Aguirre Site Economic Analysis

Puerto Rico Electric Power Authority (PREPA)

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Section

1

Executive Summary

This “Aguirre Site Economic Analysis” proceeding involves a defined economic analysis of the Aguirre Offshore Gas Port (AOGP) and the Aguirre site in relation to the Integrated Resource Plan (IRP) submitted to the Puerto Rico Energy Commission (PREC or Commission) by the Puerto Rico Electric Power Authority (PREPA), a public power electric utility. In the underlying IRP proceeding before the Commission, PREPA with the assistance of Siemens Industry, Inc., Siemens Power Technologies International (Siemens PTI) and Pace Global, a Siemens business (Pace Global) (collectively referred to as Siemens) prepared and filed the original draft of its proposed IRP, consisting of five volumes (Volumes I to V) on July 2015. The Commission issued a Notice of Deficiencies regarding the original IRP on August 3, 2015. PREPA, to comply with the Commission’s Notice, filed updated versions of Volumes I to IV on August 17, 2015, and of Volume V on September 30, 2015. The original IRP as revised in 2015 is referred to as the “Base IRP”. The Base IRP, among other things, presented and supported PREPA’s proposal to complete AOGP and the conversion to natural gas firing of the Aguirre generating units.

On December 4, 2015 the Commission issued an order directing PREPA to amend and supplement the Base IRP to include additional scenarios, which comprised provisions of Demand Side Management (DSM): Energy Efficiency (EE) and Demand Response, Renewable Portfolio Standard (RPS) compliance, and to evaluate scenarios with and without AOGP, AES and EcoEléctrica. In order to comply with those directives, PREPA and Siemens prepared a Supplemental Integrated Resource Plan (Supplemental IRP) and ran eleven scenarios with and without the AOGP. The Supplemental IRP (also known as the “Fuel IRP” or the “Updated Fuel IRP”) was submitted in final form in April 2016.

As a result of its evaluation of the material submitted by PREPA, intervenors, and members of the public, on September 26, 2016, the Commission issued a Final Resolution and Order. As part of its determination, the Commission ordered PREPA to submit “a detailed economic assessment of the AOGP project, assessing a range of fuel forecasts, demand requirements, and alternative mechanisms of meeting MATS in timely fashion”.

Following its Final Order and Resolution, on February 10, 2017, the Commission declined to change its decision on this subject in the IRP case and issued an Order requiring PREPA to conduct the AOGP’s detailed economic analysis and provided guidelines to perform the evaluation in this separate Aguirre case.

The guidelines dictated by the Commission required examining four different resource plans under a range of fuel prices scenarios and an updated load forecast to evaluate the plan for the Aguirre site. PREPA’s recommended plan for the Aguirre site again comprises the construction and operation of AOGP and the conversion to natural gas firing of the Aguirre generating units. The evaluation includes the PROMOD IV® runs of the four (4) resource plans in a twenty (20) year study period (Fiscal Years 2018-2037 beginning in July 1, 2017 and ending in June 30, 2037).

These resource plans were selected by the Commission from the Supplemental IRP report. Each plan is evaluated under three (3) different fuel scenarios (Reference, High Oil and Low Oil).

1.1 Factors Considered

PREPA used PROMOD IV® to run the scenarios indicated by the Commission. These scenarios consider the following new or revised factors.

1. The load forecast was updated as directed by the Commission. The energy sales are lower than in the forecast used in the Supplemental IRP due to a more pessimistic view of the economic and fiscal situation in Puerto Rico. Also, as in the Supplemental IRP, beginning in 2017, Demand Side Management (DSM) Energy Efficiency (EE) achieves a reduction on the modeled load, starting from 0.2 percent rate of reduction and incrementing by 0.2 percent per annum through 2024, and from 2025 and thereafter the reduction on the modeled load stabilizes at 1.5 percent per year. The EE framework assumes a cost of 4.5 cents per kWh[1] and that the load shape for EE is identical to the overall aggregate load requirement for PREPA.

2. The level of utility scale renewable generation projects were the same as considered for the Supplemental IRP.

3. PREPA followed the same methodology used by Siemens PTI in the Supplemental IRP to calculate the demand response levels. In such case, Siemens PTI evaluated the demand response necessary to achieve low curtailment[2] with full target renewable portfolio standard (RPS) compliance. The required demand response could be managed through shifting demand from the night-peak to the mid-day to increase the ability to integrate renewables. This analysis helps to quantify the amount of demand response needed.

4. PREPA updated the fuel prices and prepared three (3) scenarios as required by the Commission's order. These scenarios were based in the Annual Energy Outlook 2017 prepared by the Energy Information Administration (EIA) for a reference case, a low oil case, and a high oil case. The variables used for these projections are:

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[1] In 2014 dollars.

[2] Renewable generation curtailment happens when a portion of the renewable generation cannot be accepted due to technical requirements of the conventional generating fleet, and the renewable plant must lower its production although the solar or wind generation is available. Curtailment has a financial impact to PREPA as per the existing contractual conditions if energy production capability is available given the meteorological conditions and PREPA cannot take it. In these instances, PREPA has to pay for the estimated amount of energy that could have been produced at the contractual prices. A target of two percent curtailment has generally been agreed with PREPA.

Distillate Fuel Oil, Residual Fuel Oil, and Steam Coal for the Electric Power Sector in the United States and Henry Hub (HH).

5. PREPA updated the AOGP and new generation alternatives schedules to consider the required licensing and the construction periods.

6. PREPA updated the PROMOD IV® model considering a new load forecast, three (3) fuel price forecasts, programmed and environmental maintenance schedules, renewable energy projects integration dates and new generation alternatives commissioning dates, among others.

All other important factors remain identical to the Supplemental IRP. The objective of this evaluation is to analyze the economic viability of the AOGP considering the regulatory and economic conditions; existing and new generation resources characteristics; and the evaluation criteria dictated by the Commission.

1.2 Scenarios Evaluated

In compliance with the Commission's order, the following Scenarios (resource plans) were considered for this evaluation:

- AG – Updated Portfolio 3 Modified Future 1 Modified (P3MF1M) prepared in the Supplemental IRP. It considers the gas conversions at Aguirre and the AOGP construction.

- AG+RE – Updated Portfolio 3 Modified Future 1 Modified Sensitivity 4 (P3MF1M_S4) prepared in the Supplemental IRP. It considers the gas conversions at Aguirre and the AOGP construction, but also full RPS compliance and Demand Response following the methodology developed by Siemens.

- NO – Updated Portfolio 3 Modified Future 2 Modified (P3MF2M) prepared in the Supplemental IRP. It excludes the gas conversions at Aguirre and the AOGP construction.

- NO+RE - This is a new portfolio similar to P3MF2M, but includes full RPS compliance and Demand Response following the methodology developed by Siemens.

These cases are based on the Supplemental IRP, which provided an assessment of a modified Portfolio 3 based on a modified Future 1 (base case with AOGP) and Future 2 (a case assuming that AOGP does not happen). Portfolio 3 includes the addition of generation capacity from renewable resources, as well as new and efficient fossil fuel resources to replace existing aged and inflexible generation units to improve system efficiency and better integrate increasing renewable resources.

The availability of capital, practical licensing, and EPC (engineering, procurement, and construction) development schedules and strategies dictate the sequencing and timing of new generating units. The start date considered in the Base IRP and the Supplemental IRP was July 2015. An updated start date of January 2018 was assumed for this analysis. Due to the abovementioned time constraints, the commissioning of the new generation alternatives shifted from both the Base and the Supplemental IRP's. AOGP is scheduled to be constructed and in operation by April 1, 2019. Accordingly, the operation with natural gas of the converted Aguirre Steam units and Aguirre Combined Cycle units was rescheduled to April 2019.

Some of the schedule updates considered are the following:

- The repowering of the Aguirre CC units delayed two years and is assumed to be operational by July 1, 2022.
- In the "AG" scenarios, the new SCC-800 (or similar competing model) combined cycle unit at Palo Seco Power Plant begins commercial operation in January 1, 2023.
- In the "NO" scenarios, the commissioning dates of the new H-Class (or similar competing model) combined cycles are delayed. The new H-Class (or similar competing model) combined cycles at Palo Seco and Aguirre power plants begin commercial operation in January 1, 2024, while the H-Class (or similar competing model) combined cycle at Costa Sur power plant begins commercial operation in January 1, 2025. The Aguirre steam units' retirement was delayed until December 31, 2023.

The amount of new renewable resources to be integrated was dictated by RPS goals (at either reduced or full compliance levels) and the reduced demand is due to a more pessimistic view of the prevailing economic situation and to the EE referenced above. The renewable energy projects commissioning dates considered in the Supplemental IRP were updated for this analysis based on their current status. Some of these projects began commercial operation since then, and were considered in the PROMOD IV® runs. Those projects whose commissioning dates have not been achieved to date were delayed by three (3) years in consideration of a more representative simulation.

No additional transmission studies, other than those carried out for the implementation of the recommendations of the Supplemental IRP and presented in the report named "PREPA Integrated Resource Plan Supplementary Evaluation: Transmission Analysis" were performed as part of this analysis. However, the schedule and the capital costs associated with transmission system upgrades were updated.

The following Section presents a summary of the evaluated scenarios.

1.2.1 Summary of Scenarios

The modified IRP scenarios considered in this economic evaluation are presented in Table 1-1.

Table 1-1: Summary of Scenarios Considered in the Analysis

Scenario		Resource Plan	Fuel Plan	Fuel Price Forecast
1	AG_Base	Updated P3MF1M	AOGP	Base
2	AG_High_Oil	Updated P3MF1M	AOGP	High Oil

Scenario		Resource Plan	Fuel Plan	Fuel Price Forecast
3	AG_Low_Oil	Updated P3MF1M	AOGP	Low Oil
4	AG+RE_Base	P3MF1M_S4 Full RPS and Demand Response	AOGP	Base
5	AG+RE_High_Oil	P3MF1M_S4 Full RPS and Demand Response	AOGP	High Oil
6	AG+RE_Low_Oil	P3MF1M_S4 Full RPS and Demand Response	AOGP	Low Oil
7	NO_Base	Updated P3MF2M	No gas	Base
8	NO_High_Oil	Updated P3MF2M	No gas	High Oil
9	NO_Low_Oil	Updated P3MF2M	No gas	Low Oil
10	NO+RE_Base	P3MF2M_Full RPS and Demand Response	No gas	Base
11	NO+RE_High_Oil	P3MF2M_Full RPS and Demand Response	No gas	High Oil
12	NO+RE_Low_Oil	P3MF2M_Full RPS and Demand Response	No gas	Low Oil

1.2.2 Economic Analysis

The economic analysis considers present value of system costs. The system costs include amortized capital costs, fuel costs, variable and fixed generation operating costs, purchased power costs from AES and EcoEléctrica, renewable purchased power costs and energy efficiency and demand response costs. Capital costs considered in the evaluation include those associated with construction of new generation, conversion of existing units to use natural gas, cost of demolition of existing generation, fuel infrastructure, and transmission upgrades and improvements. The system costs also include current EPA Statutory Maximum Civil Penalties rates associated with MATS non-compliance. The system costs are not intended to capture all costs, but only those costs that have a considerable impact on the portfolios on an incremental basis.

Table 1-2 presents the system costs summary for the scenarios evaluated.

Table 1-2: System Costs Summary

System Costs	Unit	Future 1 - AOGP					
		AG_Base	AG_High_Oil	AG_Low_Oil	AG+RE_Base	AG+RE_High_Oil	AG+RE_Low_Oil
Total Present Value of System Costs	$ 000	27,966,466	32,229,507	26,035,505	29,650,010	32,450,987	26,925,712
Average Annual System Costs	$ 000	2,649,347	2,928,039	2,481,667	2,736,924	2,955,521	2,544,515

System Costs	Unit	Future 2 - No AOGP - No gas					
		NO_Base	NO_High_Oil	NO_Low_Oil	NO+RE_Base	NO+RE_High_Oil	NO+RE_Low_Oil
Total Present Value of System Costs	$ 000	31,383,572	43,279,669	24,316,491	31,953,470	42,930,765	25,272,220
Average Annual System Costs	$ 000	2,952,589	4,054,170	2,328,100	2,998,661	4,012,819	2,397,073

Section
2

Conclusions and Recommendations

Based on the assumptions used for the Economic Analysis, the key findings include the following:

1. Compared with the NO_Base scenario, the AG_Base demonstrates the benefits of AOGP. Even though NO_Base has lower capital costs, AG_Base has lower overall system costs on the order of $3.42 billion due to higher fuel costs incurred without AOGP. The forecasted Fuel Oil No. 6 average prices, are similar to current prices for the short term, and remain lower than $60/BBL until 2019, when they begin to grow gradually. The average short term price forecasted for Fuel Oil No. 2 is $93/BBL. In the twenty year forecasted period, average prices are in the order of $110/BBL for Fuel Oil No. 6 and $147/BBL for Fuel Oil No. 2. The fuel prices reach values of $182/BBL at the end of the study period for Fuel Oil No. 6 and of about $214/BBL for Fuel Oil No. 2. The conditions assumed in the base scenarios use the reference case assumptions which represent the most likely to occur.
2. Demand response with full RPS compliance scenarios AG+RE for base, high oil and low oil cases, to achieve reduced curtailment resulted in higher system costs. That is primarily due to two reasons: 1) the cheaper conventional generation is replaced by PV generation, which has a higher price; and (2) an estimated cost of 2 cents per kWh for the control systems to shift from the night peak to the mid-day.
3. The present value of the system costs in NO_High_Oil is about $11.05 billion higher than the corresponding value for the case that the AOGP is built AG_High_Oil case, thus resulting in a tremendous economic advantage of the AOGP project in case world oil prices raise to considerably higher values. In the High Oil fuel forecast, average prices are in the order of $240/BBL for Fuel Oil No. 6 and $295/BBL for Fuel Oil No. 2 in the twenty year forecasted period. The fuel prices reach values of $350/BBL of the study period for Fuel Oil No. 6 and of over $400/BBL for Fuel Oil No. 2.
4. When comparing the present value of the system costs for NO_Low_Oil Scenario with the corresponding value for AG_Low_Oil, the costs for the NO_Low_Oil scenario are about $1.72 billion lower. In the Low Oil fuel forecast world oil prices fall significantly and remain low during the twenty year study period. The average price for Fuel Oil No. 6 is $30/BBL and at the end of the study period is

still lower than $38/BBL. The average price for Fuel Oil No. 2 is $67/BBL and the price is below $93/BBL at the end of the twenty year forecasted period.

5. The comparison of the base scenario, AG+RE_Base, for the case that the AOGP is built, with the base case where there is no AOGP and no gas, NO+RE_Base, results in an economic benefit of $2.3 billion for the AOGP project.
6. The present value of the system costs of NO+RE_High_Oil scenario is about $10.5 billion higher than the corresponding value for the case that the AOGP is built (AG+RE_High_Oil case), thus resulting in a tremendous economic advantage of the AOGP project in case world oil prices raise to considerably higher values.
7. When comparing the present value of the system costs for NO+RE_Low_Oil Scenario with the corresponding value for AG+RE_Low_Oil, NO+RE_Low_Oil costs are approximately $1.65 billion lower. In this scenario world oil prices fall significantly and remain low during the twenty year study period. The average price for Fuel Oil No. 6 is $30/BBL and at the end of the study period is still lower than $38/BBL. The average price for Fuel Oil No. 2 is $67/BBL and the price is below $93/BBL at the end of the twenty year forecasted period.
8. NO+RE_Base and NO+RE_Low_Oil scenarios resulted in higher total value of system costs than the corresponding NO scenarios, but NO+RE_High Oil scenario resulted in lower total present value of system costs than NO_High_Oil scenario. The reasons for higher costs in NO+RE_Base and NO+RE_Low_Oil are: (1) the cheaper conventional generation is replaced by PV generation which has a higher price; and (2) an estimated cost of 2 cents per kWh for the control systems to shift from the night peak to the mid-day. In the NO+RE_High Oil scenario, the cost of the renewable generation becomes lower than the cost of conventional generation.
9. The AG_Base considering a one year delay in AOGP case has a present value of system cost of approximately $186 million higher than the AG_Base case, but it is still cheaper than the NO_Base case (without AOGP) by a difference of more than $ 3.2 billion dollars.
10. The results of this evaluation show that, even with a one year delay, having AOGP in operation is more beneficial for the people of Puerto Rico than terminating the project and constructing new combined cycles that would burn light distillate as fuel.
11. The results obtained show that if the Commission disapproves the AOGP Project (conversions of Aguirre boilers 1&2 and Combined Cycle units, as well as the AOGP construction), PREPA will be exposed to unnecessary and additional civil penalties due to the delays forecasted in MATS compliance for the Aguirre, San Juan and Palo Seco generating units. Based on the economic analysis results, such additional penalties will accrue to $317,059,000.
12. The results of the economic analysis demonstrated that it is economically feasible to achieve environmental compliance, provide environmental justice, and electricity price stabilization that will help to improve Puerto Rico's economic situation.

13. It is recommended to fully approve and proceed with AOGP and the associated conversions in the least time possible, in order to comply with MATS, avoid the liability to fines and proceed with the most advantageous option possible for the people of Puerto Rico, due to the demonstrated savings over the most probable outcomes.

Section

3

Demand Forecast and Energy Efficiency

3.1 Demand Forecast Methodology

The methodology used by PREPA to develop its demand and energy forecasts consist in obtaining mathematical models with statistical/econometric tools and using them to develop forecast series of energy sales for the residential, commercial, and industrial customers. An econometric model is a set of equations designed to provide a quantitative explanation of the behavior of economic variables using time series data and statistical probabilities to estimate the performance of a dependent variable.

Usually in our studies, the energy consumption by kilowatt hour (kWh) or dependent variable has a correlation with the main measures of the local economy. PREPA utilizes several sources for obtaining projections of the relevant macroeconomic variables. For this evaluation, PREPA considered the following: Gross National Product (GNP), Gross Domestic Product (GDP) and Disposable Personal Income (DPI). These sources are three independent economic consultants: Advance Business Consulting, Inc. (ABC); the Inter-American University – IHS Global Insight (IAU-GI); and the Commonwealth of Puerto Rico's Planning Board (Planning Board).

PREPA selected the latest econometric model from ABC (October 2016), which showed an annual growth rate of 0.15% from fiscal year 2017 through 2022. The following table shows the forecast economic indicators used, in millions of dollars:

Table 3-1: Economic Indicators used for Energy and Demand Forecast

Fiscal Year	GNP	DPI	GDP
2016	6,237.0	9,433.4	10,313.7
2017	6,074.0	9,188.2	10,117.8
2018	6,014.0	9,096.3	10,057.1
2019	5,978.0	9,041.7	10,137.5
2020	5,984.0	9,050.7	10,224.7
2021	6,014.0	9,096.0	10,325.9
2022	6,050.0	9,150.6	10,439.5

3.1.1 Models selected by Service Class through FY 2022

3.1.1.1 Residential:

The following figure summarizes the results of the selected model for residential customers.

