and Auxiliaries	no	yes	no					No issues noted for the fans and auxiliaries. FGR fans are no longer in services but are not needed to steam temperature control.
4.3	High Energy Piping (HEP)	no	yes	no					No issues noted but limited information provided.
4.4	Condensate System	yes	yes	no					Condensate was recently cleaned and no other major issues noted.
4.5	Feedwater System	no	yes	no					No issues noted with the feedwater system
4.6	Turbine and Auxiliaries	no	yes	no					No issued noted with the turbine and auxiliaries
4.7	Circulating Water and Aux Systems	yes	yes	no					1 Pump is out of service
4.8	Station Air System	yes	yes	no					No issues with station air and each units station air is shared between the other units
4.9	Emission controls	no	yes	no					No emissions controls installed
4.10	Fuel Systems	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
4.11	Seawater Intake	no	no	no					3 of 4 circulating water traveling screens were in service.
4.12	Water Treatment	yes	yes	no					Water treatment system is currently a temporary system and permanent installation does not appear to be incorporated in the near future
4.13	Underground Piping	no	yes	no					No issues noted with the underground piping
4.14	Fire Protection Systems	no	yes	no					No issues noted with the fire protection system
5	**Electrical Assessment**								
5.1	Generator	yes	yes	no					No issues noted during walkdown.
5.2	Transformers	yes	yes	yes					Bushings were recently replaced and transformer is in service working properly.
5.3	Switchgear	yes	yes	no					No issues noted during walkdown.
5.4	Protective Relays	yes	yes	no					No issues noted during walkdown.
5.5	Black Start Engines	no	yes	no					No issues noted during walkdown.
6	**Instrument and Controls Assessment**								
6.1	Plant Controls	yes	yes	no					No issues noted during walkdown.
6.2	Turbine Controls	yes	yes	no					No issues noted during walkdown.
7	**Civil / Structural Assessment**								
7.1	Buildings	yes	yes	no					No issues noted with buildings
7.2	Structural Steel	yes	yes	no					No issues noted with structural steel and corrosion
7.3	Tanks / Containment	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
7.4	Cranes	no	yes	no					No issues noted with crane.
8	**Overall Condition Assessment**								Deficiency were noted or components were out of service

3.1.2.5. Unit 10

Unit 10 has been in and out of service for approximately four years due to several issues on the turbine but is currently in a long-term outage. In 2016, high-vibration and bearing issues were noted that resulted in damage to the LP turbine. A root-cause analysis determined that the damage was attributed to the shroud band coming loose during operation. The Plant is currently in litigation with the contractor that performed the work, and the unit has been out of service since.

The Plant also indicated that the boiler was drained and dried after this incident, but its layup process was not documented. The mechanical equipment for Unit 10 scored well below industry averages due to the major issues discussed below. There are concerns of the overall condition of the boiler and all auxiliary equipment since the unit has not been operational for approximately four years. The unit is out of service, and major inspections are needed for the flue-gas and water sides of the unit as well as the turbine auxiliaries since its overall condition is a concern. The current timeline for the turbine litigation is not known; however, it is unlikely the turbine will be repaired for operation. No recent inspection reports or remaining useful life assessments were provided for review. A substantial history of the boiler repairs and upgrades are available.

Recent work for the Unit 10 boiler includes the following, which were completed in 2009:

- Secondary superheater assembly replacement
- Preheater assembly replacement
- Burner replacement
- Air preheater basket replacement

The condition of the major electrical equipment at the Plant is consistent with its age. Most of the major electrical equipment is original and nearing the end of their useful life, but some equipment has been replaced as needed. All generators, power transformers, switchgear, batteries, and relays undergo periodic maintenance and testing. The results from the latest gas analysis of Transformer NSST-U10 show evidence of cellulose overheating, which PREPA indicated has been addressed and is no longer an issue. These condition are not an immediate concern but should be rechecked every 12 months.

Additionally, the results from the 2018 gas analysis of Transformer MPT-U10 show evidence of cellulose overheating, which PREPA indicated has been addressed and is no longer an issue. These conditions are generally not an immediate concern but should be rechecked every six months. The dryness of the insulation is wet, which is a problem because it substantially increases the aging of cellulosic insulation; however, more recent gas analysis results were not provided for review.

Our overall condition assessment summary of San Juan Unit 10 can be found in Table 3-6.

Table 3-6 — Unit 10 Overall Condition Assessment

Item	System	Assessment Method			Scoring Category				Notes
		Visual	Interview	Data	End of Life	Reliability	Unit Output	Subtotal	
1	**Safety Hazards**	yes	no	no					Nothing to note.
2	**Corrosion Control**	yes	no	no					Corrosion typical of coastal exposed equipment
3	**Overall Cleanliness & Housekeeping**	yes	no	no					Nothing to note.
4	**Mechanical Assessment**								
4.1	Steam Generator (boiler/HRSG)	yes	yes	no					Unit 10 has been out of service for approximately 4 years. The boiler doors were left open and corrosion is visually seen on heat transfer components. The unit has been drained of water but the boiler and auxiliaries were never layed up. Major inspections are needed and is very concerning that the unit has not been layed up properly.
4.2	FD and ID Fans and Auxiliaries	no	yes	no					No issues noted for the fans and auxiliaries. FGR fans are no longer in services but are not needed to steam temperature control.
4.3	High Energy Piping (HEP)	no	yes	no					No issues noted but limited information provided.
4.4	Condensate System	no	yes	no					No layup procedure applied to equipment. Concerns on overall condition of the system.
4.5	Feedwater System	no	yes	no					No layup procedure applied to equipment. Concerns on overall condition of the system.
4.6	Turbine and Auxiliaries	no	yes	no					The turbine repairs/modifications are currently under litigation. The LP side of the turbine was damaged.
4.7	Circulating Water and Aux Systems	yes	yes	no					3 of 4 circulating water traveling screens were in service. 1 Pump out of service
4.8	Station Air System	yes	yes	no					No issues with station air and each units station air is shared between the other units
4.9	Emission controls	no	yes	no					No emissions controls installed
4.10	Fuel Systems	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
4.11	Seawater Intake	yes	no	no					3 of 4 circulating water traveling screens were in service.
4.12	Water Treatment	yes	yes	no					Water treatment system is currently a temporary system and permanent installation does not appear to be incorporated in the near future
4.13	Underground Piping	no	yes	no					No issues noted with the underground piping
4.14	Fire Protection Systems	no	yes	no					No issues noted with the fire protection system
5	**Electrical Assessment**								
5.1	Generator	yes	yes	no					No issues noted during walkdown.
5.2	Transformers	yes	yes	yes					MPT and NSST show evidence of cellulose overheating.
5.3	Switchgear	yes	yes	no					No issues noted during walkdown.
5.4	Protective Relays	yes	yes	no					No issues noted during walkdown.
5.5	Black Start Engines	no	yes	no					No issues noted during walkdown.
6	**Instrument and Controls Assessment**								
6.1	Plant Controls	yes	yes	no					No issues noted during walkdown.
6.2	Turbine Controls	yes	yes	no					No issues noted during walkdown.
7	**Civil / Structural Assessment**								
7.1	Buildings	yes	yes	no					No issues noted with buildings
7.2	Structural Steel	yes	yes	no					No issues noted with structural steel and corrosion
7.3	Tanks / Containment	yes	yes	no					One tank is out of service but not needed for reliability or to maintain unit output.
7.4	Cranes	no	yes	no					No issues noted with crane.
8	**Overall Condition Assessment**								Major issues noted causing a safety, reliability or unit output issue

3.2. RECOMMENDATIONS

Recommendations for the Plant focus on three elements of the facility: the combined-cycle group, the thermal-plant group, and the common-systems group. In the previous sections, the unit's age and designs have been addressed where appropriate. The discussion in this section will concentrate on what to rectify, upgrade, or replace as applicable.

3.2.1. Combined-Cycle Recommendations for Unit 5 and 6

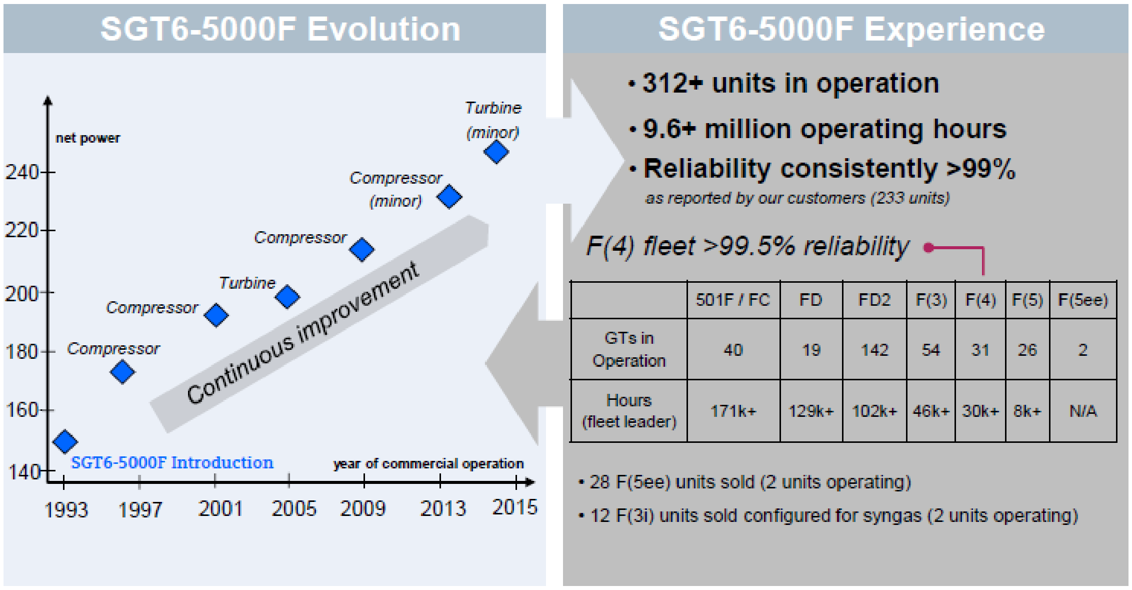
The Units 5 and 6 combined-cycle plants are now designed to fire dual fuels and are in overall good condition, as expected for units recently installed (2008). The equipment is still functioning, and corrosion on the unit and system auxiliary equipment has not occurred.

Required repairs and minor items noted during the walkdowns are expected to be addressed during normal maintenance outages and online as appropriate. The Plant performs this type of work in house with their staff and facilities on a regular basis. There are a few items that have design changes and heat rate issues, which are highlighted below.

The GT units have multiple upgrade possibilities to consider. Shortly after initial procurement of the San Juan units in 1997, Siemens acquired the Westinghouse product line (mid-1998) and continued to make several technological advances. The current Siemens designation of this GT model is the SGT6-5000F. The following provides background information and the upgraded design features that may be available for future consideration. This discussion is presented to illustrate available upgrades should PREPA or other interested parties desire additional output and improved performance.

Beginning as a Westinghouse design (W501FA), the first "F Technology" GT went into commercial operation in 1993 at a nominal 150 MW. For more than two decades, there have been continuous improvements in the technology throughout the compressor and hot gas path sections based on proven designs of Westinghouse "W" and Siemens "V" engines. Also, driven by the power generation market conditions, Siemens integrated features into their GT designs that permit fast startups and restarts. Table 3-7 and Table 3-8 summarize these upgrades and modifications, with noted electrical output improvements and a summary of the improvements associated with the stated upgrade or modification.