Figure 3-1: Selected Model for Residential Class:

Dependent Variable: LOG(RKWH)
Method: Least Squares
Date: 03/03/17 Time: 10:37
Sample (adjusted): 1984 2017
Included observations: 34 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.123619	0.234553	0.527039	0.6020
LOG(PRM)	-0.104195	0.021713	-4.798851	0.0000
LOG(YPD)	0.344415	0.104865	3.284362	0.0026
LOG(RKWH(-1))	0.663491	0.109657	6.050608	0.0000

R-squared	0.985628	Mean dependent var	8.636699
Adjusted R-squared	0.984191	S.D. dependent var	0.236258
S.E. of regression	0.029705	Akaike info criterion	-4.084842
Sum squared resid	0.026472	Schwarz criterion	-3.905270
Log likelihood	73.44232	Hannan-Quinn criter.	-4.023603
F-statistic	685.8162	Durbin-Watson stat	2.467122
Prob(F-statistic)	0.000000		

The following variables were used for the residential class model:

i. RKWH: Residential consumption
ii. RKWH(-1): Residential consumption last year (lagging)
iii. YPD: Disposable Personal Income (DPI)
iv. PRM: ¢/kWh residential class

3.1.1.2 Commercial

The following figure summarizes the results of the selected model for commercial customers.

Figure 3-2: Selected Model for Commercial Class:

Dependent Variable: LOG(CKWH)
Method: Least Squares
Date: 03/03/17 Time: 14:18
Sample (adjusted): 1984 2017
Included observations: 34 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.330218	0.220806	-1.495515	0.1449
LOG(PBI)	0.340722	0.074061	4.600555	0.0001
LOG(CKWH(-1))	0.687184	0.054450	12.62038	0.0000

R-squared	0.996723	Mean dependent var	8.763915
Adjusted R-squared	0.996512	S.D. dependent var	0.339136
S.E. of regression	0.020030	Akaike info criterion	-4.899082
Sum squared resid	0.012437	Schwarz criterion	-4.764403
Log likelihood	86.28439	Hannan-Quinn criter.	-4.853152
F-statistic	4714.631	Durbin-Watson stat	2.147500
Prob(F-statistic)	0.000000		

The following variables were used for the commercial class model:

i. CKWH: Commercial consumption
ii. CKWH(-1): Commercial consumption last year (lagging)
iii. PBI: Domestic Gross Product (GDP)
iv. PCM: ¢/kWh commercial class

3.1.1.3 Industrial

The following figure summarizes the results of the selected model for industrial customers.

Figure 3-3: Selected Model for Industrial Class:

Dependent Variable: LOG(IKWH)
Method: Least Squares
Date: 03/03/17 Time: 15:43
Sample (adjusted): 2000 2017
Included observations: 18 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-5.193540	1.972777	-2.632604	0.0197
LOG(GNP)	0.974549	0.288125	3.382385	0.0045
LOG(IKWH(-1))	0.636531	0.083299	7.641509	0.0000
LOG(PIM(-1))	-0.169935	0.026349	-6.449317	0.0000

R-squared	0.991481	Mean dependent var	8.129915
Adjusted R-squared	0.989655	S.D. dependent var	0.250335
S.E. of regression	0.025461	Akaike info criterion	-4.310177
Sum squared resid	0.009076	Schwarz criterion	-4.112316
Log likelihood	42.79159	Hannan-Quinn criter.	-4.282894
F-statistic	543.1138	Durbin-Watson stat	1.876878
Prob(F-statistic)	0.000000		

The following variables were used for the industrial class model:

i. IKWH: Industrial consumption
ii. IKWH(-1): Commercial consumption last year (lagging)
iii. GNP: National Gross Product
iv. PIM: ¢/kWh industrial class

3.1.1.4 Long Range Projection

PREPA forecasted the energy gross production beginning in FY 2023 and through 2037 with the following selected model, where MNCAP is the net metering capacity and SQRTIM a dummy variable of time:

Figure 3-4: Selected Model for Energy Forecast:

Dependent Variable: LOG(GENE)
Method: Least Squares
Date: 03/08/17 Time: 08:19
Sample (adjusted): 2011 2022
Included observations: 12 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LOG(MNCAP)	-0.007448	0.003093	-2.407728	0.0394
LOG(SQRTIM)	-0.213970	0.020219	-10.58268	0.0000
C	11.53127	0.113147	101.9139	0.0000

R-squared	0.992014	Mean dependent var	9.938415
Adjusted R-squared	0.990239	S.D. dependent var	0.054860
S.E. of regression	0.005420	Akaike info criterion	-7.385124
Sum squared resid	0.000264	Schwarz criterion	-7.263898
Log likelihood	47.31075	Hannan-Quinn criter.	-7.430007
F-statistic	558.9847	Durbin-Watson stat	2.193195
Prob(F-statistic)	0.000000		

3.2 Energy Efficiency

The estimated energy reduction resulting from the energy efficiency program implementation was considered for the demand forecast. Beginning in 2017, Demand Side Management (DSM) Energy Efficiency (EE) achieves a reduction on the modeled load starting from 0.2 percent rate of reduction and incrementing by 0.2 percent each year through 2024, and from 2025 and thereafter the rate of reduction stabilizes at 1.5 percent per year. The energy efficiency was assumed at a cost of 4.5 cents per kWh for EE, using the dollar value for 2014, and the load shape of EE was assumed identical to the overall aggregate load requirement for PREPA. The EE cost was applied to the EE MWhs and added to the overall system costs. Table 3-2 and Table 3-3 show the modified demand and sales with the above mentioned EE included.

Table 3-2: Modified Demand Forecast with Energy Efficiency

			Peak Demand (MW)			Energy (GWh) - Generation		
Fiscal Year	Yearly Reduction	Factor	Original	New	Delta	Original	New	Delta
2016	0	100%	3,030	3,030	0	20,900	20,900	0
2017	0.20%	100%	3,080	3,074	6	20,456	20,415	41
2018	0.40%	99%	2,963	2,945	18	19,673	19,555	118
2019	0.60%	99%	2,899	2,864	35	19,243	19,013	230
2020	0.80%	98%	2,844	2,788	56	18,876	18,501	375
2021	1.00%	97%	2,804	2,721	83	18,611	18,059	552
2022	1.20%	96%	2,780	2,665	115	18,444	17,683	762
2023	1.40%	95%	2,776	2,624	152	18,423	17,415	1,008
2024	1.50%	93%	2,773	2,582	191	18,402	17,134	1,268
2025	1.50%	92%	2,770	2,540	230	18,382	16,858	1,523
2026	1.50%	90%	2,767	2,499	267	18,362	16,588	1,774
2027	1.50%	89%	2,764	2,459	304	18,343	16,322	2,021
2028	1.50%	88%	2,761	2,420	341	18,324	16,060	2,263
2029	1.50%	86%	2,758	2,381	377	18,305	15,803	2,502
2030	1.50%	85%	2,755	2,342	412	18,287	15,551	2,736
2031	1.50%	84%	2,752	2,305	447	18,269	15,303	2,967
2032	1.50%	83%	2,749	2,268	481	18,252	15,059	3,193
2033	1.50%	81%	2,746	2,231	514	18,235	14,819	3,416
2034	1.50%	80%	2,743	2,195	547	18,218	14,584	3,635
2035	1.50%	79%	2,741	2,161	580	18,202	14,352	3,850
2036	1.50%	78%	2,739	2,127	612	18,186	14,124	4,062
2037	1.50%	77%	2,737	2,094	643	18,170	13,900	4,270

Table 3-3: Modified Sales Forecast with Energy Efficiency

Fiscal Year	Energy (GWh) - Sales Original	Factor	New	Delta
2016	17,349	0.83	17,349.07	0.00
2017	17,189	0.84	17,155.02	34.38
2018	16,531	0.84	16,431.71	99.05
2019	16,170	0.84	15,976.20	193.32
2020	15,861	0.84	15,546.10	315.01
2021	15,638	0.84	15,174.59	463.86
2022	15,499	0.84	14,858.59	640.19
2023	15,481	0.84	14,633.57	847.23
2024	15,463	0.84	14,397.76	1,065.52
2025	15,446	0.84	14,166.12	1,280.07
2026	15,430	0.84	13,938.58	1,490.96
2027	15,413	0.84	13,715.03	1,698.24
2028	15,397	0.84	13,495.36	1,902.00
2029	15,382	0.84	13,279.48	2,102.30
2030	15,367	0.84	13,067.32	2,299.21
2031	15,352	0.84	12,858.84	2,492.81
2032	15,337	0.84	12,653.93	2,683.14
2033	15,323	0.84	12,452.52	2,870.27
2034	15,309	0.84	12,254.50	3,054.26
2035	15,295	0.84	12,059.84	3,235.17
2036	15,282	0.84	11,868.47	3,413.06
2037	15,268	0.84	11,680.34	3,587.98

Section
4

Renewable Generation

Given the assumed levels of energy efficiency (EE) and the corresponding reduction in demand, the required levels of renewable generation to achieve full target RPS compliance are reduced, making this more feasible, particularly after the bulk of PREPA's fleet is replaced.

As in the Supplemental IRP, RPS compliance was modeled with reduced targets for the base cases until new flexible combined cycle plants are in service and full RPS compliance is sought so that by 2035 there is 20 percent of renewable penetration. Table 4-1 below shows path used in the study.

Table 4-1: RPS Targets Modeled

Year	RPS Target	Note
2017	*8.50%*	Reduced Target
2018	*9.00%*	Reduced Target
2019	*9.70%*	Reduced Target
2020	*10.00%*	Reduced Target
2021	*10.40%*	Reduced Target
2022	*10.80%*	Reduced Target
2023	*11.20%*	Reduced Target
2024	*11.60%*	Reduced Target
2025	*12.00%*	Reduced Target
2026	*12.30%*	Reduced Target
2027	*12.60%*	Reduced Target
2028	*12.90%*	Reduced Target
2029	*13.20%*	Reduced Target
2030	*13.50%*	Reduced Target
2031	*14.80%*	Original Target
2032	*16.10%*	Original Target
2033	*17.40%*	Original Target
2034	*18.70%*	Original Target
2035	*20.00%*	Original Target

Given that the required amounts of renewable generation are a function of the sales, Table 3-3 shows the assumed generation and sales projection as affected by EE. Based on the above and the conservative assumption that DG does not count for RPS compliance (as explained in prior cases, this follows from the current legal status), the following tables (Table 4-2 to Table 4-4)[3] show the amounts of renewable generation considered for the model.

Table 4-2: Renewable Generation in 2020 for 10 Percent Penetration

Peak Generation Total (MW)	2,721
Energy Sales + Net Metering (MWh)	15,436,191
Energy DG (XXMW) @ 21% Capacity Factor	261,622
Net Sales (MWh)	15,174,569
Target Penetration	10%
Target PPOA Energy (MWh)	1,517,457
Capacity in PPOA PV + Wind (MW) in Projects	784
Total PPOA (MW)	784
Average Capacity Factor	22%
DG in the System (MW)	143
Total Renewable Generation (MW)	927
PPOA Renewable Energy Generation (MWh)	1,578,709
Total % Energy from Renewable PPOA	10%

Table 4-3: Renewable Generation in 2035 for 20 Percent Penetration

Peak Generation Total (MW)	2,127
Energy Sales + Net Metering (MWh)	12,462,255
Energy DG (XXMW) @ 21% Capacity Factor	593,723
Net Sales (MWh)	11,868,532
Target Penetration	20%
Target PPOA Energy (MWh)	2,373,706
Capacity in PPOA PV + Wind (MW) in Projects	1271
Total PPOA (MW)	1271
Average Capacity Factor	21%
DG in the System (MW)	326
Total Renewable Generation (MW)	1597
PPOA Renewable Energy Generation (MWh)	2,517,233
Total % Energy from Renewable PPOA	21%

[3] The information shown in these tables is given according to the RPS target requirement established per calendar year. The peak demand and energy (generation and sales) shown in Section 3 tables are provided per fiscal year.

For full target RPS compliance, fifteen (15) percent penetration is required in 2020 and it will be necessary to add flexibility to the electrical system. However, there are practical limitations on how soon this can be achieved, even if capital availability is not considered. The amounts of renewable generation modeled for 2020 are as shown in Table 4-4. Note that the total PPOA renewable generation required (1,228 MW) for 15 percent penetration, is very close to the value that would achieve 20 percent penetration by 2035 (1,271 MW). Therefore, increases on PPOA from this moment onwards should be small and the RPS goals achieved by the reduction in load that Energy Efficiency is expected to produce.

Table 4-4: Renewable Generation in 2020 for 15 percent penetration

Peak Generation Total (MW)	2,721
Energy Sales + Net Metering (MWh)	15,436,190
Energy DG (XXMW) @ 21% Capacity Factor	261,620
Net Sales (MWh)	15,174,570
Target Penetration	15%
Target PPOA Energy (MWh)	2,276,186
Capacity in PPOA PV + Wind (MW) in Projects	1228
Total PPOA (MW)	1228
Average Capacity Factor	21%
DG in the System (MW)	143
Total Renewable Generation (MW)	1371
PPOA Renewable Energy Generation (MWh)	2,488,499
Total % Energy from Renewable PPOA	16%

The renewable generation projects were represented using the same models employed for the Base and Supplemental IRPs, turning on or off particular projects to achieve the targets levels of penetration above.

In particular, for the maximum penetration of 20 percent renewable generation, all individual projects modeled in the Base IRP (1,056.4 MW) will be required[4], plus 215 MW of generic PV. It is important to note that the 1,056.4 MW in renewable energy is derived from currently active power purchase operating agreements (PPOA), Master Agreements, and/or contracts that were signed by PREPA. Table 4-5, lists the explicit renewable projects considered in the Supplemental IRP, which details the contract numbers. The projects in Table 4-5 were modeled in the Supplemental IRP, as PREPA had appropriate information on them, but this does not mean that these are the only currently active contracts.

[4] See, IRP Volume I dated August 17, 2015, Table 4-2: PPOA Projects Considered in this Study (p. 4-3).

Table 4-5: Renewable Projects Considered

No.	Name	Technology	Capacity (MW)	Capacity Factor (percent)	Cumulative RPS Level (percent)	Price ($/MWh)	Contract Number
1	AES Ilumina, LLC	PV	20	21	0.2	194	2010-P00050
31	Pattern Santa Isabel, LLC	Wind	95	38	2.1	157	2010-P00047
32	Punta Lima (Go Green PR)	Wind	26	28	2.5	156	2010-AI0001
46	San Fermín Solar Farm, LLC (Coquí Power, LLC)	PV	20	21	2.8	185	2011-P00050
60	Windmar Renewable Energy, Inc. (Cantera Martinó)	PV	2.1	21	2.8	197	2012-P00015
18	Horizon Energy, Inc. (Salinas Solar Farm)	PV	10	21	2.9	178	2011-P00034
24	Landfill Gas Technologies of Fajardo, LLC	Landfill Gas	4	80	3.1	100	2013-P00044
25	Landfill Gas Technologies of Fajardo, LLC (Toa Baja)	Landfill Gas	4	80	3.2	100	2013-P00073
30	Oriana Energy LLC (Yarotek, LLC)	PV	50	20	3.8	180	2011-P00048
62	Windmar Renewable Energy, Inc. (Vista Alegre)	PV	10	21	3.9	185	2012-P00052
7	Fonroche Energy, LLC	PV	40	21	4.3	175	2012-P00031
3	PV Project # 3	PV	20	21	4.6	163	2012-P00037
4	PV Project # 4	PV	57	21	5.2	172	2011-P00043
5	PV Project # 5	PV	20	21	5.4	160	2013-P00070
15	PV Project # 15	PV	20	21	5.6	165	2013-P00042
16	PV Project # 16	PV	17.8	21	5.8	171	2011-P00042
21	PV Project # 21	PV	33.5	20	6.2	167	2012-P00053
36	PV Project # 36	PV	20	21	6.4	185	2012-P00045
39	PV Project # 39	PV	20	21	6.6	170	2012-P00061
42	PV Project # 42	PV	20	21	6.9	170	2013-P00003
43	PV Project # 43	PV	20	21	7.1	158	2013-P00041
47	PV Project # 47	PV	25	19	7.3	163	2012-P00146
48	PV Project # 48	PV	20	21	7.6	158	2013-P00052
57	PV Project # 57	PV	20	21	7.8	165	2012-P00080
63	PV Project # 63	PV	20	20	8.0	185	2013-P00049
8	PV Project # 8	PV	10	21	8.1	185	2013-P00046
9	PV Project # 9	PV	30	21	8.5	185	2013-P00045
10	PV Project # 10	PV	15	21	8.6	185	2013-P00048
11	PV Project # 11	PV	30	21	9.0	185	2013-P00047
12	PV Project # 12	PV	15	21	9.1	185	2013-P00050
17	PV Project # 17	PV	30	21	9.5	185	2013-P00074
22	PV Project # 22	PV	40	21	9.9	185	2012-P00140
23	PV Project # 23	PV	20	21	10.1	185	2012-P00138
27	PV Project # 27	PV	52	21	10.7	185	2012-P00141
28	PV Project # 28	PV	20	21	10.9	185	2013-P00068
34	PV Project # 34	PV	20	21	11.2	185	2013-P00076
35	PV Project # 35	PV	20	21	11.4	185	2013-P00075
41	PV Project # 41	PV	20	21	11.6	185	2013-P00069
44	PV Project # 44	PV	20	20	11.8	185	2013-P00004
45	PV Project # 45	PV	20	21	12.0	185	2013-P00072
53	PV Project # 53	PV	30	21	12.4	185	2012-P00139
54	PV Project # 54	PV	30	21	12.7	185	2011-P00090
56	PV Project # 56	PV	20	21	12.9	185	2012-P00079
		TOTAL	**1,056.4**				

4.1 Distributed Generation

Distributed Generation (DG), *i.e.* customer installed generation is modeled as in the Base IRP, as equivalent generators located in selected substations in PREPA's network. The substations for modeling the equivalent DG were selected based on the current location of DG in the island and the customer base that will likely install this type of generation. As can be observed in Table 4-6, based on an estimate for June 2018, the bulk of the DG is located in the north of the island, which is also the expected location of a significant percentage of the load.

Table 4-6: DG Capacity by Area (MW)

Totals	Percent	MW	Note
North	71 percent	80.15	S. Juan, Bayamón, Carolina, Caguas & Arecibo
South	14 percent	16.16	Ponce
West	14 percent	15.96	Mayagüez
Total	100 percent	112.27	

The total amount of DG generation modeled was derived from PREPA's projection of DG to be added to the network starting from an initial value of 68 MW by 2015 growing to 322 MW by 2035.

Table 4-7 shows the total amounts of distributed generation modeled, the substation where the various equivalents were located, and their size.

Table 4-7: Base DG Forecast (MW) for Selected Dates and Allocations by Substation[5]

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

All DG was assumed to be photovoltaic (PV) and the production by each of the seven locations above was derived based on the expected irradiance at the sites in a similar way that the production for utility scale PV was modeled. In summary, DG is modeled by seven equivalent PV generators across the island and increasing in size.

[5]Base DG Forecast (MW) for Selected Dates and Allocations by Substation included in Integrated Resource Plan Volume I: Supply Portfolios and Futures Analysis, dated August 17, 2015 (p 4-8).

Section
5

Demand Response

Demand response (DR), *i.e.*, the shift of demand from the night peak to the mid-day to increase the capability to incorporate renewables in this instance, was assessed. In the Supplemental IRP evaluation, the demand response was designed so that the curtailment was limited to two percent and it was optimized each year to reflect the increasing capability of PREPA's fleet to accommodate renewable generation.

Renewable generation curtailment happens when a portion of renewable generation cannot be accepted in the system due to certain technical requirements of the conventional generating fleet and the renewable plant must lower its production, although sun irradiation or wind is available. Curtailment could have a financial impact to PREPA as per the existing contractual conditions, if energy production capability is available given the meteorological conditions and PREPA cannot take it. In these instances, PREPA has to pay for the estimated amount of energy that could have been produced at the contractual prices.

The levels of demand response vary by year. Table 5-1 and Table 5-2 below show the levels of renewable generation considered and the daytime curtailment that is expected under the AG+RE scenario and the NO+RE scenario respectively, for full target RPS compliance.

Although the original target was two (2) percent for daytime curtailment, the night curtailment resulted in high values, and higher values of daytime curtailment had to be allowed in order to achieve lower night time curtailment. Some years, especially early in the study period when the current fleet has not been replaced, the level of load required to be moved from the night to the day to comply with the two percent target of daytime curtailment was considerable. The night time demand resulted in values below the minimum operating levels of the units, which caused high values of thermal unit curtailment. The night time curtailment is due to conventional generation limitations, which to some extent could be handled using the minimum non-regulating limits of the generators. Lowering the thermal units to their emergency lower limits, their capability to regulate is lost and the operation could be challenging. This is not feasible during daytime with PV generation online as regulation is a paramount consideration for the safe operation of the system.

Note that as the fleet modernizes the level of curtailment drops. This is followed in the tables by the required ***average level*** of demand response by year. This is a selected value so that when multiplied by the shape of the demand response (see below) the curtailment is limited to a design value of mainly 2 percent[6].

[6] The actual obtained curtailment was higher than this target, possibly due to additional restrictions on regulating reserve that necessitated having more thermal units online than

Note that in the AG+RE scenario, as can be observed in Table 5-1, an average DR Level in the 380 MW range is required until year 2026 when Costa Sur units are replaced and new combined cycle begins operation. Then DR levels are reduced to values in the range of 200 MW, with a few years exception from 2030 to 2033, when even lower levels of demand response are required. In that period Aguirre units are retired and a new combined cycle begins operation.

In the NO+RE scenario, as can be observed in Table 5-2, the required average DR Level is in the 400 MW range until year 2023 when the replacement of the Aguirre units is completed, after which it is reduced to values in the range from 100 to 200 MW.

The last column of the tables shows the estimated daytime curtailment with the demand response in place. This last value is an approximation used for the design.

those considered in the design. This finding is further supported by the fact that the “night” or thermal curtailment increased significantly, i.e., the need to bring thermal units to their emergency lower limits due to low demand.

Table 5-1: Demand Response Level for AG+RE

Calendar Year	Renewable Generation MWh	Total Curtailment MWh	Daytime Curtailment MWh (1)	Main Curtailment MWh (2)	Peak Average Curtailment MW*	Day Curtailment %	Demand Response Level MW (3)	New Day Curtailment MWh	New Daytime Curtailment %
2017	946,643	12,924	7,976	3,496	2.4	0.8%	0.0	7,976	1%
2018	1,777,193	175,938	158,898	112,510	76.6	8.9%	380.0	35,912	2%
2019	2,599,153	452,262	425,422	309,746	209.6	16.4%	380.0	102,537	4%
2020	2,739,426	613,059	590,901	442,155	290.4	21.6%	380.0	139,372	5%
2021	2,763,740	671,866	647,386	486,147	321.8	23.4%	380.0	148,566	5%
2022	2,791,202	877,906	829,534	608,522	392.6	29.7%	350.0	252,541	9%
2023	2,818,750	550,431	538,120	417,141	283.9	19.1%	380.0	88,709	3%
2024	2,848,525	686,413	666,595	507,223	334.6	23.4%	380.0	141,823	5%
2025	2,869,365	804,184	769,500	579,658	379.9	26.8%	380.0	188,094	7%
2026	2,893,866	537,817	516,954	405,118	277.3	17.9%	380.0	95,017	3%
2027	2,917,294	298,288	294,869	242,077	175.0	10.1%	200.0	75,106	3%
2028	2,944,885	292,974	289,255	240,225	174.3	9.8%	210.0	64,347	2%
2029	2,963,578	285,557	279,741	232,203	173.7	9.4%	200.0	64,334	2%
2030	2,985,035	196,225	194,231	155,324	120.0	6.5%	140.0	63,601	2%
2031	3,007,786	144,979	143,386	117,322	97.9	4.8%	75.0	61,282	2%
2032	3,035,132	156,956	155,025	127,239	99.1	5.1%	75.0	69,245	2%
2033	3,052,946	208,656	205,626	164,671	129.2	6.7%	140.0	63,218	2%
2034	3,075,745	350,143	348,097	291,732	208.3	11.3%	240.0	63,562	2%
2035	3,097,796	405,012	399,726	330,623	232.3	12.9%	260.0	64,885	2%
2036	3,124,978	401,276	396,961	325,693	223.9	12.7%	260.0	67,532	2%
2037	1,601,261	244,326	240,858	192,620	275.1	15.0%	280.0	33,110	2%

Notes

(1) Day Time Curtailment = Curtailment from 7 AM to 7 PM

(2) Main Curtailment = Curtailment from 9 AM to 3 PM used to provide a first indication on when DR should occur.

(3) Demand Response Level = the average value of the required demand response. This value x Demand Response Shape = Demand Response in MW.

Table 5-2: Demand Response Level for NO+RE

Calendar Year	Renewable Generation MWh	Total Curtailment MWh	Daytime Curtailment MWh (1)	Main Curtailment MWh (2)	Peak Average Curtailment MW*	Day Curtailment %	Demand Response Level MW (3)	New Day Curtailment MWh	New Daytime Curtailment %
2017	946,643	18,945	10,052	4,658	3.1	1.1%	0.0	10,052	1%
2018	1,777,193	261,688	229,756	158,235	105.6	12.9%	400.0	52,829	3%
2019	2,599,153	582,236	558,651	404,866	269.1	21.5%	400.0	131,044	5%
2020	2,739,426	754,829	717,982	528,077	345.5	26.2%	400.0	169,277	6%
2021	2,763,740	852,559	810,279	599,390	388.6	29.3%	400.0	199,696	7%
2022	2,791,202	825,873	767,707	566,302	370.3	27.5%	400.0	207,490	7%
2023	2,818,750	940,644	895,089	661,105	425.8	31.8%	400.0	253,036	9%
2024	2,848,525	165,507	163,600	138,289	110.1	5.7%	140.0	57,550	2%
2025	2,869,365	233,502	230,948	192,156	143.3	8.0%	230.0	58,695	2%
2026	2,893,866	142,620	140,288	123,388	100.1	4.8%	100.0	59,157	2%
2027	2,917,294	153,625	150,639	133,360	106.5	5.2%	100.0	60,977	2%
2028	2,944,885	199,235	196,333	172,020	131.0	6.7%	140.0	63,146	2%
2029	2,963,578	207,114	205,453	177,597	137.7	6.9%	140.0	63,802	2%
2030	2,985,035	259,729	257,963	220,045	166.2	8.6%	190.0	61,652	2%
2031	3,007,786	278,422	274,980	234,559	179.4	9.1%	200.0	61,123	2%
2032	3,035,132	253,397	249,409	209,676	155.6	8.2%	170.0	63,606	2%
2033	3,052,946	209,268	207,522	171,881	130.0	6.8%	120.0	64,400	2%
2034	3,075,745	221,629	218,462	176,839	134.9	7.1%	130.0	63,477	2%
2035	3,097,796	236,124	232,189	189,051	136.3	7.5%	140.0	66,208	2%
2036	3,124,978	247,842	245,448	200,885	146.3	7.9%	140.0	66,952	2%
2037	1,601,261	138,684	136,207	108,673	169.7	8.5%	160.0	33,810	2%

Notes

(1) Day Time Curtailment = Curtailment from 7 AM to 7 PM
(2) Main Curtailment = Curtailment from 9 AM to 3 PM used to provide a first indication on when DR should occur.
(3) Demand Response Level = the average value of the required demand response. This value x Demand Response Shape = Demand Response in MW.

To complement the average DR level, the shape was determined so that the response approximately matched the shape of the curtailment and the demand response contribution maximum was close to noon time and reduces towards the hours of the morning and evening.

The average DR level times the shape produces the DR for each year, as indicated above. The figures below show as a reference, the demand before and after the modeled response for year 2025 and various day types (maximum, average and minimum demand days). The actual demand response is also provided.

Figure 5-1: Maximum Demand Day

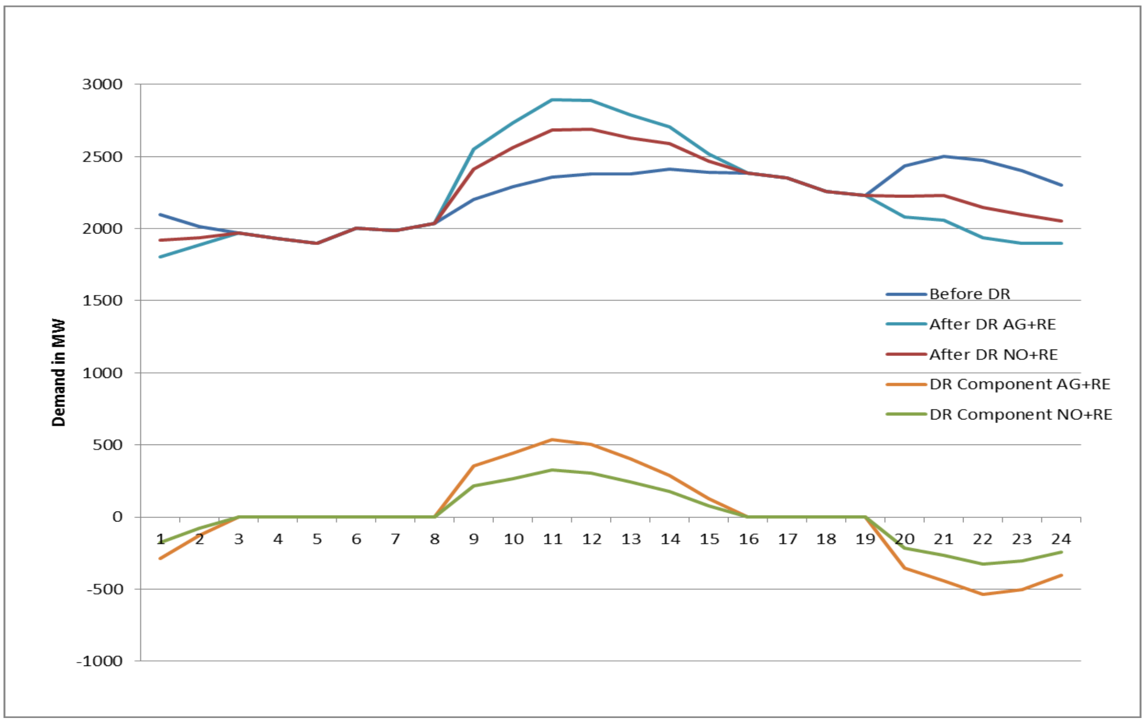


Figure 5-2: Average Demand Day

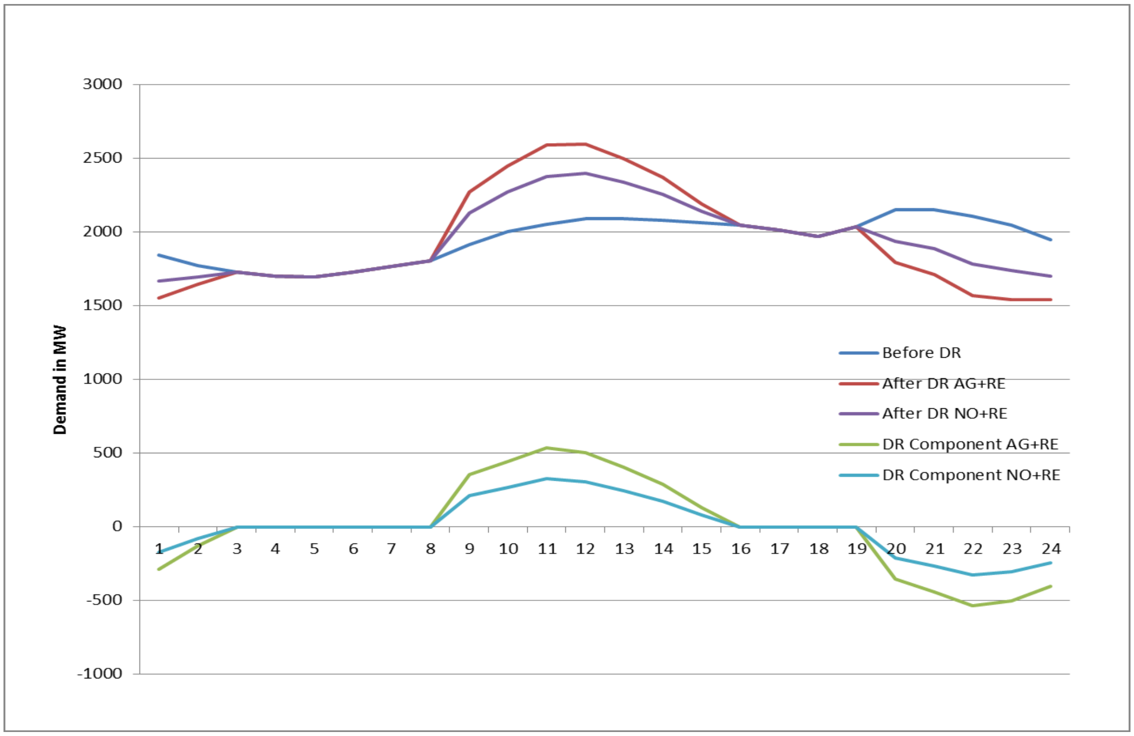
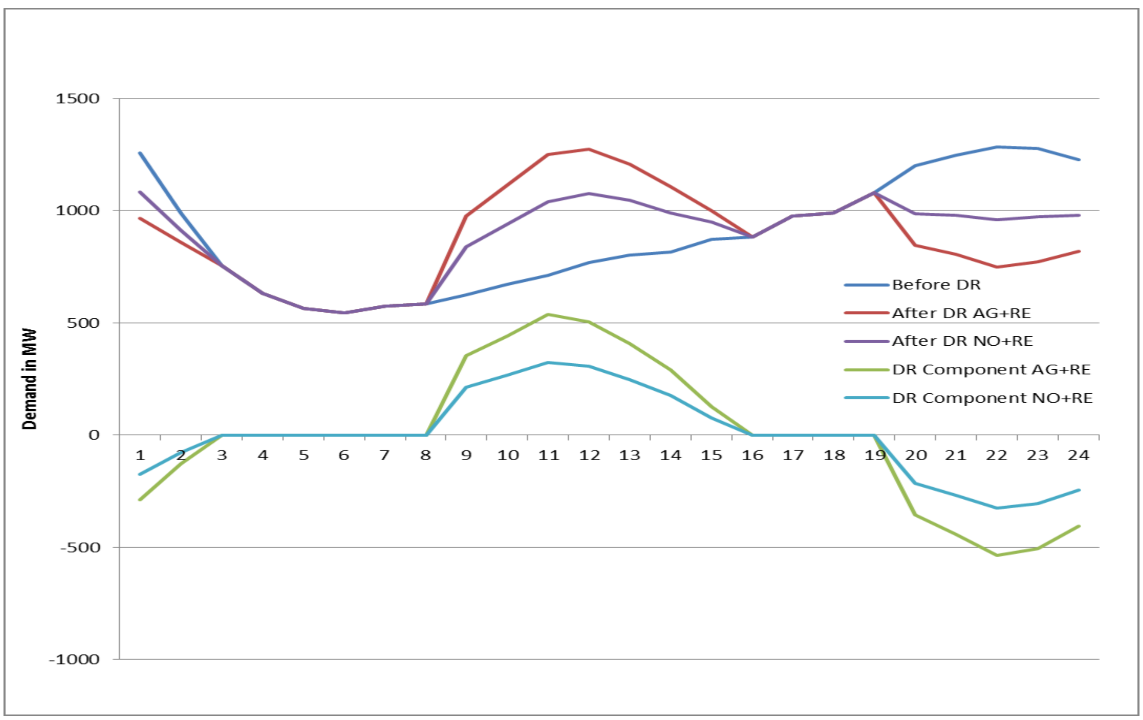


Figure 5-3: Minimum Demand Day



Current values for curtailment result from the simulations and shown in the following figures:

Figure 5-4: AG+RE Curtailment Comparison

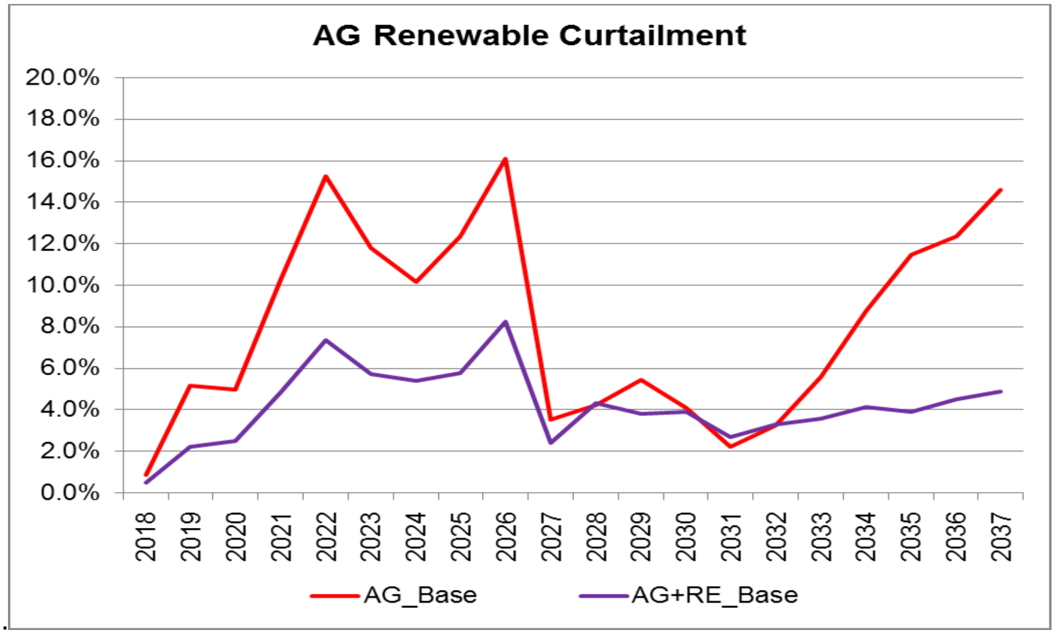
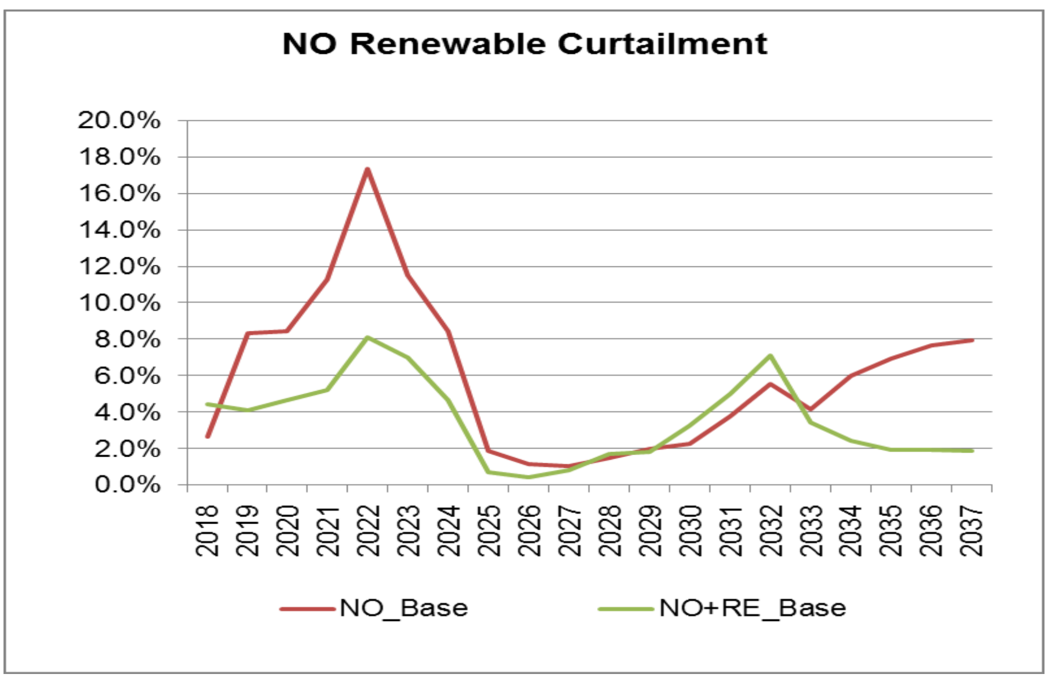


Figure 5-5: NO Renewable Curtailment Comparison



It should be noted that, while a curtailment of two (2) percent was used in the design of the demand response, the actual curtailment obtained was higher than the target due to the need of having more thermal generating units on line for regulation, than those considered in the design. This finding is further supported by the fact that the “night” or thermal curtailment increased significantly. Thermal curtailment is handled in practice by lowering the thermal units to their emergency lower limits where the capability to regulate is lost and operation could be challenging.

A demand response program increases the capability to incorporate more renewable PV generation (almost on a 1-to-1 relationship). This is what the model was designed to represent. Comparing the cost of the additional PV generation during the day with the savings from reduced conventional generation in the evening, the economic justifications for the implementation of the demand response program can be assessed.

In case it is determined to advance a demand response program, additional studies need to be conducted, including: (1) the market assessment and energy audits for identification of opportunities; (2) determine the target markets (i.e., commercial clients, industrial, residential); (3) design the incentive programs based on the resources that will become available as a result of the load shift and/or government incentives; and (4) roll out and monitor.

Section
6

Fuel Price Forecast

6.1 Introduction

The purpose of this section is to discuss the fuel price forecast used in the AOGP Economic Analysis. The Commission requested PREPA to prepare price forecasts based on the Henry Hub and West Texas Intermediate price forecasts in the Reference, High Oil and Low Oil Prices from the Energy Information Administration's 2017 edition of the Annual Energy Outlook. Also, the Commission requested PREPA to include any applicable adder or delivery charges applicable to the fuel purchases. (The Commission clarified these requirements.) Therefore, the forecast considers the fiscal years period of 2017-2037.

6.2 Data, Assumptions and Methodology

6.2.1 Fuel Prices Data

The historical daily values of fuel prices and adders since June 1, 2011, as well as the price formulas were used in the fuel price calculations. In addition, the contractual information and methodologies for fuel price calculations were considered, particularly for AES-PR, and for EcoEléctrica energy charge that includes a fuel component. As described below, price markers information to calculate the final price of fuel No. 2, No. 6 and Natural Gas are used for power generation. The most recent applicable formulas with historical values were used as historical prices.

The methodology and fuel price data were similar to those used by Siemens in the Supplemental IRP.

6.2.1.1 Historical Figures

Historical data of different fuel prices consider the period June 1, 2011, until February 2, 2017. The following considerations are of particular importance for the calculation of final prices for No. 6, No. 2, and Natural Gas:

- For No. 6 (with a 0.5%/weight sulfur content) price calculation, the following information is relevant:
    - 0.3%/weight sulfur content (High Pour) lowest and highest daily price as provided by Platt for New York/Boston cargo,
    - 0.7%/weight sulfur content lowest and highest daily price as provided by Platt for New York/Boston cargo.

- For No. 2 price calculation, the following information is relevant:
  - Ultra Low Sulfur Diesel (ULSD) lowest and highest daily price as provided by Platt for New York/Boston cargo,
  - ULSD lowest and highest daily price as provided by Platt for Gulf Coast,
  - ULSD lowest and highest daily price as provided by Argus for New York,
  - ULSD lowest and highest daily price as provided by Argus for Gulf Coast.
- For Natural Gas price calculation, the following information is relevant:
  - 0.3%/weight sulfur content (Low Pour) No. 6, lowest and highest daily price as provided by Platt for New York/Boston cargo,
  - 0.7%/weight sulfur content No. 6, lowest and highest daily price as provided by Platt for New York/Boston cargo.

Also, historical information of AES coal prices for years 2003 through 2016 was considered as used for power generation at AES-PR plant.

Appendix D-1 presents a summary of the historical data relevant to the fuel prices forecast.

6.2.1.2 Calculation Formulas

As mentioned above, PREPA uses formulas for calculating the price of fuels No. 6 and No. 2 and Natural Gas from the Costa Sur power plant contract based on price markers. Thus, for modeling and forecasting purposes, instead of working with each one of these markers individually, the formulas were used and the forecast series were generated for the resulting prices of No. 6, No. 2 and Natural Gas. The formulas are the following:

$$\begin{aligned}
&Price_t\,(No.6) = \\
&50\% \cdot \\
&[Average(0.3\%S@NYB\ Platts\ Highest\ Price_{t-1} + 0.3\%S@NYB\ Platts\ Lowest\ Price_{t-1} + \\
&0.3\%S@NYB\ Platts\ Highest\ Price_t + 0.3\%S@NYB\ Platts\ Lowest\ Price_t + \\
&0.3\%S@NYB\ Platts\ Highest\ Price_{t+1} + 0.3\%S@NYB\ Platts\ Lowest\ Price_{t+1})] + 50\% \cdot \\
&[Average(0.7\%S@NYB\ Platts\ Highest\ Price_{t-1} + 0.7\%S@NYB\ Platts\ Lowest\ Price_{t-1} + \\
&0.7\%S@NYB\ Platts\ Highest\ Price_t + 0.7\%S@NYB\ Platts\ Lowest\ Price_t + \\
&0.7\%S@NYB\ Platts\ Highest\ Price_{t+1} + 0.7\%S@NYB\ Platts\ Lowest\ Price_{t+1})]
\end{aligned} \quad [1]$$

Where

$Price_t$	:	Fuel price for day t, in dollars per barrel
$0.3\%S@NYB\ Platts\ Highest\ Price_{t-1}$	:	Highest price for day t-1 (previous day), in dollars per barrel, of 0.3% sulfur content diesel (High Pour) at New York/Boston cargo, according to Platts

$0.3\%S@NYB\ Platts\ Lowest\ Price_{t-1}$	:	Lowest price for day t-1 (previous day), in dollars per barrel, of 0.3% sulfur content diesel (High Pour) at New York/Boston cargo, according to Platts
$0.3\%S@NYB\ Platts\ Highest\ Price_{t}$	:	Highest price for day t (same day), in dollars per barrel, of 0.3% sulfur content diesel (High Pour) at New York/Boston cargo, according to Platts
$0.3\%S@NYB\ Platts\ Lowest\ Price_{t}$	:	Lowest price for day t (same day), in dollars per barrel, of 0.3% sulfur content diesel (High Pour) at New York/Boston cargo, according to Platts
$0.3\%S@NYB\ Platts\ Highest\ Price_{t+1}$	:	Highest price for day t+1 (next day), in dollars per barrel, of 0.3% sulfur content diesel (High Pour) at New York/Boston cargo, according to Platts
$0.3\%S@NYB\ Platts\ Lowest\ Price_{t+1}$	:	Lowest price for day t+1 (next day), in dollars per barrel, of 0.3% sulfur content diesel (High Pour) at New York/Boston cargo, according to Platts
$0.7\%S@NYB\ Platts\ Highest\ Price_{t-1}$	:	Highest price for day t-1 (previous day), in dollars per barrel, of 0.7% sulfur content diesel at New York/Boston cargo, according to Platts
$0.7\%S@NYB\ Platts\ Lowest\ Price_{t-1}$	:	Lowest price for day t-1 (previous day), in dollars per barrel, of 0.7% sulfur content diesel at New York/Boston cargo, according to Platts
$0.7\%S@NYB\ Platts\ Highest\ Price_{t}$	:	Highest price for day t (same day), in dollars per barrel, of 0.7% sulfur content diesel at New York/Boston cargo, according to Platts
$0.7\%S@NYB\ Platts\ Lowest\ Price_{t}$	:	Lowest price for day t (same day), in dollars per barrel, of 0.7% sulfur content diesel at New York/Boston cargo, according to Platts
$0.7\%S@NYB\ Platts\ Highest\ Price_{t+1}$	:	Highest price for day t+1 (next day), in dollars per barrel, of 0.7% sulfur content diesel at New York/Boston cargo, according to Platts
$0.7\%S@NYB\ Platts\ Lowest\ Price_{t+1}$	:	Lowest price for day t+1 (next day), in dollars per barrel, of 0.7% sulfur content diesel at New York/Boston cargo, according to Platts

$$Price_t\ (No.2) = 50\% \cdot [Average(ULSD@NYB\ Platts\ Highest\ Price_{t-1} + ULSD@NYB\ Platts\ Lowest\ Price_{t-1} + ULSD@NYB\ Platts\ Highest\ Price_t + ULSD@NYB\ Platts\ Lowest\ Price_t + ULSD@NYB\ Platts\ Highest\ Price_{t+1} + ULSD@NYB\ Platts\ Lowest\ Price_{t+1} + ULSD@GC\ Platts\ Highest\ Price_{t-1} + ULSD@GC\ Platts\ Lowest\ Price_{t-1} + ULSD@GC\ Platts\ Highest\ Price_t + ULSD@GC\ Platts\ Lowest\ Price_t + ULSD@GC\ Platts\ Highest\ Price_{t+1} + ULSD@GC\ Platts\ Lowest\ Price_{t+1})] + 50\% \cdot [Average(ULSD@NYB\ Argus\ Highest\ Price_{t-1} + ULSD@NYB\ Argus\ Lowest\ Price_{t-1} + ULSD@NYB\ Argus\ Highest\ Price_t + ULSD@NYB\ Argus\ Lowest\ Price_t + ULSD@NYB\ Argus\ Highest\ Price_{t+1} + ULSD@NYB\ Argus\ Lowest\ Price_{t+1} + ULSD@GC\ Argus\ Highest\ Price_{t-1} + ULSD@GC\ Argus\ Lowest\ Price_{t-1} + ULSD@GC\ Argus\ Highest\ Price_t + ULSD@GC\ Argus\ Lowest\ Price_t + ULSD@GC\ Argus\ Highest\ Price_{t+1} + ULSD@GC\ Argus\ Lowest\ Price_{t+1})] \cdot 0.42 \quad [2]$$

Where:

$Price_t$	:	Fuel price for day t in dollars per barrel,
$ULSD@NYB\ Platts\ Highest\ Price_{t-1}$	:	Highest price for day t-1 (previous day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Platts
$ULSD@NYB\ Platts\ Lowest\ Price_{t-1}$	:	Lowest price for day t-1 (previous day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Platts
$ULSD@NYB\ Platts\ Highest\ Price_t$	:	Highest price for day t (same day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Platts
$ULSD@NYB\ Platts\ Lowest\ Price_t$	:	Lowest price for day t (same day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Platts
$ULSD@NYB\ Platts\ Highest\ Price_{t+1}$	:	Highest price for day t+1 (next day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Platts
$ULSD@NYB\ Platts\ Lowest\ Price_{t+1}$	:	Lowest price for day t+1 (next day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Platts
$ULSD@GC\ Platts\ Highest\ Price_{t-1}$	:	Highest price for day t-1 (previous day), in dollars per barrel, of ULSD at Gulf Coast, according to Platts
$ULSD@GC\ Platts\ Lowest\ Price_{t-1}$	:	Lowest price for day t-1 (previous day), in dollars per barrel, of ULSD at Gulf Coast, according to Platts
$ULSD@GC\ Platts\ Highest\ Price_t$	:	Highest price for day t (same day), in dollars per barrel, of ULSD at Gulf Coast, according to Platts
$ULSD@GC\ Platts\ Lowest\ Price_t$	:	Lowest price for day t (same day), in dollars per barrel, of ULSD at Gulf Coast, according to Platts

$ULSD@GC\ Platts\ Highest\ Price_{t+1}$	:	Highest price for day t+1 (next day), in dollars per barrel, of ULSD at Gulf Coast, according to Platts
$ULSD@GC\ Platts\ Lowest\ Price_{t+1}$	:	Lowest price for day t+1 (next day), in dollars per barrel, of ULSD at Gulf Coast, according to Platts
$ULSD@NYB\ Argus\ Highest\ Price_{t-1}$	:	Highest price for day t-1 (previous day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Argus
$ULSD@NYB\ Argus\ Lowest\ Price_{t-1}$	:	Lowest price for day t-1 (previous day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Argus
$ULSD@NYB\ Argus\ Highest\ Price_{t}$	:	Highest price for day t (same day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Argus
$ULSD@NYB\ Argus\ Lowest\ Price_{t}$	:	Lowest price for day t (same day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Argus
$ULSD@NYB\ Argus\ Highest\ Price_{t+1}$	:	Highest price for day t+1 (next day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Argus
$ULSD@NYB\ Argus\ Lowest\ Price_{t+1}$	:	Lowest price for day t+1 (next day), in dollars per barrel, of ULSD at New York/Boston cargo, according to Argus
$ULSD@GC\ Argus\ Highest\ Price_{t-1}$	:	Highest price for day t-1 (previous day), in dollars per barrel, of ULSD at Gulf Coast, according to Argus
$ULSD@GC\ Argus\ Lowest\ Price_{t-1}$	:	Lowest price for day t-1 (previous day), in dollars per barrel, of ULSD at Gulf Coast, according to Argus
$ULSD@GC\ Argus\ Highest\ Price_{t}$	:	Highest price for day t (same day), in dollars per barrel, of ULSD at Gulf Coast, according to Argus
$ULSD@GC\ Argus\ Lowest\ Price_{t}$	:	Lowest price for day t (same day), in dollars per barrel, of ULSD at Gulf Coast, according to Argus
$ULSD@GC\ Argus\ Highest\ Price_{t+1}$	:	Highest price for day t+1 (next day), in dollars per barrel, of ULSD at Gulf Coast, according to Argus
$ULSD@GC\ Argus\ Lowest\ Price_{t+1}$	:	Lowest price for day t+1 (next day), in dollars per barrel, of ULSD at Gulf Coast, according to Argus

$$Price\ Index_t\ (Natural\ Gas) = \frac{1}{n}\cdot\sum_{i=1}^{n}(0.3\%S@NYB\ Platts\ Highest\ Price_i + 0.3\%S@NYB\ Platts\ Lowest\ Price_i + 0.7\%S@NYB\ Platts\ Highest\ Price_i + 0.7\%S@NYB\ Platts\ Lowest\ Price_i) \quad [3]$$

Where:

$Price\ Index_t$	:	Fuel price index for day t, in dollars per barrel
n	:	Number of days of previous quarter
i	:	Each day of previous quarter
$0.3\%S@NYB\ Platts\ Highest\ Price_i$	:	Highest price for day i, in dollars per barrel, of 0.3% sulfur content diesel (Low Pour) at New York/Boston cargo, according to Platts
$0.3\%S@NYB\ Platts\ Lowest\ Price_i$	:	Lowest price for day i, in dollars per barrel, of 0.3% sulfur content diesel (Low Pour) at New York/Boston cargo, according to Platts
$0.7\%S@NYB\ Platts\ Highest\ Price_i$	:	Highest price for day i, in dollars per barrel, of 0.7% sulfur content diesel at New York/Boston cargo, according to Platts
$0.7\%S@NYB\ Platts\ Lowest\ Price_i$	:	Lowest price for day i, in dollars per barrel, of 0.7% sulfur content diesel at New York/Boston cargo, according to Platts

The price index for natural gas is defined by the formula presented above. In addition, to calculate the natural gas price using this index, the following formula is used:

$$Price\ _t\ (Natural\ Gas) = Price\ Index_t \cdot 0.124 + 1.5 \quad [4]$$

Where

$Price_t$	:	Natural gas price for day t, in dollars per MMBtu
$Price\ Index_t$	:	Fuel price index for day t, in dollars per barrel
n	:	Number of days of previous quarter

However, this formula is only applicable until September 30th, 2015. Starting in October 1st, 2015, the following formula will apply:

$$Price\ _t\ (Natural\ Gas) = 50\% \cdot P1 + 50\% \cdot P2 \quad [5]$$

Where

$Price_t$	:	Natural gas price for day t, in dollars per MMBtu

And

$$P1 = Price\ Index_t \cdot 0.1215 + 1.125 \quad [6]$$

$Price\ Index_t$	:	is the unweighted average for the 6-month period prior to the relevant quarter of the mean dated fuel with zero point five percent (0.5%) sulfur as interpolated from the means of zero point three percent (0.3%) sulfur LP and zero point seven percent

(0.7%) sulfur fuels, as published by the Platts' Oilgram Price Report PRICE AVERAGE SUPPLEMENT, Estimated New York spot No. 6 Fuel Oil Cargo columns, rounded to two (2) decimal places

$$P2 = HH \cdot 1.15 + 5.95 \qquad [7]$$

$Price_t$	:	Natural gas price for day t, in dollars per MMBtu
$Price\ Index_t$	:	HH (in US$/MMBtu) is the final settlement price for the New York Mercantile Exchange's Henry Hub natural gas futures contracts for the month previous to the month of delivery, rounded to two (2) decimal places

The formula for natural gas price calculation, applicable until September 30, 2015, is completely indexed to liquid fuels price (0.3%/weight sulfur LP and 0.7%/weight sulfur), while the formula to be applied from October 1st forward is half indexed to liquid fuels price and half to the price of natural gas at Henry Hub.