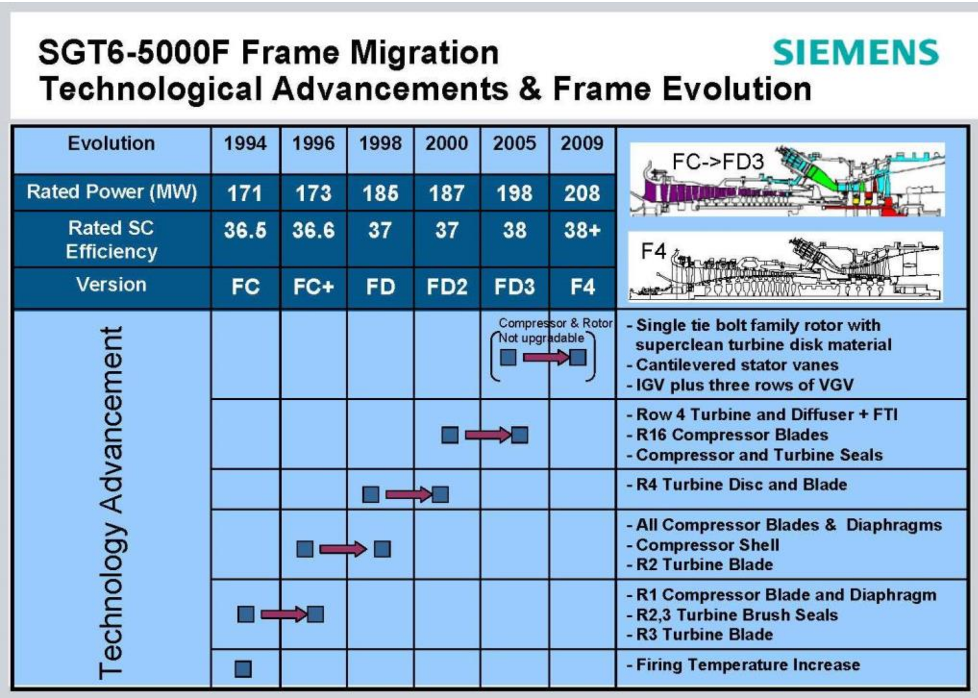
Table 3-7 — Evolution of Westinghouse/Siemens W501F/SGT6-5000F — Power vs. Year



	501F / FC	FD	FD2	F(3)	F(4)	F(5)	F(5ee)
GTs in Operation	40	19	142	54	31	26	2
Hours (fleet leader)	171k+	129k+	102k+	46k+	30k+	8k+	N/A

Source: Siemens Literature | **Note:** The original Westinghouse designs FC–FD(3) compressor and rotor are not upgradeable to the Siemens SGT6-5000F(4/5) compressor and rotor configuration.

Table 3-8 — Evolution of Westinghouse/Siemens W501F/SGT6-5000F — Technology Modifications



Evolution	1994	1996	1998	2000	2005	2009
Rated Power (MW)	171	173	186	187	198	208
Rated SC Efficiency	36.5	36.6	37	37	38	38+
Version	FC	FC+	FD	FD2	FD3	F4

Source: Siemens Literature

Upgrades to the GTs will also require condition and capability assessments of the HRSG, ST, and balance-of-plant equipment due to increased loads (i.e., higher flows, pressures, temperatures, and electrical output), especially HRSG HP and high-temperature parts.

As previously noted, the Units 5 and 6 STs have a 15-MW de-rate. This long-term issue has not been completely identified, and it is likely there are multiple contributors to it. Damaged bypass valve seats (both HP and hot-reheat bypasses) have been identified as a potential source and are currently in the process of being corrected. Sargent & Lundy recommends that a complete energy evaluation be conducted on Units 5 and 6. The evaluation will include cycle isolation testing for leaks and drains and determining the steam flows and operating parameters. Where there are issues with performance, they must be identified, and the issues can then be traced back to the root causes and corrected.

Part of the issue may also be found in the steam vents and drains. Significant continuous steam was discharging from the HRSG blowdown tanks during December 2018. Unit 5 was in turbine bypass mode due to a temporary water quality issue, but Unit 6 was in normal operation. Also, due to the proximity of the HRSG elevator and drum level platforms, the blowdown tank steam vent discharge point should be evaluated for extension to an elevation or location away from walkways. This would alleviate a potential safety and maintenance issue, as the frequent steam contact with the sides of the HRSG and nearby equipment will hasten corrosion of the subjected areas.

Inspections for the HRSGs are also being considered by the staff to evaluate tube and internal system conditions. Sargent & Lundy recommends they proceed with the inspections and determine further action for the units.

The cooling towers for the closed cooling system are also being considered for replacement, and the staff has proposals in house for replacement designs. Sargent & Lundy recommends they proceed with replacement for increased reliability.

Figure 3-1 — Blowdown Steam Vent Unit 5 (Left) and Unit 6 (Right)

3.2.2. Thermal Plant Recommendations for Units 7–10

The thermal plants, Units 7–10, are of similar design. The open-boiler concept, which was a common design at the time of installation, is not well suited for the aggressive marine environment. The open-boiler concept is an economical design featuring mostly unprotected piping, equipment, and lagging; however, it is highly susceptible to the environment. Cycling and long-term disuse further exacerbate the issue. As a result of this design, corrosion is prevalent across many areas of the installation of Units 7–10, including structural steel, and as a result, they are approaching the end of their useful life.

The thermal units are older, and the design predates many modern emissions technology requirements. Environmental retrofit would be uneconomical given the age of the units, and rebuilding with a similar design, even if updated, would not make sense. Sargent & Lundy recommends Units 7–10 be phased out of service. The retirement can be coordinated with expected fuel-gas availability at the site and can involve reclaiming the HFO storage areas for other uses. PREPA plans to retire these facilities in the next five years. Units 7–10 could be replaced by a plant with capacity and flexibility as determined by a separate load demand and resource study. A newer plant could take advantage of cleaner technologies currently offered by OEMs.

While it is recommended these units be replaced, the Plant has multiple benefits to consider for reuse or repurposing. The site location is near the city of San Juan, which is a major load demand center, and it can serve the populace without extensive transmission exposure. Additional features, other than location, to consider for future site use include the existing GIS facility, existing intake and discharge structures, existing buildings, and ample site space following the reclaiming of HFO storage areas and other plant areas that will be freed up pending the retirement of Units 7–10. As described in the next subsection, the intake and discharge structures may be repurposed for a future plant design.

Replacement of Units 7–10 has potential for more efficient, cleaner, combined-cycle plant design possibly coupled with a hybrid configuration for instantaneous power. Smaller, rapid-start GT equipment with purge credit, battery storage, and other features would provide higher-density power coupled with rapid response for a future grid that integrates a larger amount of renewable power. Natural gas would be a practical choice to repower the Plant and could provide tremendous environmental improvements over the current HFO and No. 2 fuel operation of Units 7–10.

3.2.3. Common Systems Recommendations

PREPA is studying the need for additional grid support and generation throughout the island. Although a plan for additional generation at the site has not been identified, the common systems of raw water, demineralized water, condensate, fire protection, circulating water, and auxiliary steam can be evaluated for use after retirement of Units 7–10. The balance-of-plant capacities required at the site, pending future additional or less power generation, will vary based on the final determination of the site capacity.

The following recommendations should be considered for each of the significant systems. The recommendations are given in the anticipation that a similar generation plant, of equivalent nameplate electrical power, will be provided and maintained at the site.

The raw-water system capacity and the final water treatment system (including RO and a demineralizer) solution should be evaluated for similar capacity, either higher or lower, for the site. Cycling and Plant design will need to be identified for overall water requirements. Individual water-storage tank areas will need to be assessed for potential reuse with new generation layouts. Two demineralized-water tanks and two raw-water tanks were installed with the addition of Units 5 and 6 and should be maintained when considering a new plant design.

The fire protection system will need to be evaluated for a potentially larger flow rate. Most units in comparable sites have a minimum 2,000–2,500 gpm electric and No. 2 fuel oil pumps separated by a firewall and a corresponding two-hour storage tank capacity. The design of the ST underfloor protection system will typically govern the maximum water flow rate, on which the final recommendation for larger equipment will be dependent. The underground piping layout has large loops and may accommodate an alternate plant footprint without significant rework. The underground system should be evaluated for life extension prior to modification.

The circulating-water system has multiple interfaces with the units. Unit 5 and 6 share common intake and discharge with Units 7 and 8. There have been issues with recirculation from the discharge back to the intake due to the configuration. Sargent & Lundy recommends that the intake and discharges be evaluated for either a tie-in with the Unit 9 and 10 intake—which is separated from the discharges by a small jetty—or a possible upgrade to a different cooling method such as a cooling tower with lower water requirements. For a cooling tower makeup arrangement, instead of the current once-through design, much of the once-though system would not be required and could be replaced with a smaller updated system with appropriate materials. The redesign can take advantage of the intake location without using the older concrete structures and tunnels throughout the Plant.

When required for startup, auxiliary steam is provided by a unit in operation. Auxiliary steam is provided for steam-unit deaerator pegging, HRSG pre-warming, and gland steam to speed the startup process. The addition of an auxiliary boiler should be evaluated for startup of Units 5 and 6 and for any foreseeable future units. The evaluation should consider unit dispatch and response times for the anticipated load and generation required.

4. INFRASTRUCTURE AND INTERCONNECTIONS

4.1. STEAM SUPPLY

The Auxiliary Steam System is interconnected between the units, with the older units able to provide auxiliary steam for gland seals and deaerator heating and pegging to Units 5 and 6 and vice versa.

4.2. NATURAL GAS SUPPLY

On March 5, 2019, PREPA (as the buyer) entered a fuel sale and purchase agreement with NFENERGÍA LLC (as the seller) for the supply of natural gas to Units 5 and 6. The term of the agreement ends five years after the two parties have successfully met their respective firm supply conditions as specified in the agreement.

NFENERGÍA LLC is responsible for supply, delivery, operations, and maintenance of the supply to the delivery point at the Plant boundary. The seller is responsible for providing floating storage units to meet a seven-day storage of liquified natural gas.

4.3. FUEL OIL SUPPLY

4.3.1. Overview

Currently, there are shared services between the HFO systems for Units 7–10 and the No. 2 systems for Units 5 and 6. These systems are detailed in Section 2.1.9.

HFO and No. 2 fuel are delivered to the Plant via the transfer lines from a docking station at the Port of San Juan. Recent (April 2018) certificates of fuel analysis were provided, and no indications of fuel issues were found. The terminal point of the incoming fuel oil is interior of the Plant, located adjacent to the north access road near the carpenter shop.

Detailed inspections of the systems were conducted in 2005. The results of the No. 2 fuel-oil system indicated no issues were found; however, a second inspection suggested for 2007 was not conducted. The HFO system required repairs due to pitting and corrosion. No additional confirmation of completed repairs was available.

Fuel oil for San Juan is provided under two separate agreements: one for HFO and one for No. 2 fuel oil. The HFO contract is with Freepoint Commodities, LLC. The No. 2 fuel oil contract is with Puma Energy Caribe, LLC.

4.3.2. HFO Contract

On July 31, 2015, PREPA entered a fuel oil purchase contract (Contract 902-02-15) with Freepoint Commodities LLC for the supply of HFO to the Aguirre Steam plant, Costa Sur plant, Palo Seco Steam plant, and San Juan. The contract has been extended for additional years through various amendments. PREPA and Freepoint Commodities are currently finalizing a fifth amendment to the contract that will extend the term until October 31, 2021. PREPA plans to seek competitive bids to secure its next contract.

4.3.3. No. 2 Fuel Oil Contract

On November 21, 2019, PREPA entered a contract (Contract 902-01-19) with Puma Energy Caribe, LLC for the supply of No. 2 fuel to all the PREPA plants that operate with this fuel. The original term of the contract was for one year, but the contract includes a provision for an automatic extension upon mutual agreement. PREPA and Puma Energy Caribe are currently finalizing details for the extension of the contract until November 20, 2021. PREPA plans to seek competitive bids to secure its next contract.

4.4. WATER SUPPLY AND TREATMENT

The new water treatment facility is under construction, and as of March 2019, the building was near completion and equipment was being installed. The new facility is shown in Figure 4-1 and is located adjacent to the demineralized-water tanks on the south side of the Plant near the main entrance.

Figure 4-1 — Location of New RO Water Treatment System

Water treatment plant, March 2019

5. OPERATIONS AND MAINTENANCE

The Plant is generally producing power 24 hours a day, seven days a week. The Plant cycles as directed by dispatch, and it is rarely at full load. The Operations Department works three shifts, staffing the Plant 24 hours a day, seven days a week. The staff uses the control rooms as their centers of operation. Daily meetings are used to direct activities and coordinate efforts among the staff. During each shift, the shift engineer is in charge of the Plant operations and management.

Normally, the thermal units operate at 230–430 MW continuously for grid frequency control, and the combined-cycle units operate as base-loaded in either simple-cycle or combined-cycle mode. The STGs are engaged at the combined-cycle facility as often as three times weekly for 10–12 hours at a time.