In addition, the fuel component of the energy price applicable to EcoEléctrica has two components: the "Energy Purchase Price" (EPP), which applies to power generation under 76% of EcoEléctrica plant capacity, and the "Spot Fuel Price" that contractually is defined as the backup fuel at EcoEléctrica plant. The formula for calculation of EPP is the following:

$$EPP \;=\; [NBV\ x\ (ri/ro)\ x\ 0.5] \;+\; [0.01957\ x\ (gi/go)\ x\ 0.5] \qquad [8]$$

Where:

NBV	:	New Base Value (as per Second Amendment to the PPOA)
ri	:	Average of the twelve (12) monthly values of the US-CPI for the twelve (12) Months ending on December 31 of the Year immediately prior to the date of the adjustment
ro	:	US-CPI for Base Year 2003
gi	:	U.S. Spot Gas Price for prior year
go	:	U.S. Spot Gas Price Base Value (65%-35%)

As per the PPOA, the U.S. Spot Gas Index is defined as the average of the thirty-six (36) values representing the New York Mercantile Exchange ("NYMEX") closing prices on the last three (3) trading Days of the NYMEX natural gas futures contracts for each of the twelve (12) Months of the prior year. For the purpose of the fuel price forecasting, and because the estimations were handled exclusively as monthly values, the U.S. Spot Gas was defined as the average the twelve (12) months of the prior year. In addition:

$$NBV = FA\ x\ 0.01957\ = \frac{CPI_{PR-2003}}{CPI_{PR-January\ 1994}} \cdot 0.01957 = \frac{221.1}{128.3} \cdot 0.01957 = \ 0.033725 \qquad [9]$$

Where:

$CPI_{PR-2003}$	:	Average for year 2003 of Consumer Price Index (CPI) in Puerto Rico
$CPI_{PR-January\ 1994}$	:	Consumer Price Index (CPI) in Puerto Rico at January 1994

As shown in this report, the price of coal delivered to AES-PR has been settled by contract until 2019. AES-PR plant burns Colombian coal. From year 2020 forward, the coal price to AES-PR is defined as follows:

$$Price_{t,Y} = \ Average(Price_{Y-1}) \cdot YOYGR\ (Price_Y(Reference)) \qquad [10]$$

Where:

$Price_{t,Y}$	:	Price of coal delivered to AES-PR for month t and year Y, in dollars per MBtu
$Price_{Y-1}$	:	Monthly prices of coal delivered to AES-PR during for year Y-1, in dollars per MMBtu
$YOYGR\ (Price_Y(Reference))$	:	Year-over-year growth rate (estimated average for year Y divided by estimated average for Y-1) of reference coal price, in dollars per MMBtu

The coal price for the 12 months of a calendar year is assumed to be same.

6.2.1.3 Other Relevant Information

The historical and current adders were applied to calculate final prices of the fuel delivered to the different locations where they are used for power generation. In specific, the adders are applied to calculate prices delivered at the following locations and/or plants:

- Fuel No. 6:
    - San Juan/Palo Seco,
    - Aguirre
    - Costa Sur
- Fuel No. 2:
    - Aguirre/San Juan combined cycles,
    - Mayagüez/Arecibo,

Information regarding the fuel adders is summarized in Appendix D-2.

Finally, the factors (heat content) to convert barrels of fuel and metric tons of coal into energy were included as part of the information provided by PREPA, as follows:

- Fuel No. 6: 6.3 MMBtu/BBL,
- Fuel No. 2: 5.8 MMBtu/BBL,

6.2.2 Review of Data Obtained from other sources

As described in the next subsections, the price of the different fuels considered in the preparation of this analysis will be linked or indexed to the following variables from EIA:

- The West Texas Intermediate (WTI) historic oil price,
- The WTI projected prices for the Reference, High Oil, and Low Oil Fuel scenarios (Nominal Values),
- The Coal, Distillate and Residual at Electric Power historic prices,
- The Coal, Distillate and Residual at Electric Power projected prices for the Reference, High Oil, and Low Oil Fuel scenarios (Nominal Values),
- The historic prices of natural gas price at Henry Hub,
- The natural gas projected prices at Henry Hub for the Reference, High Oil, and Low Oil Fuel scenarios (Nominal Values).

The data of these variables was obtained from the Energy Information Administration (EIA) website, and it is summarized in Appendix D-1 and D-3. In addition, the Annual Energy Outlook 2017 (AEO2017) was used to obtain the Reference, High Oil, and Low Oil corresponding values.

6.2.3 Assumptions

The projected fuel prices are based on the 2017 Annual Energy Outlook. The reference, high oil and low oil have the following assumptions:

- The reference case is based on the central views of economic forecasters and demographers,
- The reference case assumes that current laws and regulations affecting the electric sector are unchanged through the projection period,
- The high oil price for residual reach values of 334 dollars per barrel for the year 2037 compared with 177 dollars per barrel in the reference case and 41 dollars per barrel in the low oil case,
- The high oil assumes a higher demand of petroleum products, lower investments by the Organization of the Petroleum Exporting Countries (OPEC)

and higher exploration and development costs. The Low Oil case assumes the opposite.

- The low oil case assumes that prices are too low and do not provide incentives for a high production.
- The reference case considers the Clean Power Plan in order to reduce the CO_2.
- According to the 2017 Annual Energy Outlook the current crude oil prices are at the lowest levels since 2004. Also, the natural gas prices are the lowest since 1990. For this reason, in the reference case the oil prices were projected to rise faster in the near term than in the long term.
- The natural gas prices in the reference case rise in the short term and then remain flat.

The forecast was developed for the period 2017-2037.

The approach consisted of finding an econometric model indexing the price of fuels No. 6 and No. 2 to an oil marker.

- The models of fuels No. 2, No. 6 and Natural Gas prices, including the energy price of EcoEléctrica, are referred to values calculated with the formulas in the contracts.

6.2.4 Methodology

The methodology used entailed the following:

- Developing an econometric model of price for the West Texas Intermediate (WTI), to obtain a forecast of average monthly prices until June 2037. Different variables were considered in the preparation of this model.
- Linking the price of the different fuels used for power generation to the WTI. The link consisted of regression models.
- Use the forecast of WTI and the models linking WTI and other fuels to develop a forecast of average monthly prices of the fuels used for power generation.

To obtain the mathematical models, EViews® software was used. This software is used by government agencies, academic, researchers and companies as a statistical tool to forecast. The Energy Administration Information used EViews® to develop the National Energy Modeling System[7] an economic and energy model.

The criterion to select these models for forecasting fuels was the goodness-of-fit of the models, especially the value of the R-squared. The R-squared is a statistical measure of how close data fitted the regression line. In general, the model fits the data well if the differences between the observed values and the model's predicted values are small

[7] HIS, About HIS EViews, http://www.eviews.com/general/about_us.html

and unbiased.[8] The R-squared is a value between 0 and 100% and generally, higher the value, better the model fit the data.

6.2.4.1 Econometric Models

The econometric model and the projected dependent variable were obtained from the EViews® results. The inputs to this software were the historical fuel prices and the historical fuel indicators obtained from the EIA. Also, the projected fuel indicators from the EIA were provided to the software in order to obtain the fuel forecasted prices.

The annual rate of change from the dependent variable was calculated and then applied to the historical values to obtain the annual fuel projected prices.

6.3 Results

The results were:

- Forecasting models for No. 2 and No. 6 fuels, Natural Gas, and Coal for the Reference, High Oil, and Low Oil scenarios.
- Forecast values for the different fuel types considered.
- Assumed values for shipping adders, consistent with historical values, current PREPA financial restrictions, and assumptions presented before.
- Estimated delivery prices for the different fuel types considered.

6.3.1 Obtained Models for Fuel Price Forecast

For the No. 6 fuel price forecast, the econometric model obtained for the reference and high oil scenarios based on the WTI was:

$$LN\_PRICE\_No6_t = 1.247435 \cdot LN\_PRICE\_WTI_t - 1.01357$$

Where:

$LN\_PRICE\_No6_t$	:	Natural logarithm of average price of Reference or High Oil Scenarios of No. 6 fuel for year t, in dollars per BBL
$LN\_PRICE\_WTI_t$	:	Natural logarithm of average price of Reference and High Oil Scenarios WTI for year t, in dollars per BBL

For the No. 6 fuel price forecast, the econometric model obtained for the low oil scenario based on the WTI was:

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[8] Minitab.com, Regression Analysis: How Do I Interpret R-squared and Assess the Goodness-of-Fit?, http://blog.minitab.com/blog/adventures-in-statistics-2/regression-analysis-how-do-i-interpret-r-squared-and-assess-the-goodness-of-fit.

$$LN\_PRICE\_No6_t = 1.247552 \cdot LN\_PRICE\_WTI_t - 1.01418$$

Where:

$LN\_PRICE\_No6_t$	:	Natural logarithm of average price of Low Oil Scenario of No. 6 fuel for year t, in dollars per BBL
$LN\_PRICE\_WTI_t$	:	Natural logarithm of average price of Low Oil Scenario WTI for year t, in dollars per BBL

The model obtained for the reference and high oil scenarios of the No. 2 fuel price forecast is similar to the one obtained for No. 6. without lagged variables, as shown below:

$$LN\_PRICE\_No2_t = 0.975184 \cdot LN\_PRICE\_WTI_t + 0.389523$$

Where:

$LN\_PRICE\_\_No2_t$	:	Natural logarithm of average price of Reference and High Oil Scenarios of No. 2 fuel for year t, in dollars per BBL
$LN\_PRICE\_MBTU\_WTI_t$	:	Natural logarithm of average price of WTI for year t, in dollars per BBL

The model obtained for the low oil scenario No. 2 fuel price forecast is similar to the one obtained for No. 6, without lagged variables, as shown below:

$$LN_{PRICE_{No2}\,t} = 0.975254 \cdot LN\_PRICE\_WTI_t + 0.389135$$

Where:

$LN\_PRICE\_\_No2_t$	:	Natural logarithm of average price of Low Oil Scenario of No. 2 fuel for year t, in dollars per BBL
$LN\_PRICE\_MBTU\_WTI_t$	:	Natural logarithm of average price of WTI for year t, in dollars per BBL

The model obtained for Costa Sur Natural Gas price for the reference, high oil and low oil scenarios is shown below:

$$LN\_MBTU\_NG_t = 0.476051 \cdot LN\_PREPANo6_{\,t-3} + 0.1878695 \cdot LN\_HH_t + 0.014695$$

Where:

$LN\_MBTU\_NG_t$	:	Natural logarithm of natural gas average price for month t indexed to fuel No. 6, in dollars per MMBtu

$LN\_PREPANo6_{t-3}$	:	Natural logarithm of PREPA system residual average price for month t-3 for the reference, high oil and low oil scenarios, in dollars per BBL
LN_HH_t	:	Natural logarithm of Henry Hub average price for month t for the reference, high oil and low oil scenarios, in dollars per MMBtu

Finally, the model obtained for the Coal used by AES is similar to those for natural gas, with a combination of current and lagged variables, as shown below:

$$LN\_PRICE\_MBTU\_COAL_t = 2.30998 \cdot LN\_PRICE\_COALREF_{t-2} + 0.12782 \cdot LN\_PRICE\_WTI_t - 0.978367 \quad [16]$$

Where:

$LN\_PRICE\_MBTU\_COAL_t$	:	Natural logarithm of AES Coal average price for year t, in dollars per MMBtu
$LN\_PRICE\_MBTU\_COALREF_{t-2}$	:	Natural logarithm of Coal for Power Sector from EIA for the reference, high oil and low oil scenarios average price for year t-2, in dollars per MMBtu
$LN\_PRICE\_MBTU\_WTI_t$	:	Natural logarithm of WTI average price for year t, in dollars per MMBtu

The Natural Gas for the Aguirre Complex (Aguirre Steam Units and Combined Cycle) was calculated with the following formula:

$$Price\ of\ Natural\ Gas_t = 1.15 \cdot Henry\ Hub + 4.0$$

In the scenarios that include AOGP, it was assumed that the price of the Costa Sur Natural Gas will be the same as the Aguirre Complex.

The Henry Hub index projected values for the Reference, High Oil and Low Oil scenarios are presented in Appendix D-3.

The EPP was input to PROMOD IV® as the EcoEléctrica fuel price when its power energy dispatch is under 76%. When this percentage is 76% or above, the EcoEléctrica fuel price was assumed to be the same as No. 2.

The EPP calculated for January 2017 was calculated as follows:

$$EPP = [0.033725\ x\ (ri/ro)\ x\ 0.5] + [0.01957\ x\ (gi/go)\ x\ 0.5]$$

Where:

ri	:	245.527 (Assuming a CPI of 2.3%.)
ro	:	184

gi	:	2.50447 (Henry Hub average previous 12 months. After year 2018, this value is the projected index for the reference, high oil and low oil scenarios.)
go	:	1.99930695

$$EPP_{Jan\ 2017} = 4.6345\ \$/MBTU$$

6.3.2 Adders

The adders were applied to the forecasted prices of No. 6 and No. 2, according to the different locations for power generation. For natural gas, an adder of $4/MMBtu was assumed. It was assumed that the value of the adders remain the same for the reference, high oil and low oil scenarios.

Table 6-1: Shipping Adders Considered for Fuel Price Forecasting

Fuel Type	Location	January 2017 Forward $/MMBtu
No. 6	San Juan / Palo Seco	0.9100
	Aguirre	1.2400
	Costa Sur	1.2400
No. 2	Aguirre / San Juan CC	1.2900
	Mayagüez / Arecibo	1.2900

6.3.3 Results for Fuel Price Forecast

Figure 6-1, 6-2, and 6-3 graphically show the price forecasting for No.2 and No. 6 over the period of 2017-2037 for the reference, high oil and low oil scenarios.

Based on the information obtained, the following aspects can be highlighted:

- Prices for No. 6 and No. 2 show a similar upward trend and cyclical pattern.
- An annual rate of change was calculated from the prices obtained by the econometric formulas. These annual rates were applied to the fuel price values to obtain the fuel price forecast for subsequent years.
- Seasonal Factors were used to convert annual values to monthly values.
- In the High Oil Scenario, No. 6 is more expensive than No. 2 after fiscal year 2033 as shown in Figure 6-2.

  In *Table 3. Energy Prices by Sector and Source* from the 2017 Annual Energy Outlook, the distillate oil prices from 2016 through 2050 are higher than the residual in all the scenarios (reference, high oil, and low oil). Moreover, PREPA's historical values for No. 2 oil prices have been always higher than those of No. 6.