5.1. STAFFING AND TRAINING

The Plant is composed of four departments that respond to the department head: Operations, Conservation, Administrative, and the General Mechanical Shop. The Operations Department works on three shifts, staffing the Plant 24 hours a day. As of January 2018, there were 163 personnel working at the site. This is typical for a Plant of this size; however, the current staff at the site was not provided for review.

5.2. MAINTENANCE PROGRAMS

5.2.1. Overview

Units 5 and 6 are run as base-loaded. Units 7–10 have had low dispatch, and they are required to have regular outages for maintenance and environmental reasons per the EPA agreement and PREPA management requirements discussed in Section 5.2.2. In general, the frequent scheduled outages provide time for much of the deferred maintenance items. Many maintenance items are delayed as necessary to the next scheduled outage as parts and supplies become available.

Routine maintenance activities are performed during the regular environmental outages. Larger scopes of work requiring a longer outage are also scheduled as needed. Upgrades and significant design modifications are planned during the major overhauls.

The main objective of PREPA's maintenance plan is to use preventative maintenance in conjunction with predictive techniques developed at the plant level. Maintenance is performed using the OEM's specifications, plant experience, plant routine inspections, equipment monitoring, and O&M manuals as applicable. There is not a standing formal service agreement with specialist manufacturers. Agreements are entered as need with the Plant. Each plant has extensive workshop capability, and, to a large part, is mostly self-reliant for equipment repair. Additionally, PREPA signed a long-term service agreement (LTSA) with the GT vendor (Westinghouse/MHPS) on March 15, 2016 for the GTs of Units 5 and 6.

5.2.2. Mandatory Environmental Outage

Each PREPA thermal production plant is mandated to perform an environmental outage at intervals of 12–18 months. During an environmental outage, the boiler and other components are cleaned to meet the requirements of the air compliance preventative maintenance schedule contained in PREPA's consent decree with the EPA. Each plant may keep a unit in service for up to an 18-month limit, subject to the unit's compliance with the emissions criteria in the consent decree.

Several areas, as applicable, are inspected, cleaned, and replaced (if necessary) during each environmental outage:

- At the start of an environmental outage, slag is removed from the boiler and the water walls are cleaned.
- The superheater, reheater, air heater, economizer areas, and the exhaust gas ducts and the stack are washed and inspected.
- Air heater components, seals, baskets, casing, and sector plates are inspected and replaced as necessary. Ductwork is repaired.
- Hoppers are emptied and cleaned, and expansion joints are inspected for corrosion and leakage.
- Fuel handling equipment is inspected, repaired, and recalibrated as necessary.
- The FD and ID fans and the gas recirculation fan are cleaned, noise and vibration levels are monitored, adjustments are made, and repairs are completed.
- Motors for fans and main boiler pumps are cleaned and inspected. Dampers are inspected and adjusted.
- The windbox, burners, combustion air instrumentation, combustion controls, and soot blowers are inspected. Damaged or worn components are either repaired or replaced.
- Monitors for opacity, oxygen, and furnace pressure are cleaned, recalibrated, or replaced as necessary.
- Pumps, feedwater heaters, the deaerator, and associated valves are inspected.
- Lubricating oil systems are inspected.
- Power transformers are inspected, and breakers tested and adjusted.
- If a pressurized part of the boiler has been replaced, the boiler part will be pressure tested before the unit returns to service.

- Life extension inspections and nondestructive examination activities are completed on critical systems and components in preparation for future programmed outages.

Plant personnel indicated that all these maintenance activities are conducted during each environmental outage.

5.2.3. Units 5 and 6 Long-Term Service Agreement

Because the W501F GT was initially developed by a joint venture between Westinghouse and Mitsubishi Heavy Industries, it was appropriate to use the maintenance services of Mitsubishi Hitachi Power Service (MHPS) for the service agreement. PREPA signed an LTSA with the GT vendor (Westinghouse/MHPS). The agreement is to service the machines for a total of 104,000 hours and 112,000 hours for Unit 5 and Unit 6, respectively, during which the vendor will be responsible for the maintenance of the GT generator.

The LTSA was executed on March 15, 2016 and has the following term, per Article 4:

> 4.1 Term
>
> The “Term” of the LTSA shall commence upon execution of the LTSA, (“Effective Date” and shall continue until “LTSA End Date”, which will be the later of: a) the earlier of Unit 5 reaching (i) 104,000 EFH, or (ii) 3,900 ES: (b) the earlier of Unit 6 reaching (iii) 112,000 EFH, or (iv) 4,200 ES for Unit 6, starting both units from First Fire after completion of the last Planned Maintenance Inspection performed on each unit under the Previous LTSA: and (c) the completion of the second Major Inspection (MI) performed on each Covered Unit under this Contract.
>
> 4.2 Sunset Termination
>
> Notwithstanding the foregoing, if the Term has not expired under Article 4.1 by that is fifteen (15) years following the Effective Date (the Sunset Termination Date), this Contract will automatically terminate.

Thus, the LTSA is expected to expire no later than 2031 based on the contract execution date. Actual operating hours based on estimated future are not likely to exceed the maximums; however, contract termination prior to the sunset date based on the operating hours exceeding the contract will need to be confirmed with the OEM and reassessed after another several years of operation.

Since the San Juan GTs have a LTSA with MHPS, any action that is needed on the units is coordinated through the MHPS office. This means the monitoring of Siemens service bulletins is MHPS’s responsibility.

The Plant has no formal tracking process to receive and log Siemens service bulletins, review and prioritize the action required, document the action taken, or record closure.

5.2.4. Preventative Maintenance

Although the LTSA covers the maintenance of the GT generator, PREPA is responsible for the maintenance of the combined-cycle auxiliaries of the Plant. Valve inspections are performed every 18 months. The scope includes the cleaning, nondestructive examination, and adjustment of the HP stop and control valves, reheat stop valves, and intercept valves. Major inspections of the STG are performed per the LTSA.

Units 7–10 (the units with low dispatch) are also required to have regular outages for maintenance and environmental reasons. Many maintenance items are delayed as necessary to the next scheduled outage as parts and supplies become available.

Part requisitions are routed through the main office in San Juan. As parts for the older and less used plants have been prioritized under other and newer plants, part and supply requests have been delayed or deferred as necessary. Site personnel have been conscientious of this and, where recent unforeseen requirements have demanded electrical generation, parts from the unavailable plants have been repurposed to maintain the other units to meet the required loads.

5.2.5. Corrective Maintenance

Corrective maintenance is primarily conducted on an as needed basis. Due to the low dispatch of the units, corrective maintenance for redundant systems can be done online or as required when the unit is not dispatched.

5.2.6. Predictive Maintenance

A predictive maintenance program is used. The program reads and records the vibration recording for the main equipment. Vibration readings were provided for review, and site personnel did not identify abnormalities. In general, vibration readings were provided for the boiler feed pumps, combustion fans, circulating water pumps, and the STs. Vibration monitoring is also conducted for the GT units and is used to identify issues.

5.3. MAINTENANCE AND OUTAGE SCHEDULES

Sargent & Lundy requested the historical and planned maintenance and outage schedule for the Plant, which was not provided; however, recent outages included the following:

Common:

- PREPA currently has a tank inspection program, per API code and SPCC[6] compliance, planned in the next six years for all power plants. The detailed timing for San Juan was not provided.
- A fuel line inspection program is planned for all PREPA power plants in the next six years for code compliance, maintenance, and life extension; however, the detailed timing of the program for San Juan was not provided.
- Condition assessment programs for the boilers and high-energy piping are also planned in the next six years. The detailed timing of the program for San Juan was also not provided.

San Juan Unit 5:

- Repairs to the rotor and stator were completed in August 2020 due to a phase-to-phase failure.

San Juan Unit 6:

- The stator was fully rewound, and the rotor was cleaned in July 2020.

Additionally, the following information was provided about maintenance under the LTSA:

Figure 5-1 is an excerpt from Exhibit 2 of the LTSA. It was stated that for the Unit 5 GTG, the 32k turbine inspection was completed in November 2018. For the Unit 6 GTG, the 16k turbine inspection was completed in February 2018; however, MHPS inspection reports for these maintenance intervals were unavailable. The actual operating hours, equivalent operating hours, and equivalent fired hours (EFH) are currently unknown. The EFH and the effective starts (ES) referenced in Figure 5-1 have a direct impact on the maintenance schedule, and long-term future hours based on previous usage is difficult to estimate with the available data.

[6] spill prevention, control, and countermeasure

Figure 5-1 — San Juan Gas Turbine LTSA Maintenance Schedule

EXHIBIT 2

PLANNED MAINTENANCE SCHEDULE AND WORKSCOPES

E2.1 Planned Maintenance Schedule

	Planned Maintenance Inspection Number									
	1	2	3	4	5	6	7	8	9	10
Unit 5										
EFH since First Fire	8k	20k	32k	44k	56k	68k	80k	92k	104k	--
Gas Turbine	TI	CI	TI	CI	MI	CI	TI	CI	MI	
GT Generator					MI				MI	
GT Rotor			Pre-CRI		CRI					
Unit 6										
EFH since First Fire	8k	16k	28k	40k	52k	64k	76k	88k	100k	112k
Gas Turbine	CI	TI	CI	TI	CI	MI	CI	TI	CI	MI
GT Generator						MI				MI
GT Rotor				Pre-CRI		CRI				

Where:

CI	=	Combustor Inspection
TI	=	Turbine Inspection
Pre-CRI	=	Comprehensive Rotor Inspection Pre-Assessment
MI	=	Major Inspection
CRI	=	Comprehensive Rotor Inspection

The "EFH since First Fire" in the Planned Maintenance Schedule above are presented for reference purposes. Actual intervals between two consecutive Planned Maintenance Inspection of each Covered Unit will be

	First to occur of
Before first TI	8,000 EFH / 300 ES
After first TI	12,000 EFH / 450 ES

5.4. SPARE PARTS

A spares list for the facility was available for review during Sargent & Lundy's 2018 visit. Spares on site are extensive, and there are three warehouses devoted to them. Spares to note include the spare air-heater baskets, turbine nozzles, pump impellers, and capital valves. Tracking for local spares is done by hand and through the corporate asset management program.

5.5. ENERGY MANAGEMENT SYSTEM

PREPA, at the corporate level, employs numerous automated control applications to ensure the safe and reliable operation of its system. These applications coordinate with or are integrated into larger systems that support PREPA's routine technical and commercial operations. PREPA uses controls and an energy management system (EMS) to regulate the supply-side generation of electricity to match real-time electric power demand from the users.

In 2012, a supplier provided an updated EMS to replace the older system employed at the time. The 2012 system updated the generation mixture to include intermittent and renewable generation to reflect the new supply-side resources becoming available due to mandated legislation. The EMS also incorporated cybersecurity compliance with the North America Electric Reliability Council's infrastructure standards. In addition to upgrading the EMS, the supervisory control and data acquisition functionality was also updated to link the central EMS with the generation plants and substations.

6. PERFORMANCE REVIEW

To evaluate the performance of the Plant, Sargent & Lundy reviewed historical operating performance, provided by PREPA, of the units and benchmarked it against a group of industry peer units where data was available. Primary performance indicators reviewed include the following:

- Generation
- Net capacity factor (NCF)
- Equivalent availability factor (EAF)
- Equivalent forced outage rate (EFOR)
- Net heat rate

NCF is the annual net energy production as a fraction of the energy that would be produced if a plant operated at its rated capacity 100% of the time. EAF is a measure of an electric generating unit's availability, where it is a percentage of time that the unit has been available during a specified time period, including the impact of de-ratings (times when the unit is operating at a lower power output). EFOR is a measure of an electric generating unit's unreliability. It is the percentage of time that a unit is in a forced outage during a specified time period, including the impact of forced unit.

PREPA provided operation data for the past five full years of operation (2015–2019) and 2020 through July. Sargent & Lundy also reviewed data cataloged by the North American Electric Reliability Corporation (NERC) within their generating availability database system (GADS)[7] and established peer groups of units comparable to the GTs and STs of Units 5 and 6 and a separate peer group for thermal Units 7–10 to compare reliability data.