Figure 6-1: Price Forecast for No. 6 and No. 2 – Reference Scenario

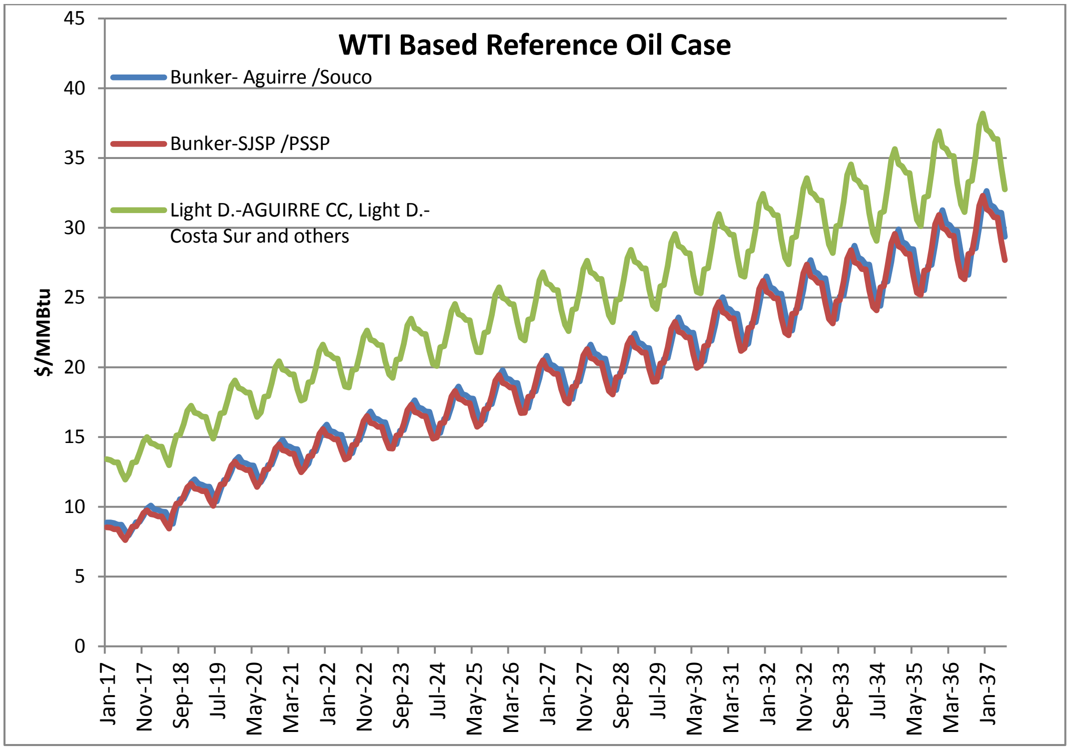


Figure 6-2: Price Forecast for No. 6 and No. 2 – High Oil Scenario

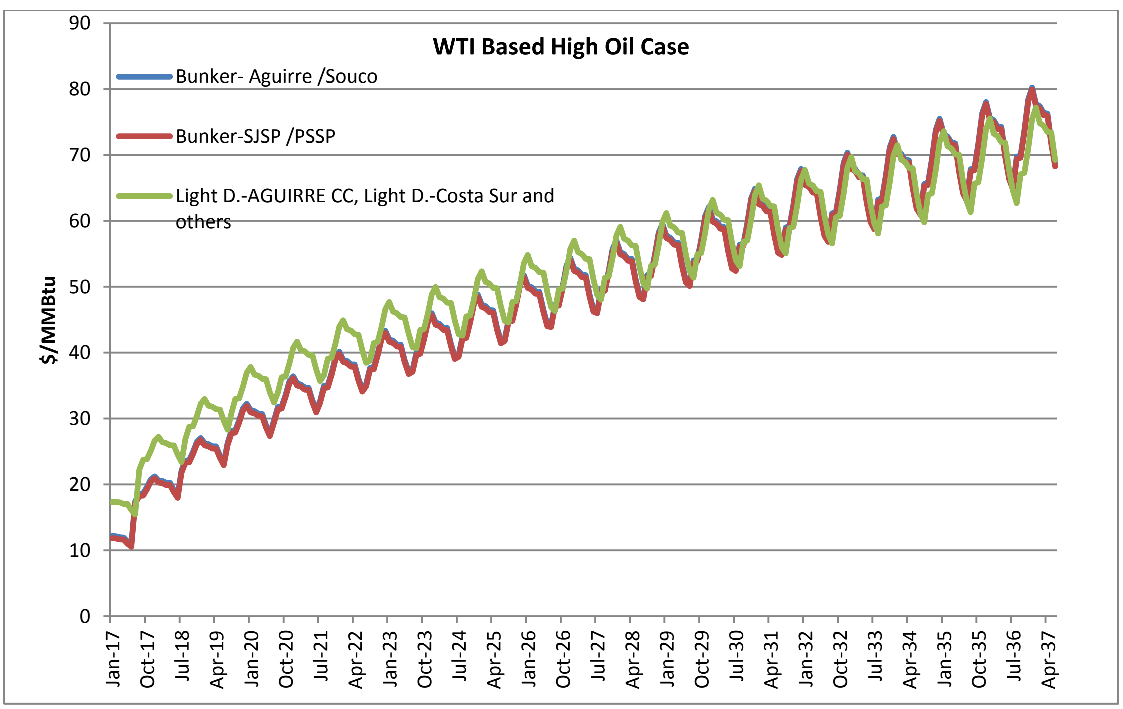
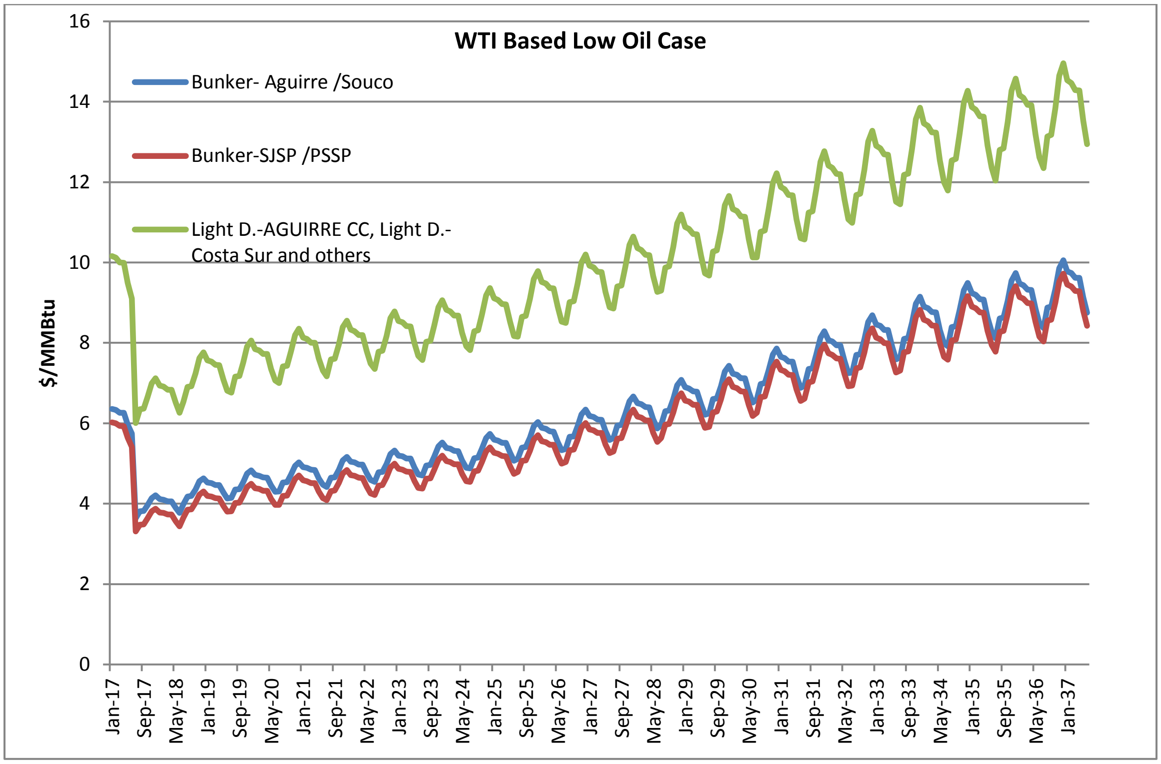


Figure 6-3: Price Forecast for No. 6 and No. 2 – Low Oil Scenario



Appendix D-2 shows historical adders, while Appendixes D-4 and D-5 present the adders assumed for forecasting purposes.

On March 29, 2017, PREPA requested the Commission to allow changes to the fuel price projections calculations for No. 2 and No. 6 from WTI to Distillate Fuel Oil and Residual Fuel Oil from the 2017 Energy Outlook. On March 30, 2017, the Commission granted PREPA's petition.

6.3.4 Revised Projections for No. 2 and No. 6

For the No. 6 fuel price forecast for the reference, high oil and low scenarios based on prices for the Electric Power Sector of the EIA, the econometric model obtained was:

$$LN\_PRICE\_No6_t = 1.204472 \cdot LN\_PRICE\_EIARES_t + 1.061426$$

Where:

$LN\_PRICE\_No6_t$	:	Natural logarithm of average price of Reference, High Oil and Low Oil Scenarios of No. 6 fuel for year t, in dollars per BBL
$LN\_PRICE\_EIARES_t$	:	Natural logarithm of average price EIA Residual for year t, in dollars per MBTU (Reference, High Oil and Low Oil Scenarios)

The model obtained for the reference and high oil scenarios No. 2 fuel price forecast was based on EIA prices for the Electric Power Sector. The results are similar to the one obtained for No. 6: without lagged variables, as shown below:

$$LN\_PRICE\_No2_t = 1.130679 \cdot LN\_PRICE\_EIADES_t + 1.283763 \quad [13]$$

Where:

$LN\_PRICE\_\_No2_t$	:	Natural logarithm of average price of Reference and High Oil Scenarios of No. 2 fuel for year t, in dollars per BBL
$LN\_PRICE\_EIADES_t$	:	Natural logarithm of average price of EIA Distillate for year t, in dollars per MBTU (Reference, High Oil and Low Oil Scenarios)

6.3.5 Results of Delivered Fuel Prices Forecasting

The Figure 6-4, 6-5, and 6-6 below summarize the results of the price forecasting exercise plus shipping adders to estimate future delivered fuel prices at each location for power generation over the period 2017-2037 for the reference, high oil and low oil scenarios.

- Regardless of their location in the curves, the price series for Bunker and Light Distillate show the upward trend and cyclical pattern, except for the low oil scenario.

Figure 6-4: Price Forecast – Reference Scenario

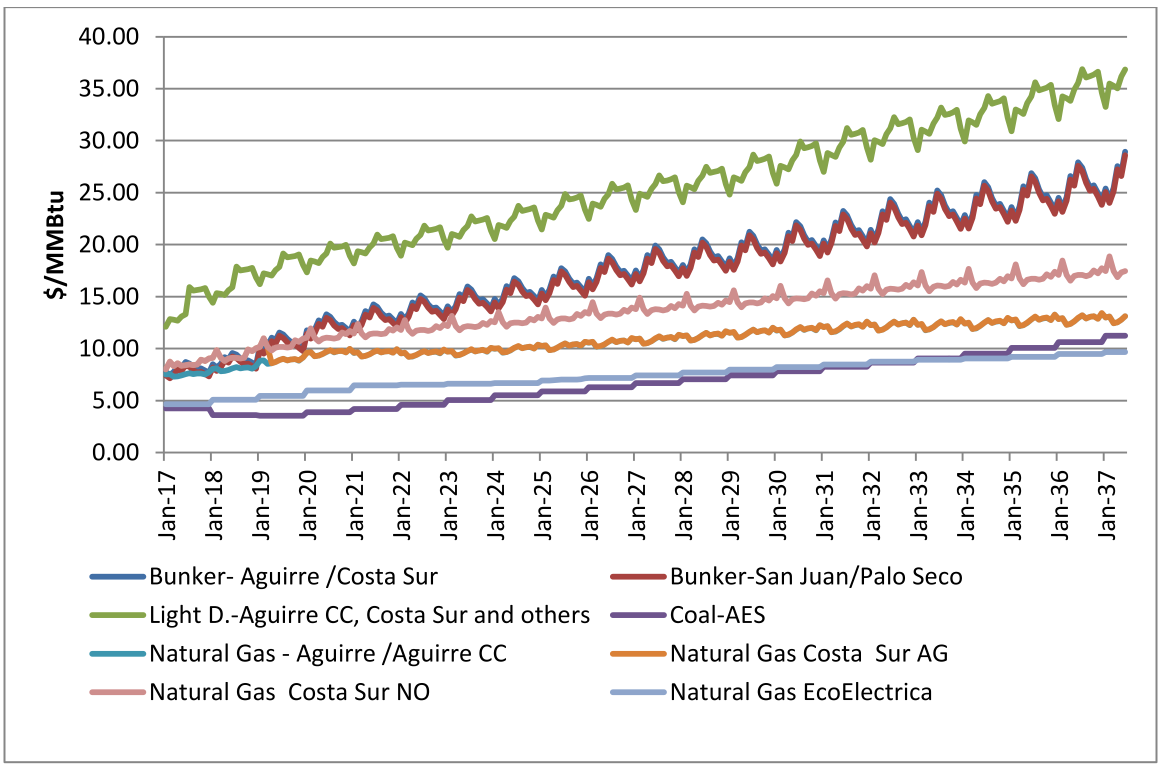


Figure 6-5: Price Forecast – High Oil Scenario

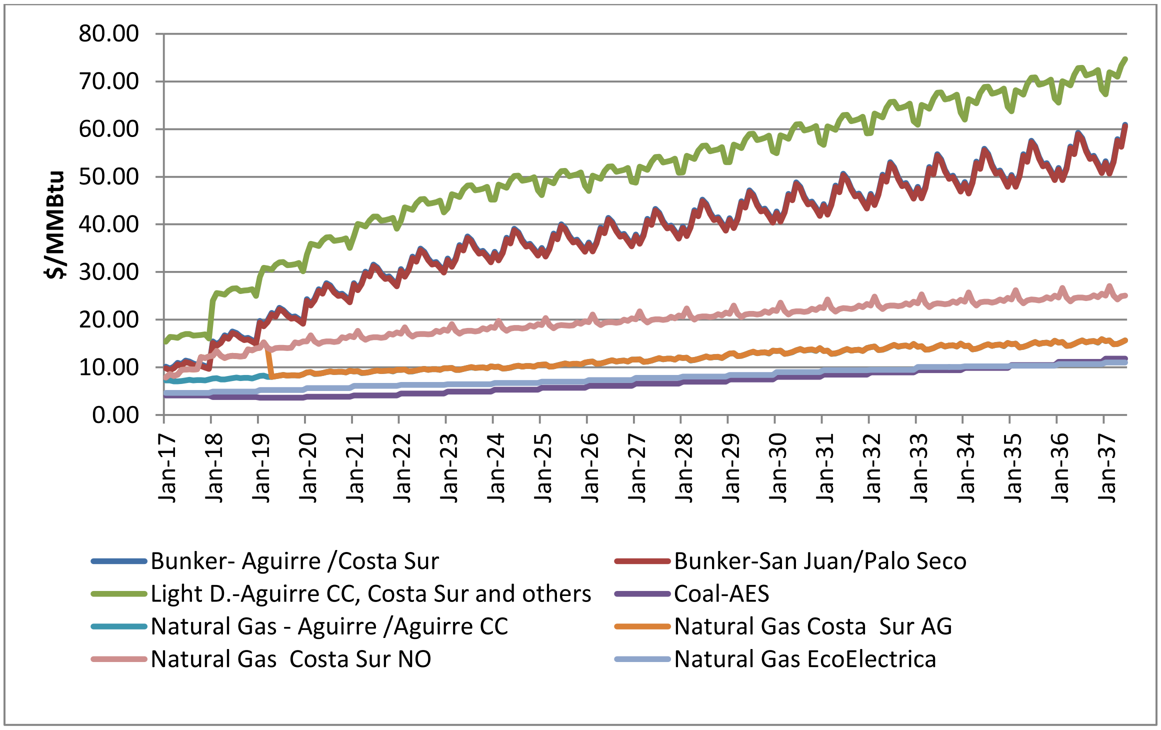
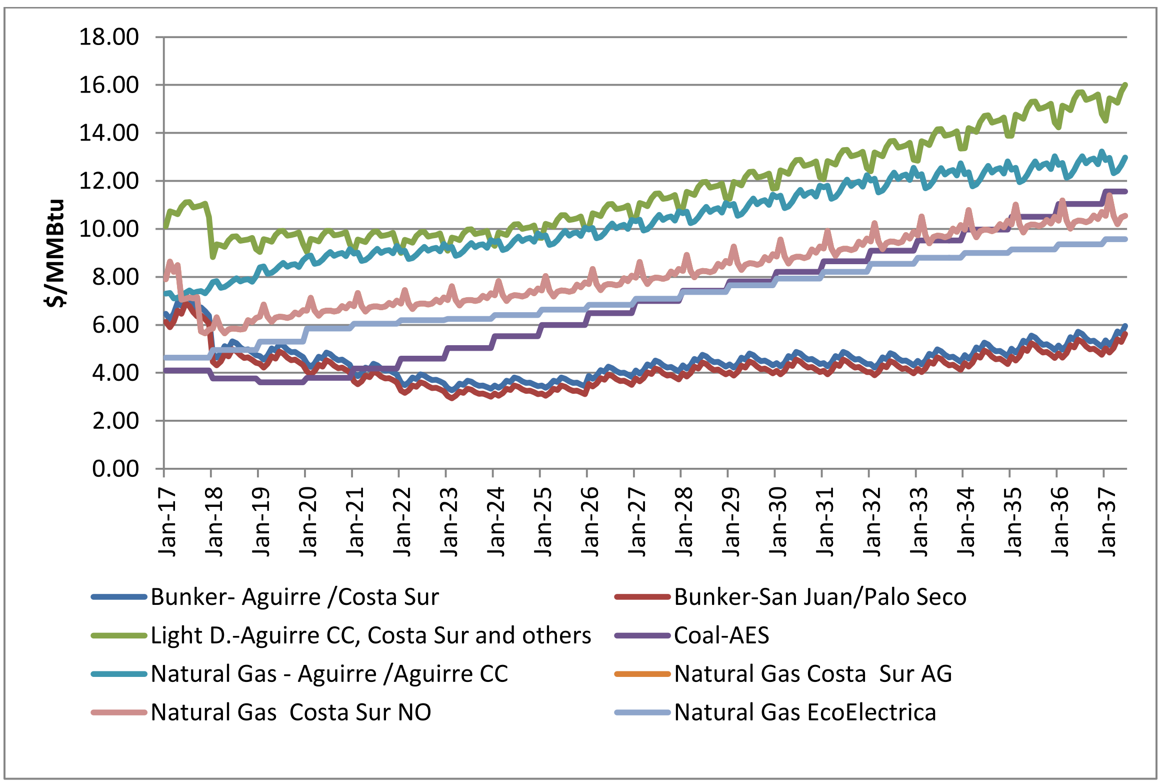


Figure 6-6: Price Forecast – Low Oil Scenario



The full set of values of these delivered fuel prices is presented in Appendix D-6.

Section
7

MATS Compliance

The Base IRP includes the steps necessary for PREPA to meet its Mercury and Air Toxics Standards (MATS) obligations.

All of PREPA's existing 14 steam units (approximately 2,900 MW of total capacity) are subject to MATS. Costa Sur 5&6 steam units are in compliance with MATS as they are currently burning natural gas and No. 6 fuel oil in a dual-fuel firing mode. For MATS purposes, Costa Sur 3&4, Palo Seco 1&2, and San Juan 7&8 have been designated as limited use[9] units and will operate in that mode until such time as they are retired.

Any settlement negotiation with federal and state regulatory authorities, regarding Palo Seco 3&4 and San Juan 9&10 units will materially impact near term power supply costs. In this analysis, for the AG scenarios, continued operation of San Juan 9&10 and of Palo Seco 3&4 is required through December 31, 2022. Thereafter, San Juan 9&10 are assumed to be retired and Palo Seco 3&4 are assumed to be declared as limited use. During that time those units would burn No. 6 fuel oil. In the NO scenarios, continued operation of San Juan 9&10 is required through December 31, 2021 when they retire, and continued operation of Palo Seco 3&4 is assumed until December 31, 2023, when they are declared limited use.

PREPA's recommended plan for MATS Compliance at Aguirre 1&2 steam units depends on the availability of natural gas to be supplied by the AOGP. As with San Juan and Palo Seco units, it is assumed that Aguirre 1&2 steam units will be included in a settlement agreement with the federal government in a manner to allow for their continued operation until their conversion to natural gas or their retirement, as they are also critical to electrical system's safety and reliability. Under such a circumstance, Aguirre 1&2 would continue to burn No. 6 fuel oil due to the unavailability of natural gas.

The Commission's order of February 10, 2017 reflects that AOGP is an essential component of PREPA's proposed IRP as it is a critical component of securing permanent, consistent and expeditious compliance with the federal Clean Air Act's MATS program. Prompt completion of AOGP will ensure that PREPA does not incur additional and unnecessary civil penalties, which ultimately would be paid by the citizens of the Commonwealth of Puerto Rico. Therefore, the AOGP's cost-benefit analysis must reflect the strong likelihood that PREPA will incur significant additional civil penalties from delayed compliance with the Clean Air Act

[9] Limited use units will have an annual heat input capacity factor of less than 8 percent over 24 month periods.

without the wider AOGP Project (conversions of Aguirre boilers 1&2 and Combined Cycle units, as well as AOGP construction).

The potential penalties grow as the delay to the Project continues or if changes are made. PREPA has stated on multiple occasions that changes to the proposed Project will require PREPA to re-evaluate the engineering bases of the project, re-assess the environmental impacts of those proposed changes, modify pending permit applications to reflect those changes, and re-submit its permit applications to the regulatory authorities to reinitiate the permitting process. The permitting process alone will engender considerable additional delay in the Project. For example, Clean Air Act pre-construction permits (which are required here) take at a minimum eighteen to twenty-four months for the federal regulatory authorities to issue, which does not include any additional time associated with potential permit appeals and challenges.

In view of the above, PREPA conducted analyses of the economic impact of the Commission's directed resource plan options.

For AG scenarios, PREPA assumed that the Project will be completed by April 1, 2019, which reflects the earliest expected online date. PREPA considered statutory penalties to accrue from July 1, 2017, to March 31, 2019 at a rate of $93,750 per violation per day occurring thereof, as per Table 2 – Civil Monetary Penalty Inflation Adjustments of 40 C.F.R. § 19.4. PREPA also considered dates when generating units are scheduled to be out of service due to programmed maintenance or environmental outages. PREPA estimates the maximum statutory civil penalties at $83,156,000 for the period from July 1, 2017, to March 31, 2019.

For the AG scenario where AOGP is delayed, PREPA assumed that the Project to be completed by April 1, 2020, which reflects a one-year delay from the earliest expected online date due to permitting and financing constraints. PREPA considered statutory penalties to accrue from July 1, 2017, to March 31, 2020 at the same rates as in AG scenarios. As before, PREPA also considered dates when generating units are scheduled to be out of service due to programmed maintenance or environmental outages. PREPA estimates the maximum statutory civil penalties under this scenario at $148,969,000 for the period from July 1, 2017, to March 31, 2020. The one-year delay over AG scenarios increases the maximum statutory penalties by $65,813,000.

For the NO scenarios, PREPA assumed that the Project is not pursued and only a new Combined Cycle is constructed by January 1, 2024, to replace the Aguirre units 1&2 boilers. The 2024 timeframe reflects PREPA's experience with the Prevention of Significant Deterioration (PSD) permitting process for the San Juan Combined Cycle units 5 and 6 and the typical engineering, design, procurement and construction of new combined cycle units. This estimate does not consider other additional data-gathering period or efforts required for the permit application to EPA or additional delays due to legal challenges to the permitting process. Another issue for consideration is that Section 505(c) of the Puerto Rico Oversight, Management and Economic Stability Act (PROMESA) states that "All reviews conducted and actions taken by any Federal agency relating to a Critical Project shall be expedited in a manner consistent with completion of the necessary reviews and approvals by the deadlines under the Expedited Permitting Process, but in no way shall the deadlines established through the Expedited Permitting Process be binding on any Federal agency." Thus, PROMESA does not require EPA to expedite its PSD permitting processes, which will make this new combined cycle completion date subject to the availability of EPA's personnel at a time when the agency is facing budget cuts. PREPA considered statutory civil penalties to accrue from July 1, 2017 to December 31, 2023 at the same rates as in AG scenarios. As in AG scenarios, PREPA also considered dates when generating units are scheduled to be out of service due to programmed maintenance or environmental outages. PREPA estimates the maximum statutory civil penalties under NO scenarios at $408,563,000 for the period from July 1, 2017, to December 31, 2023. NO scenarios results in maximum statutory penalties $325,407,000 greater than those of AG scenarios.

Any decision regarding the AOGP will certainly have an impact on PREPA's compliance efforts in other MATS applicable generating units, such as the San Juan 9&10 and Palo Seco 3&4. If the Commission disapproves construction of AOGP and the conversion of the Aguirre units, a delay in MATS compliance in San Juan and Palo Seco are expected, which entails the exposure to additional and unnecessary civil penalties.

For AG scenarios, PREPA assumed the AOGP Project to be completed by April 1, 2019, which reflects the earliest expected online date, and that the San Juan units 9 & 10 could be retired by December 31, 2022. PREPA considered statutory civil penalties to accrue from July 1, 2017, to December 31, 2022 at the same rates as in for Aguirre units, as well as the dates when generating units are scheduled to be out of service due to programmed maintenance or environmental outages. PREPA estimates the maximum statutory civil penalties under for the San Juan generating units at $336,098,000 for the period from July 1, 2017, to December 31, 2022.

For the NO Scenarios, PREPA assumed that the San Juan units 9 & 10 could be retired by December 31, 2021. PREPA considered statutory civil penalties to accrue from July 1, 2017 to December 31, 2021, at the same rates as in AG scenarios, as well as the dates when generating units are scheduled to be out of service due to programmed maintenance or environmental outages. PREPA estimates the maximum statutory civil penalties under the NO Scenarios for the San Juan generating units at $269,625,000 for the period from July 1, 2017, to December 31, 2021.

For AG Scenarios, PREPA assumed that the Palo Seco units 3 & 4 could be retired or declared as limited-use liquid oil-fired EGU's under MATS by December 31, 2022. PREPA considered statutory civil penalties to accrue from July 1, 2017, to December 31, 2022 at the same rates for the Aguirre and San Juan units, as well as the dates when generating units are scheduled to be out of service due to programmed maintenance or environmental outages. PREPA estimates the maximum statutory civil penalties for the Palo Seco generating units at $326,156,000 for the period from July 1, 2017, to December 31, 2022.

For NO scenarios, PREPA assumed and that the Palo Seco units 3&4 could be retired by December 31, 2023. PREPA considered statutory civil penalties to accrue from July 1, 2017 to December 31, 2023, at the same rates as in AG scenarios, as well as the dates when generating units are scheduled to be out of service due to programmed maintenance or environmental outages. PREPA estimates the maximum statutory civil penalties under the NO scenarios for the Palo Seco generating units at $384,281,000 for the period from July 1, 2017, to December 31, 2023.

The following table summarizes the results obtained from the above referenced analysis:

Table 7-1: Summary of Civil Penalties

Generating Unit	AG Scenarios	One-Year AOGP Delay	NO Scenarios
San Juan 9&10	$336,098,000	$336,098,000	$269,625,000
Palo Seco 3&4	$326,156,000	$326,156,000	$384,281,000
Aguirre 1&2	$83,156,000	$148,969,000	$408,563,000
TOTAL	$745,410,000	$811,223,000	$1,062,469,000

The results obtained show that if the Commission disapproves the AOGP Project (conversions of Aguirre boilers 1&2 and Combined Cycle units, as well as the AOGP construction), PREPA will be exposed to unnecessary and additional civil penalties due to the delays forecasted in MATS compliance for the Aguirre, San Juan and Palo Seco generating units. Based on the economic analysis results, such additional penalties will accrue to $317,059,000.

Section
8

Economic Analysis and Results

This section provides schedules for the AG and NO Cases, and cost results for each of the twelve scenarios required by the Commission, as shown in Table 1-1.

The production costs of all scenarios were obtained using the PROMOD IV® software. This software incorporates extensive details in generating unit operating characteristics, and transmission grid topology and constraints. PROMOD IV® performs a security constrained unit commitment and economic dispatch that is optimized with operating reserve requirements. PROMOD IV® is the tool that PREPA uses to analyze the expected operation of its generating fleet and purchased power.

8.1 AG – Updated P3MF1M

The AOGP costs used in the AG and AG+RE scenarios were the following:

Table 8-1: Aguirre Gas Port Costs

Capital Costs (thousand $2015)	382,643
O&M Costs Annuity	77,406
Conversions (thousand $2015)	
Combined Cycle Units	46,638
Aguirre Steam Units	87,490

8.1.1 Schedules and New Generation Resources for AG Scenarios

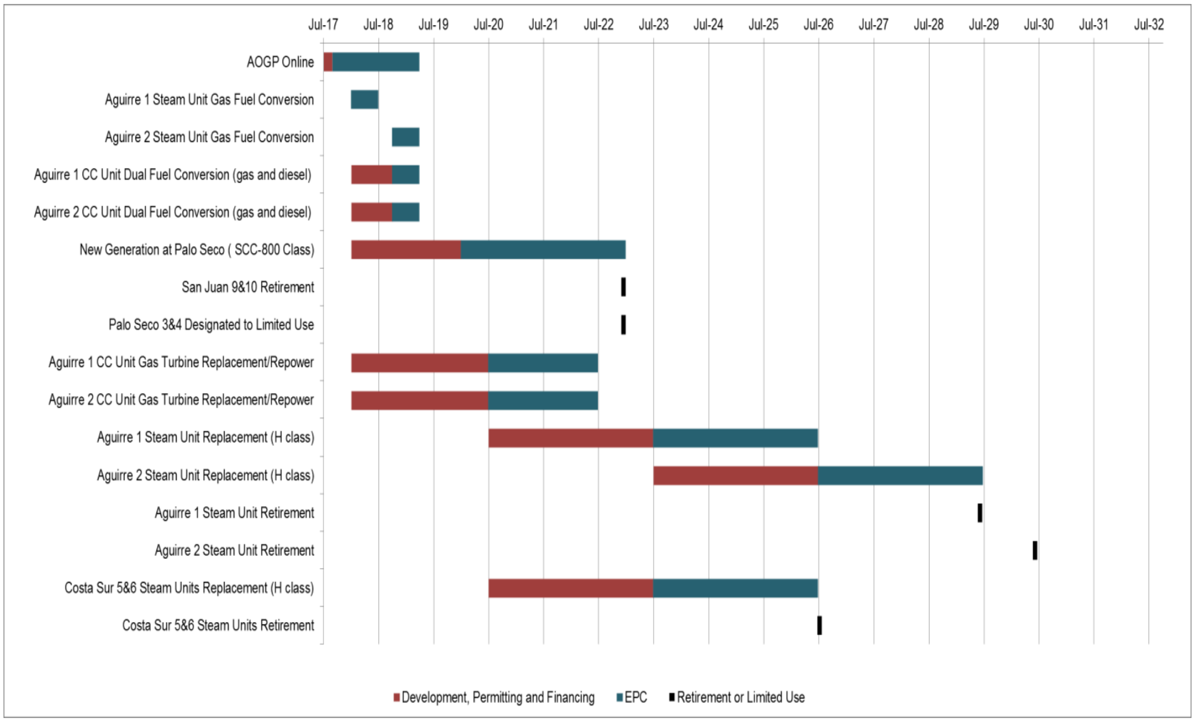
In AG, the new generation resources were obtained from the Supplemental IRP's P3MF1M scenario. The schedule was updated to consider changes in the start date of some of the projects. Considering the schedule update, the repowering of the Aguirre CC units is fully operational by July 1, 2022. As in the P3MF1M scenario, four (4) new generation resources are added in AG. A timeline indicating key portfolio retirement, fuel switching, and new build schedules is presented in Figure 8-1. As a result, AG incurs in total capital costs of $3,368 million during the 2018-2037 study period. The new fossil fueled generation resources include:

- SCC-800 (or similar competing model) 1X1 CC with diesel as primary fuel at Palo Seco by January 1, 2023;
- H Class (or similar competing model) 1X1 CC with natural gas as primary fuel at Costa Sur by July 1, 2026;

- H Class (or similar competing model) 1X1 CC with natural gas as primary fuel at Aguirre by July 1, 2026; and
- H Class (or similar competing model) 1X1 CC with natural gas as primary fuel at Aguirre by July 1, 2029.

Costa Sur 5&6 steam units are scheduled to be retired by July 1, 2026, while Aguirre 1&2 steam units by July 1, 2030 and July 1, 2029, respectively.

Figure 8-1: AG Schedules



Note: San Juan steam units 9&10 and Palo Seco steam units 3&4 will be retired or designated as limited use.

8.1.2 AG Fuel Prices Forecast Scenarios

As required on the Commission's February 10, 2017 order, PREPA conducted an assessment of the impact of several fuel prices forecasts. The fuel prices forecasts include Reference, High Oil Price and Low Oil Price cases based on the Energy Information Administration's 2017 edition of the Annual Energy Outlook. The fuel prices forecasts are presented in Appendix D-6.

The analysis considered the same new generation resources for Reference, High Oil Price and Low Oil Price cases for the AG scenarios.

8.1.2.1 AG Base Fuel Price Forecast Scenario (AG_Base)

The present value of system costs in the AG_Base scenario aggregates to $27.97 billion over the 2018-2037 forecast period. AG_Base system costs average $2.65 billion per year over the forecast period.

8.1.2.2 AG High Oil Fuel Price Forecast Scenario (AG_High_Oil)

AG_High_Oil fuel case resulted in a present value of system costs of $32.23 billion over the 2018-2037 period. This is approximately $4.26 billion higher than the AG_Base with the reference fuel forecast. System costs average $2.93 billion per year over the forecast period, which is about $279 million higher than the base case. These increases are driven by the substantially higher fuel forecast assumed in this high oil case for the analysis.

8.1.2.3 AG Low Oil Fuel Price Forecast Scenario (AG_Low_Oil)

AG_Low_Oil case resulted in a present value of system costs of $26.04 billion, which is approximately $1.93 billion lower than the AG_Base with the reference fuel forecast. System costs average $2.48 billion per year over the forecast period, which is about $168 million lower than the base case. The reductions are driven by the substantially lower fuel forecast assumed in the low oil case for the analysis.

Table 8-2: AG Cases System Costs Summary

System Costs	Unit	AG_Base	AG_High_Oil	AG_Low_Oil
Total Present Value of System Costs	*$ 000*	27,966,466	32,229,507	26,035,505
Average Annual System Costs	*$ 000*	2,649,347	2,928,039	2,481,667
Difference in Present Value of Systems Costs with AG Base	*$ 000*	0	4,263,041	-1,930,961
Difference in Average Annual System Costs with AG Base	*$ 000*	0	278,692	-167,680

8.1.3 Results Comments

The difference in total present value of system costs for the forecast period of 2018 to 2037 between the AG_Base scenario and the AG_High_Oil and AG_Low_Oil scenarios ranged from $4.26 billion higher to $1.93 billion lower, respectively, due to the substantial differences in the fuel prices forecasts.

8.2 AG+RE - Updated P3MF1M_S4

8.2.1 Schedules and New Generation Resources

In AG+RE, which is a demand response case with full target RPS compliance, the fossil fuel new resource decisions are the same as AG, but with increased renewable generation to achieve full target RPS compliance by 2020. In this case, AOGP is built, there is an energy efficiency demand reduction, full target RPS compliance is required by 2020 and a demand response program is implemented.

8.2.2 AG+RE Fuel Prices Forecast Scenarios

8.2.2.1 AG+RE Base Fuel Price Forecast Scenario (AG+RE_Base)

The present value of system costs for AG+RE_Base aggregates to $29.65 billion over the 2018-2037 forecast period. System costs average $2.74 billion per year over the forecast period.

The present value of the system costs of $29.65 billion is about $1.68 billion higher than the corresponding value for the case with a reduced RPS target and without demand response (AG_Base case with a present value of system costs of $27.97 billion).

8.2.2.2 AG+RE High Oil Fuel Price Forecast Scenario (AG+RE_High_Oil)

AG+RE_High_Oil resulted in a present value of system costs of $32.45 billion, which is approximately $2.8 billion higher than the AG+RE_Base with base fuel forecast, driven by the substantially higher fuel forecast assumed in the fuel sensitivity analysis.

The present value of the system costs is about $221 million higher than the corresponding value for the case with a reduced RPS target and without demand response (AG_High_Oil case with a present value of system costs of $32.23 billion).

8.2.2.3 AG+RE Low Oil Fuel Price Forecast Scenario (AG+RE_Low_Oil)

AG+RE_Low_Oil resulted in a present value of system costs of $26.93 billion, which is approximately $2.72 billion lower than the AG+RE_Base with base fuel forecast, driven by the substantially lower fuel forecast assumed in the fuel sensitivity analysis.

The present value of the system costs is about $890 million higher than the corresponding value for the case with a reduced RPS target and without demand response t (AG_Low_Oil case with a present value of system costs of $26.04 billion).

Table 8-3: AG+RE Cases System Costs Summary

System Costs	Unit	AG+RE_Base	AG+RE_High_Oil	AG+RE_Low_Oil
Total Present Value of System Costs	*$ 000*	29,650,010	32,450,987	26,925,712
Average Annual System Costs	*$ 000*	2,736,924	2,955,521	2,544,515
Difference in Present Value of Systems Costs with AG+RE Base	*$ 000*	0	2,800,977	-2,724,298
Difference in Average Annual System Costs with AG+RE Base	*$ 000*	0	218,597	-192,409

Table 8-4: AG+RE Cases System Costs Comparison with AG Cases

System Costs	Unit	AG_Base	AG_High_Oil	AG_Low_Oil
Total Present Value of System Costs	*$ 000*	27,966,466	32,229,507	26,035,505
Average Annual System Costs	*$ 000*	2,649,347	2,928,039	2,481,667

System Costs	Unit	AG+RE_Base	AG+RE_High_Oil	AG+RE_Low_Oil
Total Present Value of System Costs	*$ 000*	29,650,010	32,450,987	26,925,712
Average Annual System Costs	*$ 000*	2,736,924	2,955,521	2,544,515
Difference in Present Value of Systems Costs with AG Base	*$ 000*	1,683,543	221,480	890,206

8.2.3 Results Comments

AG+RE evaluates the impacts of full target RPS compliance aided by a demand response program. The impact of fuel prices have similar tendencies as the results presented above for AG, with significant differences in the total present value of system costs among AG+RE_Base and the AG+RE_High_Oil and the AG+RE_Low_Oil scenarios ranging from $2.8 billion higher to $2.7 billion lower respectively.

AG+RE scenarios resulted in higher system costs than AG scenarios. This is primarily due to two reasons: (1) the cheaper conventional generation is replaced by PV generation which has a higher price; and (2) an estimated cost of 2 cents per kWh for the control systems to shift from the night peak to the mid-day.