Sargent & Lundy applied the selection criteria identified in Table 6-1 to the NERC GADS database[8] to establish separate reliability peer group for the GTs and STs for Units 5 and 6, as the data was reported separately by both PREPA and NERC for combined-cycle units and for the thermal units. The resulting peer groups that reflect these unit characteristics included nine units owned by eight different operators, with the dataset including 36.92 operating years of reporting data for the STs, 353 units operated by 94

[7] NERC maintains records of reliability information for generating stations within the United States and Canada based on data provided by the station owners and operators. These data are compiled within GADS. Within the GADS, filters can be applied to review reliability data by plant characteristics, such as plant prime mover, nameplate capacity, fuel type, and age. Filters can also be applied for plant generating statistics, such as plant capacity factor. In this way, GADS can report reliability data which are reflective of a peer group of plants with specific characteristics and generating statistics. Sargent & Lundy filtered GADS to obtain reliability statistics that reflect a peer group of units similar to the San Juan units.

[8] Accessed via pc-GAR software on November 11, 2020. Version: PC-GAR v4.01.16.

utilities with 2,264.58 operating years of reporting data for the GTs, and 10 units by five owners with 73 operating years for the thermal units. Note that heat rate is not reported to NERC, and therefore peer group data is not presented in this report. Table 6-2 provides a summary of the key performance data for San Juan. Note that the peer group identified is for units operating on natural gas, to which San Juan converted in 2020 (operating on No. 2 fuel oil previously).

Table 6-1 — San Juan Units Peer Group

	San Juan Unit Characteristics			Peer Group Characteristics		
Technology	**Commercial Operation Date (COD)**	**Unit Gross Capacity (MW)**	**Operating Fuel**	**COD/Age**	**Unit Gross Capacity (MW)**	**Operating Fuel**
CC Gas Turbine	2008	168*	No. 2/Natural Gas	5–20 years	125-200	No. 2/Natural Gas
CC Steam Turbine	2008	64*	No. 2/Natural Gas	COD 2000–2020	23-125	No. 2/Natural Gas
Steam Units	1965–1968	100	HFO	COD 1960–1975 and 40-60 years	75-125	Distillate Oil or Oil

* There are variances with the Unit 5 and 6 nameplate capacities which indicate a generating capacity of 220 MW (GT of 160 MW and ST of 60 MW); Sargent & Lundy has not been able to confirm these values.

Table 6-2 — San Juan Overall Key Performance Data Summary

Key Performance Indicator	2015	2016	2017	2018	2019	2020 YTD[1]
Generation (MWh)	3,121,376	3,667,965	3,142,684	2,990,817	2,292,497	1,668,204
Equivalent Availability (%)	56.1	64.6	63.6	59.0	60.8	67.0
Net Capacity Factor (%)	42.4	49.7	42.7	40.6	35.4	44.1
Equivalent Forced Outage Rate	24.3	22.9	22.0	25.7	15.5	31.4
Net Heat Rate (Btu/kWh)[2]	9,923	9,405	9,544	8,924	8,790	10,389

1. 2020 January through July
2. Btu/kWh = British thermal unit per kilowatt hour

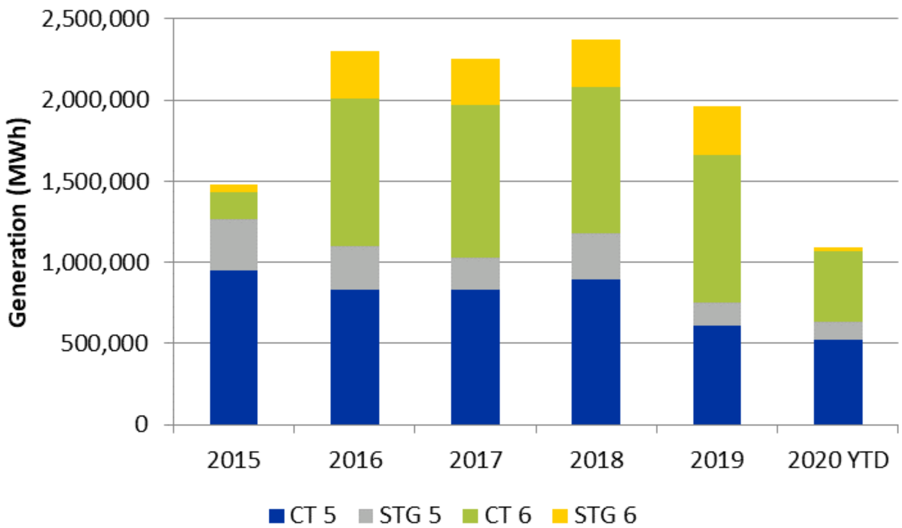
6.1. GENERATION

Generation for Units 5 and 6 is provided in Figure 6-1, while the generation of the thermal units is shown in Figure 6-2. The generation figures provide totalized information for the annual plant generation of power.

The combined-cycle units' generation and net capacity values correspond to combined-cycle units run as base load, beginning in 2016. There is a direct relationship with the GT and STG for each combined-cycle unit, and the STG portion is approximately one-third of the GT. The net capacity of the STG is slightly lower than the GT; this is reflective of cycling time inefficiencies determined from dispatch. Other factors, including system leakage and the temporary bypass of the STG for water quality concerns, also lower the output (see Section 3.1.2.1).

The base-loaded operation of the combined-cycle units indicates the importance of the units in the grid. Additionally, the relatively low heat rate and high availability in recent years contribute to the high dispatch of the San Juan combined-cycle plants. Note that the units were converted to natural gas in 2020, which is reporting only seven months of data.

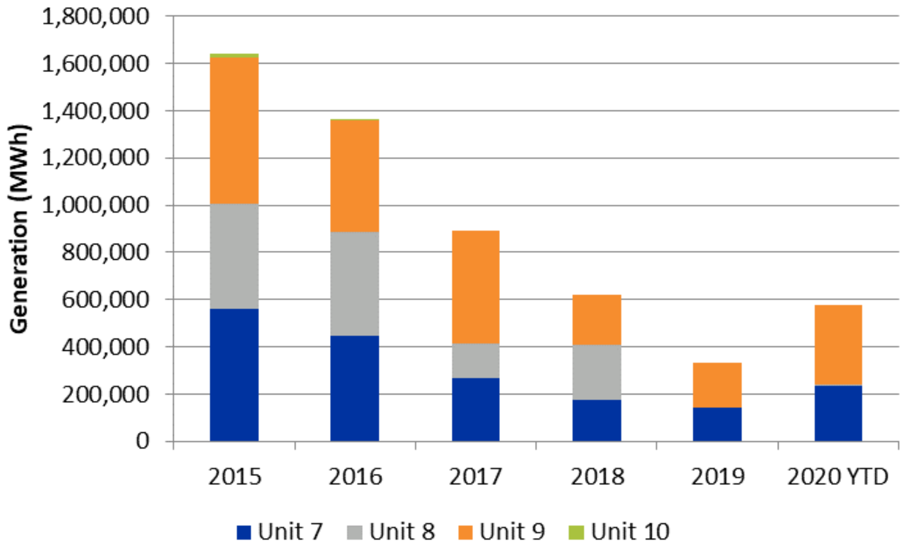
Figure 6-1 — San Juan CC Units Generation



YTD 2020 is January 1–July 30

San Juan's thermal plants consist of four oil-fired boilers and STs. Generation has fallen in recent years and can be partially explained with the lower availability of Units 7–10 and the higher availability and more dispatchable Units 5 and 6. The thermal units' base-loaded operation changed in 2016 and continued to decline through 2020. Unit 10 is in extended outage due to ST blade repair issues as discussed in Section 3.1.2.5. Unit 8 is available for emergency use only due to MATS operating limits. San Juan's thermal unit generation is provided in Figure 6-2.

Figure 6-2 — San Juan Thermal Plant Generation



YTD 2020 is January 1–July 30

6.2. AVAILABILITY FACTOR

The EAF is the fraction a facility is available to generate electricity at net dependable capacity subtracted by de-rated conditions. EAF is calculated as follows:

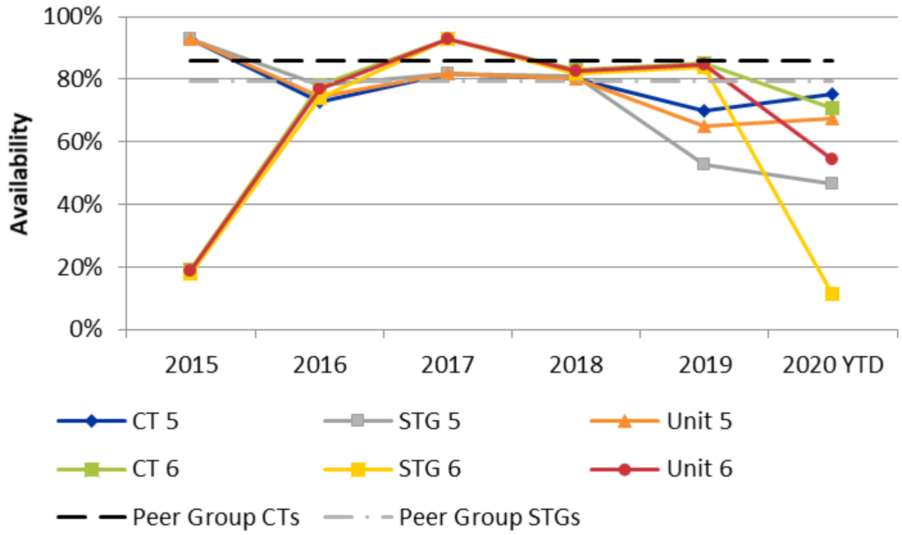
EAF = ([Available Hours - (Equivalent Unplanned De-Rated Hours + Equivalent Planned De-Rated Hours + Equivalent Seasonal De-Rated Hours)]/Period Hours) x 100

San Juan's combined-cycle EAF increased significantly after the planned outages of 2014 and 2015 and maintained a high reliability, with availability dropping in 2019 and 2020 mainly due to the planned conversion to natural gas. Barring ST problems, both the respective GT and ST track along a similar path.

San Juan's combined-cycle units have reached a high availability, topping out at 93% for both Unit 5 and Unit 6 in 2015 and in 2017, respectively. The availability is similar to the peer group. San Juan's combined-cycle unit availability is provided in Figure 6-3.

The availability for the PREPA fleet will include a deduction for the required EPA environmental maintenance outages. This significantly impacts the ratings in the system; therefore, the availability has an upper limit, and availabilities higher in other systems cannot be directly compared with the PREPA fleet.

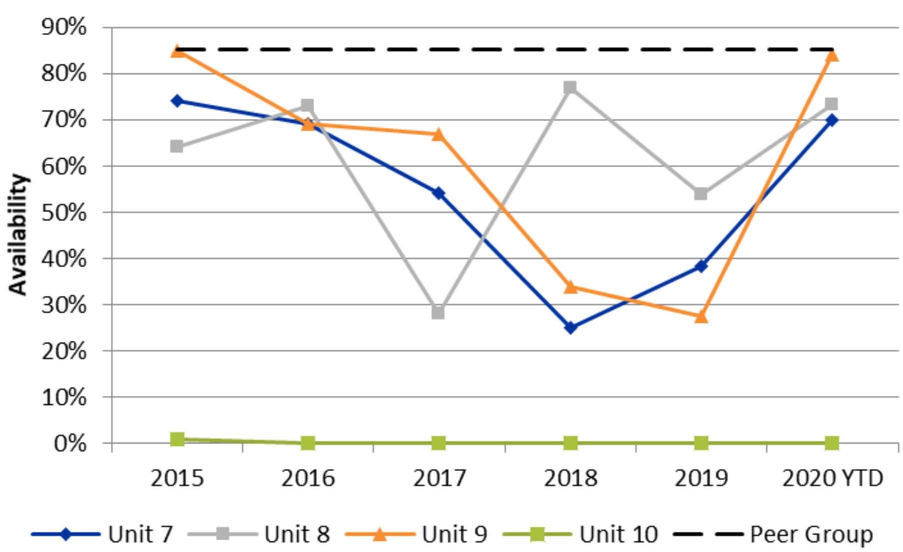
Figure 6-3 — San Juan Combined-Cycle Units' Equivalent Availability Factors



YTD 2020 is January 1–July 30

San Juan Units 7–9 provided high average availability until 2016. Due to outages, the availability declined in 2017 through 2019. Unit 8's planned outage in 2017 returned that unit to a high level of availability. The remaining maintenance work for the rest of the thermal plants is lowering the availability. San Juan's thermal plant availability factor is provided in Figure 6-4.