8.3 NO - Updated P3MF2M

8.3.1 Schedules and New Generation Resources

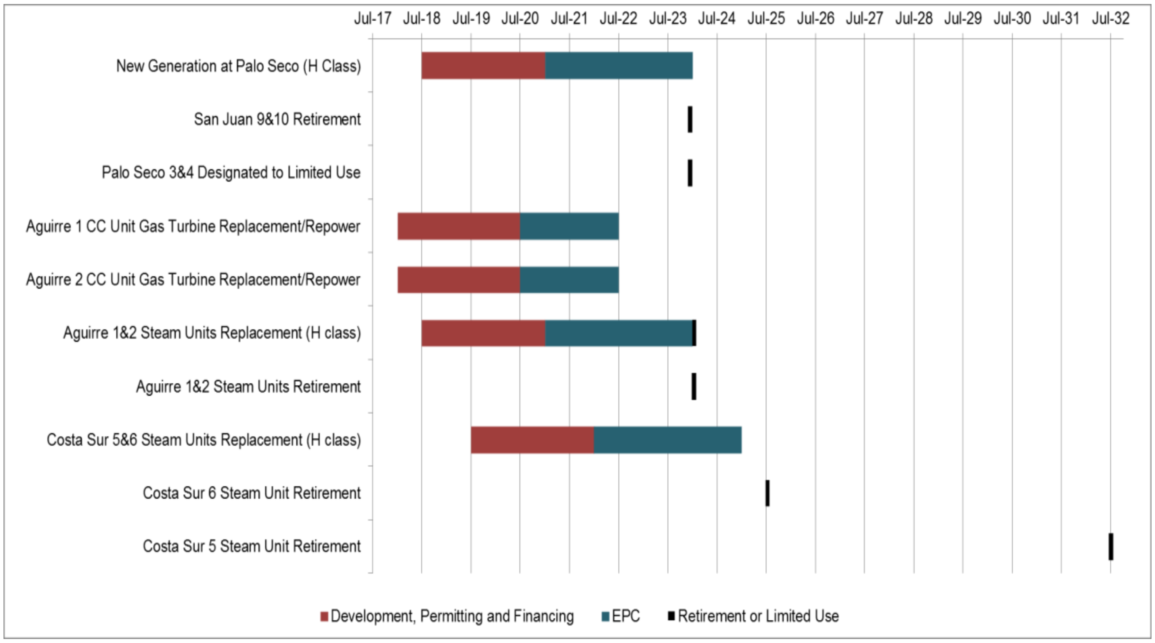
NO corresponds to the P3MF2M scenario of the Supplemental IRP, including some updates. In these cases AOGP is not built, there is no gas at Aguirre power plant, and Aguirre steam units1&2 must be retired in an accelerated manner due to MATS compliance.

The Aguirre 1&2 CC units repowering are scheduled to be in operation by July 1, 2022. As in the P3MF2M scenario, three new generation resources are added. A timeline indicating key portfolio retirement, fuel switching, and new build schedules is presented in Figure 8-2. As a result, NO incurs total capital costs of $2,797 million during 2018-2037. The portfolio capital cost requirements are $2,642 million during 2018-2025 and $155 million during 2026-2037. The new resources include:

- H Class (or similar competing model) 1X1 CC with diesel as primary fuel at Palo Seco by January 1, 2024;
- H Class (or similar competing model) 1X1 CC with diesel as primary fuel at Aguirre by January 1, 2024; and
- H Class (or similar competing model) 1X1 CC with natural gas as primary fuel at Costa Sur by January 1, 2025.

Aguirre 1&2 steam units will be retired by December 31, 2023, while Costa Sur 6&5 steam units can be retired by July 1, 2025, and July 1, 2032, respectively.

Figure 8-2: NO Schedules



Note: San Juan steam units 9&10 and Palo Seco steam units 3&4 will be retired or designated as limited use.

Table 8-5: Capital Cost Comparison AG and NO Scenarios

Capital Costs	Unit	AG Scenarios	NO Scenarios
FY 2018 - 2025 Total Capital Costs	*$ million*	2,357	2,642
FY 2026 - 2037 Total Capital Costs	*$ million*	1,011	155
FY 2018 - 2037 Total Capital Costs	*$ million*	3,368	2,797

Capital Costs	Unit	AG Scenarios	NO Scenarios
Generation	*$ million*	1,453	1,365
Fuel Infrastructure	*$ million*	370	0
Transmission	*$ million*	1,545	1,433
Total	*$ million*	3,368	2,798

8.3.2 NO Fuel Prices Forecast Scenarios

PREPA assumed the same new generation resources for Reference, High Oil Price, and Low Oil Price cases for the NO scenarios.

8.3.2.1 NO Base Fuel Price Forecast Scenario (NO_Base)

The present value of system costs in NO_Base scenario aggregates to $31.38 billion over the 2018-2037 study period. System costs average $2.95 billion per year over the forecast period.

The key finding in this case is that the present value of the system costs of $31.38 billion is about $3.42 billion higher than the corresponding value for the case that AOGP is built

(AG_Base case with a present value of system costs of $27.97 billion), thus demonstrating the value of the AOGP project in the base case, which is the scenario that represents the most likely conditions to occur.

8.3.2.2 NO High Oil Fuel Price Forecast Scenario (NO_High_Oil)

NO_High_Oil fuel case resulted in a present value of system costs of $43.28 billion, which is approximately $11.9 billion higher than the NO_Base with the reference fuel forecast, driven by the substantially higher fuel forecast assumed in the analysis.

The present value of the system costs is about $11.05 billion higher than the corresponding value for the case that the AOGP is built (AG_High_Oil case with a present value of system costs of $32.23 billion), thus resulting in a tremendous economic advantage of the AOGP project in case world oil prices raise to considerably high values.

8.3.2.3 NO Low Oil Fuel Price Forecast Scenario (NO_Low_Oil)

NO_Low_Oil fuel case resulted in a present value of system costs of $24.32 billion, which is approximately $7.07 billion lower than the NO_Base with the reference fuel forecast, driven by the substantially lower fuel forecast assumed in the fuel sensitivity analysis.

When comparing the present value of the system costs of NO_Low_Oil Scenario with the corresponding value of $26.04 of AG_Low_Oil, the costs for NO_Low_Oil Scenario are $1.72 billion lower. In this scenario, world oil prices fall to significantly low figures.

Table 8-6: NO Cases System Costs Summary

System Costs	Unit	NO_Base	NO_High_Oil	NO_Low_Oil
Total Present Value of System Costs	*$ 000*	31,383,572	43,279,669	24,316,491
Average Annual System Costs	*$ 000*	2,952,589	4,054,170	2,328,100
Difference in Present Value of Systems Costs with NO Base	*$ 000*	0	11,896,097	-7,067,081
Difference in Average Annual System Costs with NO Base	*$ 000*	0	1,101,582	-624,489

Table 8-7: NO Cases System Costs Comparison with AG Cases

System Costs	Unit	AG_Base	AG_High_Oil	AG_Low_Oil
Total Present Value of System Costs	*$ 000*	27,966,466	32,229,507	26,035,505
Average Annual System Costs	*$ 000*	2,649,347	2,928,039	2,481,667

System Costs	Unit	NO_Base	NO_High_Oil	NO_Low_Oil
Total Present Value of System Costs	*$ 000*	31,383,572	43,279,669	24,316,491
Average Annual System Costs	*$ 000*	2,952,589	4,054,170	2,328,100
Present Value of Systems Costs Difference with AG Cases	*$ 000*	3,417,106	11,050,162	-1,719,014

8.3.3 Results Comments

The difference in total present value of system costs for the forecast period of 2018 to 2037 among the NO_Base scenario and the NO_High_Oil and NO_Low_Oil scenarios ranged from approximately $11.9 billion higher to $7.1 billion lower respectively due to the substantial differences in the fuel prices forecasts.

The comparison of the base scenario, AG_Base (AOGP is built), with the NO_Base (there is no AOGP and no gas available), results in an economic benefit of $3.42 billion for the AOGP project. The conditions assumed in the base scenarios represent the most likely to occur.

The present value of the system costs is about $11.05 billion higher than the corresponding value for the case that AOGP is built (AG_High_Oil case with a present value of system costs of $32.23 billion), thus resulting in a tremendous economic advantage of the AOGP project in case world oil prices raise to considerably high values (in the order of an average price of $240/BBL for Fuel Oil No. 6 and $295/BBL for Fuel Oil No. 2 in the twenty year forecasted period).

When comparing the present value of the system costs of NO_Low_Oil Scenario with the corresponding value of $26.04 of AG_Low_Oil, the NO_Low_Oil scenario costs are about $1.72 billion lower. In this scenario world oil prices fall significantly and remain low during all the study period. The average price for Fuel Oil No. 6 is $30/BBL and at the end of the study period is still lower than $38/BBL. The average price for Fuel Oil No. 2 is $67/BBL and the price is below $93/BBL at the end of the twenty year forecasted period.

8.4 NO+RE

8.4.1 Schedules and New Generation Resources

In NO+RE scenarios, where a demand response program is implemented and increased renewable generation is considered to achieve full target RPS compliance by 2020, the fossil fuel new resource decisions are the same as in NO scenarios. In the NO+RE scenarios the AOGP is not built, and there is no natural gas available in the Aguirre Complex.

8.4.2 NO+RE Fuel Prices Forecast Scenarios

PREPA assumed the same new generation resources for Reference, High Oil Price, and Low Oil Price cases for the NO+RE scenarios.

8.4.2.1 NO+RE Base Fuel Price Forecast Scenario (NO+RE_Base)

The present value of system costs for NO+RE_Base scenario aggregates to $31.95 billion over the 2018-2037 forecast period. System costs average to approximately $3 billion per year over the forecast period.

The present value of the system costs of $31.95 billion is about $570 million higher than the corresponding value for the case with a reduced RPS target and without demand response (NO_Base case with a present value of system costs of $31.38 billion).

The present value of the system costs is about $2.3 billion higher than the corresponding value for the case that AOGP is built (AG+RE_Base case with a present value of system costs of $29.65 billion), thus the results favor the AOGP project.

8.4.2.2 NO+RE High Oil Fuel Price Forecast Scenario (NO+RE_High_Oil)

NO+RE_High_Oil fuel case resulted in a present value of system costs of $42.93 billion, which is approximately $10.98 billion higher than the NO+RE_Base with the reference fuel forecast, driven by the substantially higher fuel forecast assumed in the analysis.

The present value of the system costs of $42.93 billion is about $349 million lower than the corresponding value for the case with a reduced RPS target and without demand response (NO_High_Oil case with a present value of system costs of $43.28 billion).

The present value of the system costs is about $10.48 billion higher than the corresponding value for the case that AOGP is built (AG+RE_High_Oil case with a present value of system costs of $32.45 billion), thus demonstrating the significant advantage of the AOGP project in case world oil prices raise to considerably high values (in the order of an average price of $240/BBL for Fuel Oil No. 6 and $295/BBL for Fuel Oil No. 2 in the twenty year forecasted period).

8.4.2.3 NO+RE Low Oil Fuel Price Forecast Scenario (NO+RE_Low_Oil)

NO+RE_Low_Oil fuel case resulted in a present value of system costs of $25.27 billion, which is approximately $6.68 billion lower than the NO+RE_Base with the reference fuel forecast, driven by the substantially lower fuel forecast assumed in the analysis.

The present value of the system costs of $25.27 billion is about $956 million higher than the corresponding value for the case with a reduced RPS target and without demand response (NO_Low_Oil case with a present value of system costs of $24.32 billion).

The present value of the system costs is about $1.65 billion lower than the corresponding value for the case that AOGP is built (AG+RE_Low_Oil case with a present value of system costs of $26.93 billion).

Table 8-8: NO+RE Cases System Costs Summary

System Costs	Unit	NO+RE_Base	NO+RE_High_Oil	NO+RE_Low_Oil
Total Present Value of System Costs	*$ 000*	31,953,470	42,930,765	25,272,220
Average Annual System Costs	*$ 000*	2,998,661	4,012,819	2,397,073
Difference in Present Value of Systems Costs with NO+RE Base	*$ 000*	0	10,977,295	-6,681,250

Table 8-9: NO+RE Cases System Costs Comparison with NO Cases

System Costs	Unit	NO_Base	NO_High_Oil	NO_Low_Oil
Total Present Value of System Costs	*$ 000*	31,383,572	43,279,669	24,316,491
Average Annual System Costs	*$ 000*	2,952,589	4,054,170	2,328,100

System Costs	Unit	NO+RE_Base	NO+RE_High_Oil	NO+RE_Low_Oil
Total Present Value of System Costs	*$ 000*	31,953,470	42,930,765	25,272,220
Average Annual System Costs	*$ 000*	2,998,661	4,012,819	2,397,073
Difference in Present Value of Systems Costs with NO Cases	*$ 000*	569,898	-348,903	955,729

Table 8-10: NO+RE Cases System Costs Comparison with AG+RE Cases

System Costs	Unit	AG+RE_Base	AG+RE_High_Oil	AG+RE_Low_Oil
Total Present Value of System Costs	*$ 000*	29,650,010	32,450,987	26,925,712
Average Annual System Costs	*$ 000*	2,736,924	2,955,521	2,544,515

System Costs	Unit	NO+RE_Base	NO+RE_High_Oil	NO+RE_Low_Oil
Total Present Value of System Costs	*$ 000*	31,953,470	42,930,765	25,272,220
Average Annual System Costs	*$ 000*	2,998,661	4,012,819	2,397,073
Present Value of Systems Costs Difference with AG+RE Cases	*$ 000*	2,303,460	10,479,779	-1,653,491

8.4.3 Results Comments

The difference in total present value of system costs for the study period of 2018 to 2037 between the NO+RE_Base scenario and the NO+RE_High_Oil and NO+RE_Low_Oil scenarios ranged from approximately $11 billion higher to $6.7 billion lower, respectively, due to the substantial differences in the fuel prices forecasts.

NO+RE_Base and NO+RE_Low_Oil scenarios resulted in total value of system costs higher than the corresponding NO scenarios, but NO+RE_High Oil scenario resulted in lower total present value of system costs than NO_High_Oil scenario. The reasons for higher costs in NO+RE_Base and NO+RE_Low_Oil are: (1) the cheaper conventional generation is replaced by PV generation which has a higher price; and (2) an estimated cost of 2 cents per kWh for the control systems to shift from the night peak to the mid-day. In the NO+RE_High Oil scenario,due to the high fuel prices, the cost of the renewable generation becomes lower than the cost of conventional generation.

The comparison of the base scenario, AG+RE_Base (AOGP is built) with the base case NO+RE_Base (no AOGP and no gas), results in an economic benefit of $2.3 billion for the AOGP project. The conditions assumed in the base scenarios represent the most likely to occur.

The present value of the system costs is about $10.5 billion higher than the corresponding value for the case that the AOGP is built (AG+RE_High_Oil case with a present value of system costs of $32.45 billion), thus resulting in a tremendous economic advantage of the AOGP project in case world oil prices raise to considerably high values.

When comparing the present value of the system costs of NO+RE_Low_Oil Scenario with the corresponding value of $26.9 of AG+RE_Low_Oil, the costs for the NO+RE_Low_Oil scenario are $1.65 billion lower. In this scenario world oil prices fall significantly and remain low during the twenty year study period. The average price for Fuel Oil No. 6 is $30/BBL and at the end of the study period is still lower than $38/BBL. The average price for Fuel Oil No. 2 is $67/BBL and the price is below $93/BBL at the end of the twenty year forecasted period.

8.5 AG Scenario with AOGP One Year Delay

PREPA estimates April 2019 as the earliest expected date for the Aguirre Offshore Gasport to be constructed and fully operational, in view of the current permitting process status. In its order, the Commission requested evaluating the alternative of a one-year delay for AOGP from the earliest expected online date. PREPA performed simulations using PROMOD IV® to evaluate the effect of such delay. The AG_Base was used as the base case, but AOGP's commissioning date was extended to April 2020. The reference fuel projection was used to complete this simulation with a one-year delay in the commissioning of AOGP to compare between cases (AG_Base, NO_Base and AG_Base Delay).

The results obtained show that AOGP is the most feasible and economically viable project to comply with MATS and shift from the current fuel oil dependency, as well as keeping fuel costs stable. The AG_Base Delayed case has a present value of system cost of approximately $186 million dollars higher than the AG_Base Reference case, but it is still much lower than the NO_Base case by a difference of more than $ 3.2 billion dollars. The results of this simulation show that, even with a one-year delay, having AOGP in operation and converting Aguirre steam units 1 & 2 result in the more beneficial option for the citizens of Puerto Rico rather than disapproving the Project and beginning the construction of new combined cycles units using light distillate as fuel. The following tables show the present value of system costs for the compared cases:

Table 8-11: AG_Base Delay Cases System Costs Comparison with AG_Base

System Costs	Unit	AG_Base	AG_Base Delay
Total Present Value of System Costs	*$ 000*	27,966,466	28,152,479
Difference in Present Value of Systems Costs with AG_Base	*$ 000*	0	186,013

Table 8-12: AG_Base Delay Cases System Costs Comparison with NO_Base

System Costs	Unit	NO_Base	AG_Base Delay
Total Present Value of System Costs	*$ 000*	31,383,572	28,152,479
Difference in Present Value of Systems Costs with NO_Base	*$ 000*	0	-3,231,093

8.5.1 Results Comments

When comparing the difference between the AG_Base reference case and the AG_Base Delay case, there are two major contributors: fuel costs and exposure to civil penalties. The effect of the maximum statutory civil penalties under the Clean Air Act for the Aguirre Complex due to one-year delay in the operation of the AOGP entails an additional cost of $66 million. The fuel consumption portion entails an increase of approximately $80 million due to the delay in the AOGP operation by April 2020 (FY 2020 values).

The comparison between the AG_Base Delay case and the NO_Base case (no AOGP) show the same contributors to the costs difference than the comparison with the AG_Base case. The fuel savings with the case considering the delay on AOGP are significant when compared with the case where the AOGP is not built. The same behavior is expected with the civil penalties, which PREPA could face for non-compliance with MATS.

Based on the evaluation results obtained and detailed above, it is concluded that AOGP is the most cost effective and expedited option to comply with MATS. The AOGP Project will also stabilize fuel costs and thus the electricity bills, providing for the use of a much cleaner fuel that is projected to remain stable (availability and price) in the long term. This analysis demonstrated that, even delaying the project by one year, it is economically feasible for PREPA and the People of Puerto Rico to achieve environmental compliance, provide environmental justice, and electricity price stabilization that will help to improve Puerto Rico's economic situation.

Appendixes