Figure 6-4 — San Juan Thermal Plant Equivalent Availability Factor



YTD 2020 is January 1–July 30

6.3. EQUIVALENT FORCED OUTAGE RATE

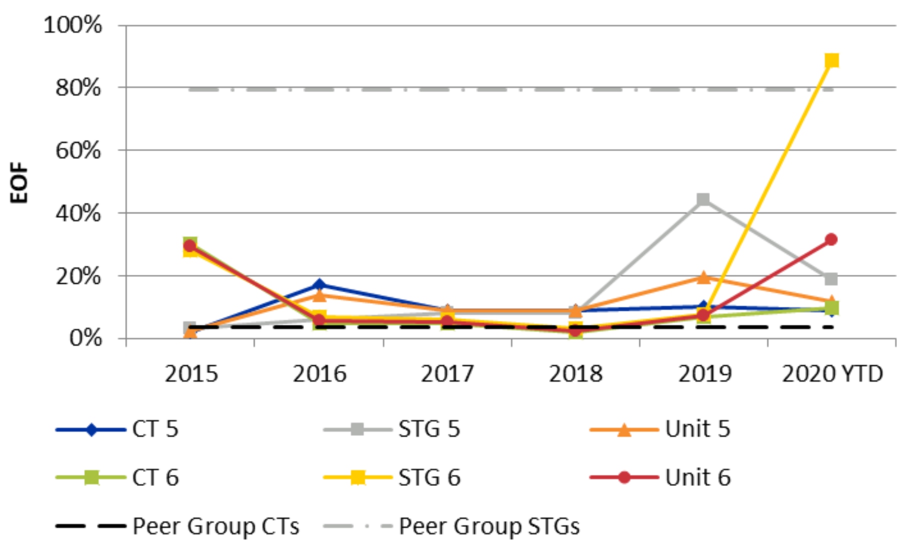
EFOR is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings, excluding planned or maintenance outages. In other words, EFOR is a rating to indicate how the unit is unable to respond, irrespective of system need.

EFOR = (Forced Outage Hours + Equivalent Forced De-Rated Hours)/(Service Hours + Forced Outage Hours + Equivalent Reserve Shutdown Forced De-Rated Hours) x 100

San Juan's combined-cycle forced outage factor is provided in Figure 6-5. Unit 6 emerged from the planned outages with a lower EFOR than Unit 5, 2% vs. 9%, respectively, in 2018. Despite the differences, both had similar net capacities in 2018, 64% and 65%, respectively; however, there are current critical pump issues as discussed in Section 3.1.2.1.

San Juan's combined-cycle units had significant planned and maintenance outages up through 2016. After 2016, the planned and maintenance outages were significantly reduced until 2019.

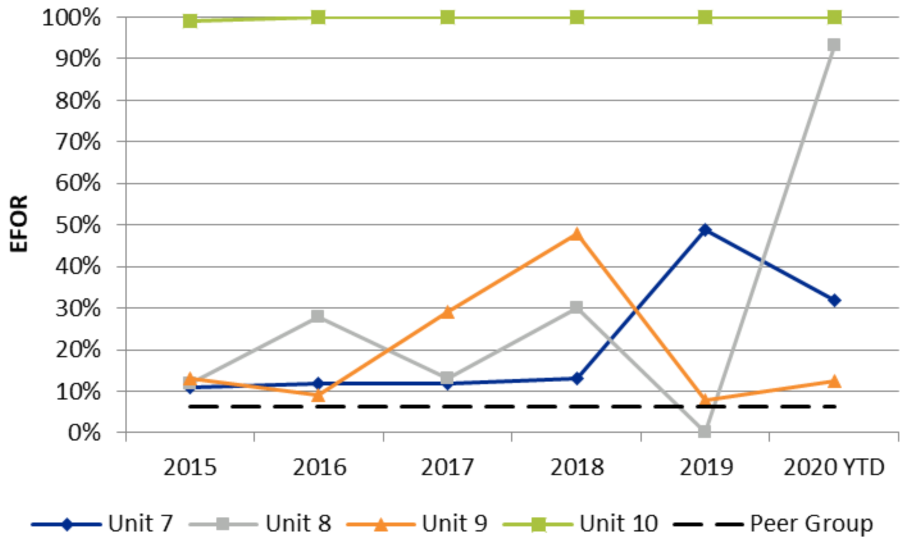
Figure 6-5 — San Juan Combined-Cycle Units' Equivalent Forced Outage Rates



YTD 2020 is January 1–July 30

The forced outage rate of San Juan's thermal plants has risen significantly for many of the units and is higher than the peer group. Unit 10 has been in a long-term outage since 2015. In 2018, Unit 9 underwent an outage, but staffing priorities shifted to a Unit 7 outage and were not refocused until 2019. As mentioned previously, the Unit 7 thermal unit had the lowest average EFOR, ranging between 9% and 13%. The EFORs for San Juan's thermal plants is provided in Figure 6-6.

Figure 6-6 — San Juan Thermal Plant Equivalent Forced Outage Rates



2020 YTD is January 1–July 30

6.4. CAPACITY FACTOR

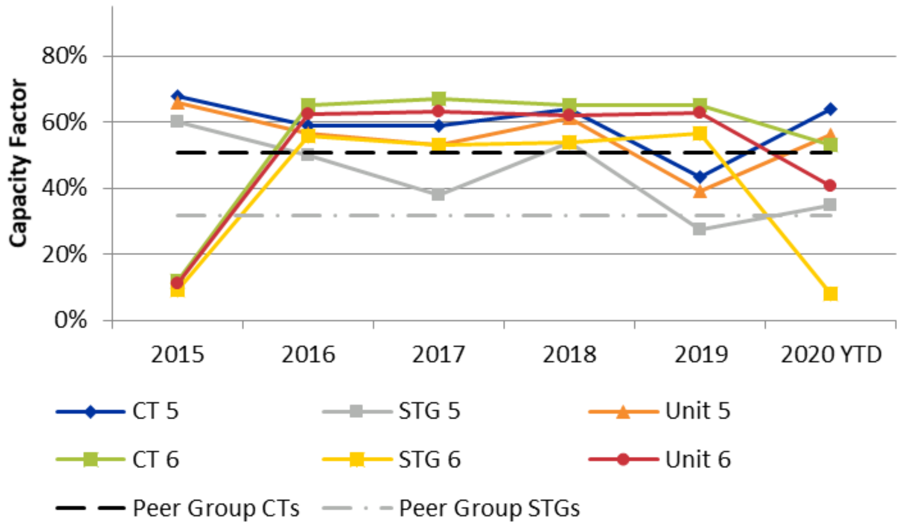
When reviewing availability and forced outage value changes, it is important to identify if the unit was being dispatched differently. In a gross fashion, the NCF provides insight into this. NCF is a percentage representing the average output of the facility during the time it was active (declared operational). The net capacity factor is calculated as follows:

NCF = (Total Net Generation/[Net Capacity at Mean Ambient Temperature x Period Hours]) x 100

As mentioned above, capacity factors increased after the planned outages of 2014 and 2015 for Unit 6. The factors are representative of base-loaded operations (i.e., high hours of use but lower capacity output). It also indicates cycling or partial load dispatch. The highest capacity factor for the GTs was Unit 5 in 2015, with a capacity factor of 68%. The low was the Unit 6 GT at 12% in 2015.

The capacity factors for GT 5 and STG 5 and GT 6 and STG 6 end up at the same percentage. Due to the known issues with the STG de-rates, this data does not reflect the operating status. A small gap between the associated GT and ST is expected until the steam-side operational issues, discussed in Section 3.1.2.1, are corrected.

Figure 6-7 — San Juan Combined-Cycle Units' Capacity Factors

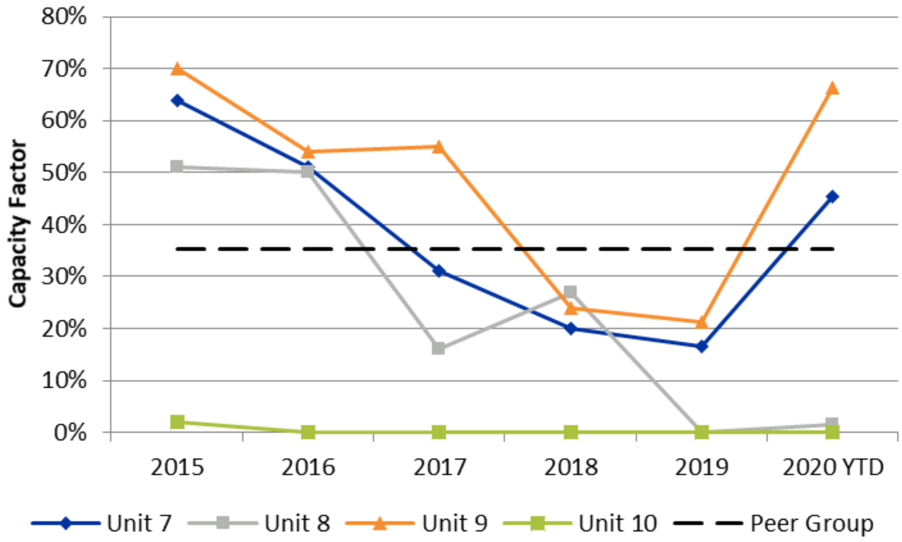


2020 YTD is January 1–July 30

The San Juan thermal units trend (total) downward after 2016. Prior to 2016, the units were base-loaded, with the exception of Unit 10. The reasons for the lower capacity include lower availability, lower dispatch, and the increased availability of Units 5 and 6.

The capacity factors for San Juan's thermal units are provided in Figure 6-8. As mentioned previously, Unit 10 has been in extended outage since 2015.

Figure 6-8 — San Juan Thermal Plant Capacity Factors



2020 YTD is January 1–July 30

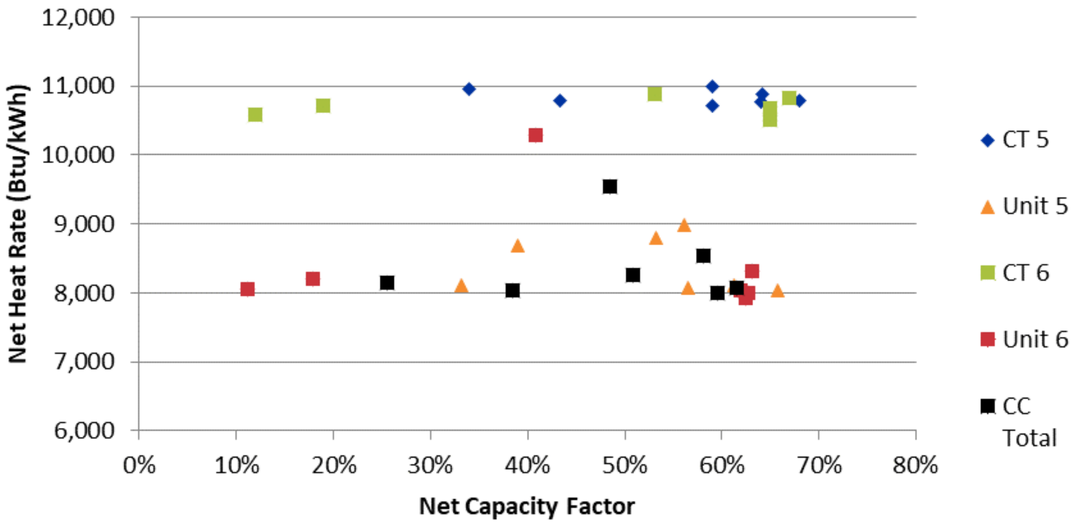
6.5. NET HEAT RATE

The heat rate is the amount of energy used by an electrical generator or power plant to generate 1 kWh of electricity. Heat rate shows, in general, the efficiency of the unit and, to an extent, represents the units to be considered in a dispatch hierarchy. The heat rate is slightly degraded through service.

Heat rate also can be used to determine the expected fuel requirements necessary for generation. As fuel represents the largest variable cost, having a lower heat rate than that of other similar units is a competitive advantage. Lower heat rates are indicative of a generating unit that is efficient at converting fuel into electricity; if two generating units of similar design and vintage are compared, the unit with the lower heat rate will have lower variable fuel costs than the other unit.

San Juan's combined-cycle units show lower heat rates in comparison to other combined cycles in the fleet; however, the rates are high in comparison to other combined-cycle units. The original heat-rate calculation indicates the combined-cycle heat rate is 6,696 Btu/kWh at full load; at partial load, the values can be significantly higher. The combined-cycle net heat rate ranges within 8,036–9,538 Btu/kWh.

Figure 6-9 — San Juan Combined-Cycle Units: Heat Rate vs. Capacity Factor



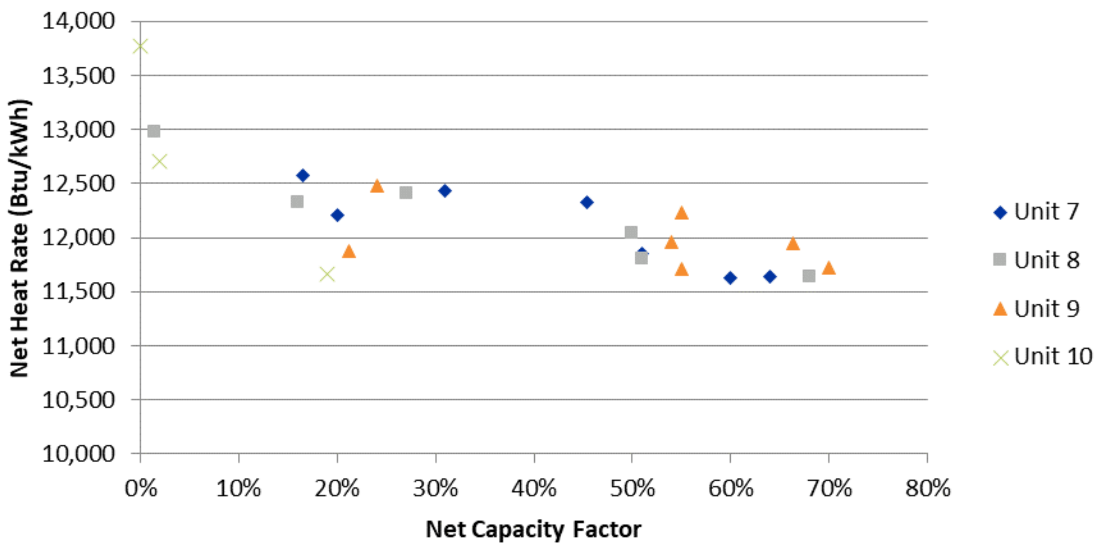
2020 YTD is January 1–July 30

Sargent & Lundy recommends PREPA evaluate the reference performance data for the San Juan combined-cycle units and compare it to the original heat rates indicated in the Plant guaranteed values. Previous recommendations in Section 3.1.2.1 regarding heat rate and efficiency indicate that steam-side issues should be evaluated and corrected.

The net heat rates for San Juan's thermal units are consistent across the three operating units. The oil-fired boiler design is similar with other boilers in the fleet. The heat rates provided are higher than other similar units within the peer group. According to the data provided by PREPA, Units 7–9 all show similar heat rates and tracked each other regardless of availability and capacity differences. Each unit tracked from 11,637 Btu/kWh (Unit 7; 2015) to a high of 12,983 Btu/kWh (Unit 8; 2020). Unit 10 shows low hours of generation (despite outages) since 2015, and a heat rate is provided for the limited run time in 2015 and 2016.

The heat rates for the San Juan thermal units are provided in Figure 6-10.

Figure 6-10 — San Juan Thermal Units: Heat Rate vs. Capacity Factor



2020 YTD is January 1–July 30

7. FINANCIAL REVIEW

Sargent & Lundy compiled the historical O&M and capital expenditures (CAPEX) for San Juan from reported PREPA data and fiscal plan forecasts for Fiscal Year (FY) 2015 through FY 2018. Data for April 2018–October 2020 was requested but had not been received by the time of publishing.

Cost data for San Juan is reported under the Generation Directorate, which is one of the five PREPA directorates (Generation, Transmission, Distribution, Customer Service, and Administrative & General). Historical O&M costs were obtained from the following data files and reports:

- *Generation O&M by RESP.xlsx*
- *Generation and Sales History.xlsx*
- *Plant Template v4.xlsx*
- *PREPA Ex 1.02 Part 1 Economic Analysis Report.pdf*
- *PREPA Ex 1.02 Part 2 Economic Analysis Report Appendices.pdf*

Historical expenditures were compiled from the following data files and fiscal plan forecasts:

- *CEPR-AH-06-12 Attach 01.xlsx*
- *Certified Fiscal Plan NME Forecast.xlsx*
- *180419 Fiscal Plan Capital Projection.xlsx*

Summaries of O&M costs and CAPEX for San Juan and comparisons with industry values are presented in the subsections below.

7.1. FIXED AND VARIABLE O&M

Fixed O&M costs are independent of the amount of the plant generating output, such as fixed labor, materials, and administrative and general costs. Variable O&M costs are directly proportional to plant generating output such as chemicals and consumables. The reported fixed and variable O&M costs for San Juan are aggregated. Also, the costs for Units 5 (200 MW) and 6 (200 MW) are combined with the San Juan Units 9 (100 MW) and 10 (100 MW). Units 7 (100 MW) and 8 (100 MW) are not included, since PREPA's reported data for FY 2017 excludes them.[9]

[9] MW capacity values shown in this report section are nominal values reported by PREPA for cost reporting and do not necessarily reflect the latest tested capacity.

Table 7-1 summarizes the historical O&M costs at San Juan, including annual MWh generation. This does not include corporate costs for the Generation Directorate that is common with other plants, such as administrative, technical support, and fuel contracting.

Table 7-1 — San Juan Historical O&M Costs (FY 2015–FY 2018)

San Juan (Steam 200 MW; Combined Cycle 400 MW) - Historical O&M Costs ($)	FY2015	FY2016	FY2017	FY2018 YTD-April
Operating Labor				
348 - Jefe Div. Central Gen. San Juan	16,618,624	15,732,639	14,831,931	11,008,261
349 - Administración de Proyectos de Conservación San Juan	-	-	-	-
Construction/Maintenance Labor				
348 - Jefe Div. Central Gen. San Juan	350,633	658,199	314,977	-
349 - Administración de Proyectos de Conservación San Juan	-	-	-	-
Operating Non-Labor				
348 - Jefe Div. Central Gen. San Juan	7,216,111	8,605,889	6,482,123	7,517,472
349 - Administración de Proyectos de Conservación San Juan	800	-	-	-
Construction/Maintenance Non-Labor				
348 - Jefe Div. Central Gen. San Juan	13,407,740	12,883,858	14,927,046	1,827,891
349 - Administración de Proyectos de Conservación San Juan	-	-	-	-
Total O&M Costs ($)	**37,593,908**	**37,880,585**	**36,556,076**	**20,353,625**
MWh	2,955,000	3,512,000	3,688,000	

FY = July 1–June 30

The aggregated O&M costs shown above correspond to the fixed and variable components estimated by PREPA in the aforementioned economic analysis report. Table 7-2 summarizes PREPA's estimate of the fixed O&M ($/kW-year) and variable O&M ($/MWh) for the San Juan combined-cycle and steam units. Sargent & Lundy compared these values with O&M costs for existing units in operation in North America of similar configurations and operating profiles and determined that the San Juan O&M costs are within the typical range of costs for similar units considering that higher O&M expenditures are required for plants firing HFO as compared to natural gas. Note that the combined-cycle units have since switched to burning natural gas.

Table 7-2 — Costa Sur Fixed and Variable O&M Cost Breakdown

	San Juan Combined-Cycle Units 5 (200 MW) and 6 (200 MW)	San Juan Steam Units 9 (100 MW) and 10 (100 MW)
Fixed O&M (2015 $)	$26.15/kW-year	$46.78/kW-year
Variable O&M (2015 $)	$2.12/MWh	$2.69/MWh

7.2. CAPITAL EXPENDITURES

Historical CAPEX expenditures reported by PREPA for San Juan for FY 2015 through FY 2018 are summarized in Table 7-3. Approximately $340,000 in CAPEX was spent in FY 2016 with no CAPEX spending in the other years. Sargent & Lundy compared these values with CAPEX for existing units in operation in North America of similar ages and configurations.[10] From the data, Sargent & Lundy determined that the annual CAPEX expenditures for San Juan are within the typical range of costs for similar units, considering that higher expenditures are required for plants firing HFO as compared to natural gas. Note that San Juan Units 5 and 6 converted to natural gas in 2020.

Table 7-3 — San Juan Historical CAPEX (FY 2015–FY 2018)

San Juan (Steam 200 MW; Combined Cycle 400 MW) - Historical CAPEX ($)	FY2015	FY2016	FY2017	FY2018
BOILER REHABILITATION				
SJ U8				
SJ U9				
SJ U10				
TURBOGENERATOR REHABILITATION				
SJ U5		44,769		
SJ U6		166,896		
SJ U8				
SJ U9				
SJ U10		1,163,280		
TURBINE REHABILITATION				
SJ U 8				
COMPONENTES DE REPUESTO (OTHER BALANCE PLANT)	368,068	532,055		
REHAB. TURBINAS VAPOR CICLO COMBINADO SJ5				
COMBINED CYCLE REHABILITATION U5 SJSP	4,231,953	6,888,767		
COMBINED CYCLE REHABILITATION U6 SJSP	3,847,487	4,551,102		
CONVERSION A GAS NATURAL U 7-10 (OBP)				
CONV DUAL FUEL TURBINAS COMBUSTION U 5-6 (OBP)				
REHABILITACION SALIDA FORZADA				
SJ U6	607,783			
SJ U10	426,790	1,018,060		
Total CAPEX ($)	**9,482,081**	**14,364,929**	**n/a**	**n/a**
$/kW-yr	15.80	23.94		

[10] "Generating Unit Annual Capital and Life Extension Costs Analysis – Final Report on Modeling Aging-Related Capital and O&M Costs," prepared by Sargent & Lundy for the US Energy Information Administration, May 2018.

8. ENVIRONMENTAL AND REGULATORY

This section describes certain environmental requirements that currently apply to San Juan and includes a limited review station's current environmental compliance status. This section does not include a review of new and proposed regulatory initiatives that may have an impact on future operations at San Juan.

San Juan operates under the key permits and approvals identified in Table 8-1. Based on review of permits and documentation provided by PREPA or publicly available information, all major environmental permits for the San Juan facility are current or in the process of being renewed.

Table 8-1 — San Juan Power Plant Key Permits and Approvals

Permit/Approval Description	ID Number	Permit Expiration Date
Title V Operating Permit	PFE-TV-4911-65-1196-0016	May 31, 2010 (renewal application has been filed; see Section 8.1)
National Pollution Discharge Elimination System (NPDES)	PR0000698	August 31, 2023
Resource Conservation and Recovery Act – Hazardous Waste	PRD980644496	N/A
Safe Drinking Water Act	N/A	N/A
Franchise for the Use of Waters of Puerto Rico	R-FA-FAID6-SJ-00165-04062013	N/A

Sargent & Lundy reviewed environmental compliance information provided by PREPA and information obtained from the EPA's ECHO[11] database to determine the current environmental status of the facility. Provided below is a review of the facility's status for following areas: air emissions, water and wastewater discharge, emergency planning reporting, oil storage spill prevention, and recent enforcement actions.

8.1. AIR EMISSIONS

The San Juan Title V Operating Permit includes emission limits and monitoring, recordkeeping, and reporting requirements for San Juan. PREPA provided Sargent & Lundy with the facility's Title V operating permit that was issued on May 31, 2005 and expired on May 31, 2010. The facility is required to submit a renewal application to the EQB[12] at least 12 months prior to the expiration date. PREPA submitted its renewal application on May 29, 2009, and on November 2, 2009 PREPA received a letter from EQB stating

[11] Enforcement and Compliance History Online
[12] Puerto Rico Environmental Quality Board

that PREPA had submitted an administratively complete renewal application in accordance with EQB regulations for the purposes of obtaining the protective cover of the permit. According to PREPA, the permit renewal is pending on EQB approval. The major emission units regulated under the 2005 Title V operating permit include the following:

- Four HFO-fired boilers with steam turbo-generators each with a capacity of 1,007.3 MMBtu/hr. (propane is used for the ignition process of the fuel burners)

In 2004, a prevention of significant deterioration (PSD) permit was issued by the EPA, authorizing the construction of two combined-cycle units at San Juan. Each unit, capable of generating 238 MW (net), includes one Westinghouse 501 distillate oil-fired combustion turbine, one HRSG, and one STG. Each combustion turbine is equipped with a steam injection system for NO_X control. The PSD permit also requires NO_X emissions reductions from the existing HFO-fired boilers by modifying burners and using good combustion control. For control of sulfur dioxide and sulfuric acid mist, the permit requires the use of only low sulfur No. 2 fuel oil in which the sulfur content may not exceed 0.05% by weight in the combustion turbines and requires the use of HFO with 0.5% fuel sulfur content at the four boilers. Additional pollutants are required to be controlled through the use of good combustion practices. The PSD permit also authorized the installation of two 2.5-MW auxiliary generators using No. 2 fuel oil, the conversion of two existing HFO storage tanks to distillate-oil storage tanks, the installation of two new fixed-roof fuel storage tanks, and the installation of six new cooling towers. The combustion turbines are required to meet the limits included in Table 8-2.

Table 8-2 — Combustion Turbine Emissions Limits

Pollutant	Limit	Averaging Period
CO	25 ppmvd@15%O_2 (base load)	3-hour rolling
	60 ppmvd@15%O_2 (between 60% and base load)	
VOC	6.2 ppmvd@15%O_2 (base load)	1-hour
	10 ppmvd@15%O_2 (between 60% and base load)	
NO_X	34.2 ppmvd@15%O_2	8-hour rolling

VOC = volatile organic compounds | CO = carbon monoxide

The facility is required to retain all required monitoring and supporting information for a period of five years. Recordkeeping and reporting requirements include the following:

- Semiannual monitoring reports/sampling
- Deviations due to emergencies
- Deviation reporting for hazardous air pollutants
- Annual emissions reports
- Annual Title V compliance certification
- Monthly or quarterly reports to provide fuel consumption and fuel sulfur content

8.1.1. Air Permit Compliance

Sargent & Lundy reviewed air compliance documents supplied by PREPA, including annual emissions reports, semiannual monitoring reports, and annual Title V compliance certifications. Sargent & Lundy also reviewed air compliance information included in EPA's ECHO database.

EPA's ECHO database does not identify any Title V permit deviations as part of the annual compliance certifications for 2014–2019. PREPA's annual emissions reports for 2013–2019 show that the San Juan's facility-wide annual emissions have been below allowable levels (see Table 8-3).

Table 8-3 — San Juan Power Plant Annual Emissions

Pollutant	Allowable Emissions (ton/yr.)	Actual Emissions (Ton/Year)						
		2013	2014	2015	2016	2017	2018	2019
PM	2,946.22	2,152.45	2,025.88	1,961.22	1,788.84	971.65	1,036.97	653.29
PM_{10}	1,430.51	992.71	890.32	916.33	952.71	615.11	690.13	500.41
SO_2	7,619.76	5,307.88	5,135.92	4,708.70	4,299.92	2,250.51	2,388.79	1,459.37
NO_X	6,739.20	4,767.38	4,355.03	4,379.27	4,345.01	2,652.87	2,932.20	2,044.11
VOC	1,654.73	1,014.42	793.29	967.63	1,311.48	1,070.46	1,265.95	1,038.31
CO	190.70	115.31	93.59	109.08	139.18	108.74	127.48	102.51
Pb	3.54	0.16	0.14	0.15	0.17	0.12	0.14	0.11

PM = particulate matter | PM_{10} = particulate matter, 10 micrometers or less | SO_2 = sulfur dioxide | VOC = volatile organic compounds | CO = carbon monoxide | Pb = lead

Sargent & Lundy reviewed annual Title V compliance certifications for 2013 and 2015–2019. PREPA did not provide Sargent & Lundy with the annual compliance certification for 2014; therefore, the 2014 compliance certification was not reviewed. There were no reported deviations from the facility's Title V permit for the years 2013 and 2015. In 2016, 2017, and 2018, PREPA reported excess emissions for opacity. The excess emissions are explained in the reports as being due to startup/shutdown, control equipment problems, process problems, and other known causes. Equipment was adjusted as needed or taken out of service. Note that during portions of 2017 and 2018, PREPA was operating under a "No Action Assurance" granted by the EPA in the aftermath of Hurricanes Irma and Maria for relief from certain Title V permit requirements, including emission limitations.

Sargent & Lundy also reviewed semiannual monitoring reports for 2017, 2018, and second half 2019. Sargent & Lundy was not provided semiannual reports for any other periods. Semiannual monitoring reports for 2017 and first half 2018 identify deviations related to opacity levels. The excess opacity emissions are explained in the reports as being due to startup/shutdown, control equipment problems, process problems, and other known causes. Equipment was adjusted as needed or taken out of service. The "No Action Assurance" granted by the EPA was effective starting October 2017 and extended through April 2018, covering portions of the second half of 2017 and the first half of 2018.

Semiannual monitoring reports for the second half 2017, first and second halves of 2018, and the 2017 Title V compliance certification were not submitted according to the normal reporting schedule. Emergency conditions related to Hurricanes Irma and Maria prevented PREPA from preparing and submitting the required reports on time; therefore, the EPA extended reporting deadlines for all reports covered under the "No Action Assurance" to May 30, 2018. According to PREPA, the EPA gave PREPA until July 30, 2018 to submit the reports, and the EQB informally extended the deadline to be consistent with the "No Action Assurance." According to PREPA, the first-half 2018 semiannual report was submitted in February 2019. In March 2019, PREPA submitted the second-half 2017 semiannual report and the 2017 and 2018 annual Title V compliance certifications.

8.1.2. Mercury and Air Toxics Standards

The four HFO-fired boilers at San Juan are subject to the MATS. The MATS compliance date was April 16, 2015, with the option for a one-year extension to April 16, 2016. PREPA submitted an extension request for San Juan, but the extension request was denied on the basis of being incomplete. In communications with the EQB, PREPA explained that they were continuing to analyze options for compliance.

Units 7 and 8 are designated as limited-use units (i.e., they are subject to a heat input limit of 8% as averaged over a 24-month block period). Limited-use units are subject to significantly less stringent requirements under MATS. While these units must comply with the tune-up work practice standard, they are not subject to emissions limits for particulate matter (PM), hydrochloric acid, hydrofluoric acid, or the startup/shutdown work practice standards. According to PREPA, Units 7 and 8 failed to meet the 8% heat input limit during the first 24-month block period (2015–2017). Units 7 and 8 also failed to meet the 8% heat input limit during the second 24-month block period (2017–2019); however, a good portion of this time period was covered by "No Action Assurance" with the EPA related to the hurricanes.

Units 9 and 10 include a PM continuous emissions monitoring system for demonstrating compliance with the MATS PM limit. Compliance with the hydrochloric acid and hydrogen fluoride limits is demonstrated based on fuel moisture content being less than 1.0%.

Sargent & Lundy reviewed MATS compliance reports for 2017–2019. That MATS compliance reports indicates that PM emissions at Unit 9 have been exceeding the MATS. Unit 10 did not operate between 2017 and 2019 and has been out of service for the majority of the time since MATS compliance started in April 2015. According to PREPA, it came online only twice in April 2015 for a few days but experienced turbine failures and was taken out of service.

8.1.3. One-Hour Sulfur Dioxide NAAQS

The Clean Air Act requires the EPA to establish National Ambient Air Quality Standards (NAAQS). Areas that do not meet the NAAQS are designated as "non-attainment areas" for that particular air pollutant, while areas meeting the NAAQS are designated as "attainment areas." NAAQS standards are established by the EPA to be protective of public health and welfare, and the EPA is required to periodically review and update the NAAQS as necessary.

The one-hour sulfur dioxide (SO_2) NAAQS was published on June 2, 2010. The Plant is located in the Municipality of San Juan, which is currently designated non-attainment for the one-hour SO_2 NAAQS. A plan will need to be developed by the EPA/EQB for bringing the area into attainment with the one-hour SO_2 NAAQS. At this time, Sargent & Lundy cannot predict what the plan will require regarding SO_2 reductions from San Juan's turbines and boilers; however, since the boilers combust HFO, it is expected that some reductions may be required. Potential options for reducing SO_2 emissions, if deemed necessary by the EPA/EQB, include firing fuels with lower sulfur content and the installation of post-combustion SO_2 controls.

8.2. WATER AND WASTEWATER DISCHARGE

Sources of wastewater from San Juan include non-contact cooling water, screen wash water, condensate water, floor and equipment drains, wastewater treatment Plant effluent, and stormwater. Wastewater is discharged to San Juan Bay via three separate outfalls. The facility's discharges are authorized under NPDES[13] Permit PR0000698. The permit's expiration date is August 23, 2023.

8.2.1. NPDES Permit Compliance

Sargent & Lundy reviewed the EPA's ECHO database to evaluate the facility's NPDES permit compliance status. The ECHO database identifies unresolved Clean Water Act violations for San Juan dating back to

[13] National Pollution Discharge Elimination System

the fourth quarter of 2015. The listed violations include ongoing exceedances for pollutants such as copper and nickel. Other listed violations are related to late and missing discharge monitoring reports (DMRs). According to PREPA, all DMRs were submitted on time. Sargent & Lundy was not provided any DMRs from 2015, 2019, and 2020 for review; however, Sargent & Lundy reviewed DMRs and addendum reports that PREPA submitted to the EPA for 2016, 2017, and 2018.

In 2016, 2017, and 2018, exceedances were reported for copper, cyanide, and nickel as related to wastewater treatment plant (WWTP) effluent. As a corrective measure, PREPA planned to install an advanced water treatment system (estimated completion date in 2019) to reuse the WWTP effluent to prevent the recurrence of the exceedances. The ECHO database indicates that effluent violations have continued through 2019 and 2020.

PREPA also reported exceedances for fecal coliforms; corrective measures included designing an enhancement of the oil-water separator system and storm water pipeline along with the implementation of the San Juan wastewater treatment improvement project (that included the water condensation recovery system that was compliance in April 2016). In 2018, PREPA reported exceedances for fecal coliforms. Corrective measures included the removal of pigeon excrement and improvements to the oil separator. PREPA also reported exceedances for copper related to WWTP effluent, and pH limit exceedances were related to a pipeline leakage related to the operational process with the RO system. In October 2018, exceedances were only reported for temperature caused by an overflow of the Unit 5 and 6 sump due to a failure of the water motor pump; an order was issued for the purchase of new pumps and motors.

8.2.2. 316(b) Cooling Water Intake Structure Requirements

On August 15, 2014, the EPA published a final rule implementing Section 316(b) of the federal Clean Water Act. The purpose of the rule is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures used by certain existing power generation and manufacturing facilities.

San Juan withdraws approximately 750 million gallons per day of seawater from San Juan Bay for once-through cooling, sea water screen washing, recirculating cooling, boiler makeup water and equipment cleaning, and maintenance. The intake structure for Units 7 and 8 has four traveling screens with an array of two screen wash pumps. The intake structure for Units 9 and 10 has four traveling screens and an array of four pumps.

The facility's current NPDES permit requires PREPA to collect and submit various information and studies related to its Section 316(b) compliance by certain dates. By six months after the effective date of the permit (September 1, 2018), PREPA was required to submit an anticipated schedule for submittals. By 48 months after the effective date of the permit, PREPA must submit a status report indicating its progress toward choosing its preferred impingement mortality standard compliance method; PREPA must also submit an entrainment characterization study by that date. By 54 months after the effective date of the permit, PREPA must either confirm that the EPA already has sufficient information concerning 316(b) compliance or submit the necessary information "related to source water physical data, cooling water intake structure data, source water baseline biological data, cooling water system data, a chosen method to comply with impingement requirements, entrainment performance studies, and operational status." Additional compliance deadlines and requirements are detailed in the permit.

8.3. EMERGENCY PLANNING REPORTING

The Emergency Planning and Community Right to Know Act (EPCRA) provides for nationwide public disclosure of emergency information to protect the public from chemical emergencies and dangers. EPCRA Section 312 (40 CFR Part 370) requires certain facilities that maintain safety data sheets to report the quantity of chemicals that are present on site for the previous year; the submittals are known as Tier 2 reports. EPCRA Section 313 (40 CFR Part 372) requires certain facilities that manufacture, process, or otherwise use listed toxic chemicals in excess of applicable thresholds to prepare and submit a toxic release inventory to federal and state agencies.

Sargent & Lundy was provided with a Tier 2 report for the reporting period from January 2017 to December 2017 which was prepared for San Juan and submitted in 2018. Based on review of the report, it appears that the facility is following the necessary reporting requirements.

EPA's ECHO database confirms that PREPA has prepared and submitted toxic release inventory reports. The records indicate that, during the period of 2009–2019, reporting requirements were generally triggered for benzo(ghi)perylene, copper compounds, lead compounds, mercury compounds, naphthalene, polycyclic aromatic compounds, and sulfuric acid.

8.4. OIL STORAGE SPILL PREVENTION

Sargent & Lundy reviewed a copy of San Juan's SPCC plan. The SPCC plan, required by 40 CFR Part 112, identifies onsite oil storage containers and provides a plan for preventing the discharge of oil into navigable waters or the adjoining shoreline. The San Juan SPCC plan follows the Part 112 requirements and appears complete.

Sargent & Lundy also reviewed correspondence related to SPCC inspections provided by PREPA. On December 4, 2014, EPA conducted a SPCC inspection at San Juan. EPA's inspection report included comments concerning tank integrity testing, the condition of Tank R-4, and a significant amount of oil under the dike liner surrounding Tank R3. On December 30, 2014, PREPA responded to the EPA, stating that tank integrity inspection reports were being revised and would determine necessary corrective actions. In addition, PREPA provided the EPA with a schedule for the cleaning and repair of Tank R-4 and planned activities associated with cleanup around Tank R3. On August 12, 2015, the EPA requested that PREPA provide an updated schedule for necessary changes or additions outlined in the December 4, 2014 inspection report. On September 17, 2015, PREPA's response to the EPA included updated schedules for tank integrity testing and cleanup around Tank R-3. PREPA also informed the EPA that work for Tank R-4 would only include roof repairs. No further correspondence was provided to Sargent & Lundy for review.

8.5. ENFORCEMENT ACTIONS

On March 19, 1999, the US District Court for the District of Puerto Rico entered a consent decree between the United States and PREPA ("1999 Consent Decree") (Civil Action No. 93-2527).

The consent decree includes detailed requirements to promote compliance with the following:

- Clean Air Act
- Clean Water Act
- Resource Conservation Recovery Act
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)
- EPCRA

Requirements for the San Juan facility included implementing a Clean Air Act compliance program, Clean Water Act compliance program, and preparing a SPCC plan, among other requirements. A consent decree modification, lodged on June 21, 2004, included additional objectives for monitoring and reducing air emissions such as opacity readings, reducing fuel sulfur content, and NO_X emission reductions.

It is Sargent & Lundy's understanding through discussion with PREPA that PREPA is generally complying with the requirements of the consent decree; however, PREPA paid stipulated penalties under the Clean Air Act and Clean Water Act's compliance programs in 2018.

8.6. SUMMARY

Sargent & Lundy performed a limited environmental review of publicly available information and information provided by PREPA to evaluate the compliance status for San Juan. Sargent & Lundy did not find any compliance-related issues that would prevent renewal of the existing permits or impact near-term operation of the facility; however, the items listed below were identified as having unknown or potential compliance implications for San Juan:

- Air Emissions
  - Unit 9 PM emissions exceed the applicable MATS standard.
  - The San Juan area is currently designated nonattainment for the one-hour SO_2 NAAQS. The EPA/EQB's forthcoming plan for bringing the area into attainment with the one-hour SO_2 NAAQS may require SO_2 reductions from San Juan.
- Water and Wastewater
  - The ECHO database and DMRs show ongoing discharge exceedances (Sargent & Lundy was not provided DMRs for December 2018 or anytime thereafter for review).

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9. RECOMMENDATIONS AND CONCLUSIONS

San Juan's total nameplate capacity is 864 MW; however, the current operating capacity is approximately 534 MW, of which 30 MW should easily be recoverable after the combined-cycle STG deratings are resolved. San Juan is a mix of older thermal plants and new combined-cycle units. Thermal Units 7–10 have provided power generation service since the 1960s but are at the end of their design life. A decline in plant performance and reliability should be expected during the operating life of a power generation plant and is evident in the case of the thermal units. Anticipated infrastructure maintenance and repair would not to be cost effective for continued service, largely due to the current extended disuse of some of the thermal equipment, extensive coastal corrosion impact across the plant and equipment, and safety concerns associated with the end-of-life operation. It is recommended that San Juan's thermal units be phased out of service and replaced by units with the capacity and flexibility as determined by a separate feasibility study and a load demand and resource study. PREPA intends to retire the steam units over the next five years.

Units 5 and 6 were converted to fire natural gas in January 2020 and April 2020, respectively, and now are considered dual-fired units (i.e., the units can fire 100% No. 2 fuel oil and 100% natural gas). As part of the dual-fuel conversion project, an SCR will be installed on HRSG 5 on November 2020 (it is currently unknown if HRSG 6 will be upgraded with an SCR). As part of the aforementioned feasibility study for replacing Units 7–10, consideration should be given to the use of natural gas to fuel new units at the San Juan site.

Since its initial siting, the Plant is—due to its proximity to the large San Juan population, the availability of seawater supply for cooling, and the nearby port services—an ideal location for power generation on the island. If new generation is contemplated, a modern design should be considered—one that uses best available technologies for improved efficiency, environmental impact, and emissions controls. The new generation units can have additional operational flexibility designed for rapid response to support shifting load demands and a greater penetration of renewable sources of power like wind and solar. Any new design or modification must include better protection and material selection than currently in place for this coastal installation as well as a hardening of the facilities to enable command and control of power production during emergency conditions, such as harsh weather events.

The existing GIS building sustained minor damage during Hurricane Maria but is suitable to house the existing 380-kV GIS equipment and the installation of new 115-kV GIS equipment. Installation of the new 115-kV GIS equipment will require some modifications of the building, such as new floor openings, to allow cable entrance to the equipment and may require localized floor reinforcement.

Future generation plans may require the installation of a new GIS building. The existing building lacks sufficient space to accommodate the additional future GIS breakers. The existing building cannot be expanded due to space constraints both for the building and transmission and generation connections. This project is currently ongoing and is expected to begin construction in by the end of 2021.

Finally, there is currently an underground sea cable, 115-kV Line 38000, that is part of a planned San Juan underground loop. The loop will connect seven stations around the San Juan area. This underground sea cable was damaged by a contractor dredging in the channel. PREPA is assessing the damage and scope to getting this repaired. The underground loop requires both Line 38000 and the San Juan 115-kV GIS be energized to take full advantage of the loop.

As evident in the current plans to fire the combined-cycle Units 5 and 6 with natural gas, there are aspects of San Juan that are suitable for upgrades and improvements so that it may continue operations and power production. Sargent & Lundy found Units 5 and 6 in acceptable operating condition. Both units could be evaluated for potential GT upgrades. Sargent & Lundy noted 15-MW de-ratings on each of the combined-cycle STGs and recommends addressing the deratings to regain this loss in power output and efficiency. Resolution of the de-ratings is required for the units to operate a full capacity. Sargent & Lundy recommends that an independent third party conduct a full root-cause analysis and provide recommendations and an action plan to bring closure to the issue. Once corrected, there should be no issue with the combined-cycle facility reaching its full electrical output and design heat rate.

Care must be taken to ensure that replacements or upgrades to the Plant are suitable for an aggressive, salt-laden marine environment exposed to coastal winds. Typically, competitively priced OEM standards for power generation and balance-of-plant equipment are not suited for this type of operating environment. New equipment must be configured for the challenging conditions at San Juan. Failure to make allowances for suitable materials, equipment selection, buildings/enclosures, and other aspects of the facility design to protect the Plant from operating environment will result in excessive future O&M costs and a shorter plant design life for any new installation. Suitable design specifications appropriate for this operating environment include corrosion-resistant material specifications, appropriate welding selections—including special treatment of all metal seams, stitched connections, and fastenings with sealants, gaskets, and coatings—use of protective equipment enclosures, proper system selections, and marine coating systems. Due to these requirements, coastal power generation sites are inherently more expensive than those installed in less aggressive operating environments.

PREPA continues to evaluate the need for additional grid support and generation throughout Puerto Rico. Smaller, rapid-start GT equipment can be easily adapted to integrate purge credit, battery storage for instantaneous response, and other similar features to provide a quicker response for a future grid that is planned to integrate a larger amount of renewable power. Generators from Units 7–10 may be evaluated for use in synchronous condensing operations. Given the age of the Plant, Sargent & Lundy anticipates that only the generators may be suitable and that all balance-of-plant equipment would require replacement to ensure reliable service. A phased-in approach for equipment replacement can be considered. This can be implemented with the use of temporary mobile turbine generator units while the Plant is reconfigured.

Ongoing proposals for Plant replacements, upgrades, and new generation should consider the guidelines provided herein. New operating regimes and other comparisons must be made so that equipment is selected to suit the future direction of the power generation and distribution system planned for Puerto Rico.

Smaller, rapid-start GT equipment with integrated synchronous condensing options could be planned for reclaimed space at San Juan. As mentioned, new fast-start generation equipment that integrates purge credit, battery storage components for instantaneous response, integrated/clutched synchronous condensing, and similar features could provide quicker support and flexibility for a future grid that is planned to integrate a larger amount of less stable renewable power. Reciprocating engine plants provide even faster startups than GT equipment and can be configured to operate on natural gas and in combined-cycle configurations and provide black-start capability to GT equipment.

The Unit 5 and 6 GT units have multiple upgrade possibilities to consider, including improvement of heat rate and power. Driven by the power generation market conditions, Siemens has also integrated features into their GT designs that permit fast startups and restarts. Sargent & Lundy recommends that the upgrades are evaluated based on market analysis and feasibility. Upgrades to the GTs will also require condition and capability assessments of the HRSG, ST, and balance-of-plant equipment if higher steam flows, pressures, temperatures, electrical output can be produced, especially HRSG HP and high-temperature parts.

The following recommendations should be considered for each of the significant systems. The recommendations are given in the anticipation that a similar generation plant of equivalent nameplate electrical output would be provided and maintained at the site.

- The raw water system capacity, and the final water treatment system (including RO and demineralizer) solution, should be evaluated for similar capacity, either higher or lower, for the site. Cycling and plant design will need to be identified for overall water requirements. Individual tank areas will need to be assessed for potential reuse with new generation layouts. Two demineralized water tanks and two raw water tanks were installed with the addition of Units 5 and 6 and should be included when considering the footprint for the new Plant design.
- The fire protection system will need to be evaluated for a potentially larger flow rate. Most units in comparable sites have a minimum 2,000–2,500 gpm electric and No. 2 fuel oil pumps separated by a firewall and a corresponding two-hour storage tank capacity. The design of the ST underfloor protection system will typically govern the maximum water flow rate, on which the final

recommendation for larger equipment will be dependent. The underground system should be evaluated for life extension prior to modification. The potential of liquefied natural gas on or adjacent to the site is also to be evaluated for the fire protection requirements.

- Sargent & Lundy recommends that the Unit 5 and 6 intake and discharges be evaluated for either a tie-in with the Unit 9 and 10 intake, which is separated from the discharges by a small jetty, or a possible upgrade to a different cooling method such as a cooling tower with lower water requirements. For a cooling tower makeup arrangement, the redesign can take advantage of the intake location without using the older concrete structures and tunnels throughout the Plant. If cold water discharge is available from the floating storage and regasification unit, discharge into the Unit 5 and 6 intake or other uses can be evaluated.
- The new water treatment system, when complete, should be assessed for use with potential new units. The capacity should be sufficient for a similarly sized combined cycle; however, if new peaker units with demineralized water injection are used, the storage and instantaneous capacity should also be evaluated.

The addition of an auxiliary boiler should be evaluated for startup of Units 5 and 6 and for any foreseeable future units. The evaluation should consider unit dispatch and response times for anticipated load and generation required.

10. REFERENCES

1. Sargent & Lundy report, “San Juan Phase I Environmental Site Assessment,” SL-014468.SJ.ESA, dated May 30, 2019.
2. Sargent & Lundy report, “Demarcation of PREPA Generation Assets from the Transmission and Distribution System,” TD-0003, dated October 4, 2019.
3. Fuel sale and purchase agreement between NFENERGIA LLC and PREPA, dated March 5, 2019.