SECRETARIA
COMISION DE ENERGIA DE
PUERTO RICO

COMMONWEALTH OF PUERTO RICO

PUERTO RICO ENERGY BUREAU

'18 SEP 11 P1:1?

IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN	NO. CEPR-AP-2018-0001 **SUBJECT:** PREPA'S MOTION FOR EXPEDITED CLARIFICATION OF CERTAIN ASPECTS OF THE ENERGY BUREAU'S RESOLUTION AND ORDER OF SEPTEMBER 5, 2018

PREPA'S MOTION FOR EXPEDITED CLARIFICATION OF CERTAIN ASPECTS OF THE ENERGY BUREAU's <u>RESOLUTION AND ORDER OF SEPTEMBER 5, 2018</u>

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COMES NOW the Puerto Rico Electric Power Authority ("PREPA") and respectfully requests that the honorable Puerto Rico Energy Bureau (the "Bureau") provide expedited clarification of certain technical aspects of the Bureau's Resolution and Order of September 5, 2018 ("September 5th order). PREPA respectfully requests that the Bureau, consistent with applicable procedural requirements and as soon as practically possible: (1) set up a formal or informal technical call between Bureau personnel / advisors and PREPA and Siemens Industry personnel working on the next PREPA Integrated Resource Plan ("IRP") in order to resolve the clarification items; and/or (2) respond in writing to the items. All else being equal, PREPA strongly believes that a call would be the best process to quickly and unambiguously resolve these technical items, because a call allows for immediate follow-up and closure on and confirmation of mutual understandings. In support of its Motion, PREPA states further as follows.

1. The in-progress IRP is intended to serve important purposes relating to the restructuring and transformation of PREPA and the Puerto Rico electric sector as well as serving as the next IRP in the process contemplated by statute and the Bureau's IRP regulation (No. 9021) as required by the Bureau's past orders, as PREPA has discussed in various past filings.

2. PREPA continues to have the objectives of preparing a proper and useful IRP as soon as practical that is consistent with good practices, fits the unique situation facing PREPA and Puerto Rico, and meets applicable requirements.

3. The September 5th order directs certain significant additions and/or changes in PREPA's design and performance of the IRP, especially relating to scenarios.

4. However, as explained and illustrated further in the attachments to this Motion, PREPA needs certain technical clarifications of the September 5th order so that PREPA can meet the objectives and requirements of the IRP in as timely a manner as possible while complying with the September 5th order.

5. PREPA asks for expedited resolution of the clarification items because the IRP serves purposes relating to the restructuring and transformation of PREPA and the electric sector, as noted above, because the timeline for the IRP is expedited for reasons discussed in past orders and filings, and because the clarification items will have an effect on the timeline for the IRP, especially the longer they remain unresolved.

6. PREPA defers to the Bureau on what appropriate specific process will most swiftly and correctly resolve the clarification items, but, all else being equal, PREPA strongly prefers a call as explained in the introduction of this Motion.

7. The clarification items are set forth in Attachment 1 hereto, which has been prepared by Siemens Industry in consultation with PREPA.

8. There also are three documents attached in ".pdf" form to this Motion. The other attachments are referenced in and support / explain / illustrate Attachment 1.

WHEREFORE, the Puerto Rico Electric Power Authority respectfully requests that the honorable Puerto Rico Energy Bureau grant this Motion and set up an expedited technical call or other suitable expedited process to resolve the technical clarification items.

RESPECTFULLY SUBMITTED,

IN SAN JUAN, PUERTO RICO, THIS 10th DAY OF SEPTEMBER, 2018

PUERTO RICO ELECTRIC POWER AUTHORITY

Nitza D. Vázquez Rodríguez
TSPR No. 9311
Senior Attorney
Puerto Rico Electric Power Authority
P.O. Box 363928
San Juan, Puerto Rico 00936-3928
Tel. 787-521-4499
Email: n-vazquez@aeepr.com

CERTIFICATION OF FILING AND SERVICE

I hereby certify that on September 10, 2018, I have sent the above Motion (including its attachments) to the Puerto Rico Energy Bureau through its Clerk via email to secretaria@energia.pr.gov and mcintron@energia.pr.gov; and to the office of the Bureau's internal legal counsel via email to legal@energia.pr.gov and sugarte@energia.pr.gov.

Nitza D. Vázquez Rodríguez
TSPR No. 9311
Senior Attorney
Puerto Rico Electric Power Authority
P.O. Box 363928
San Juan, Puerto Rico 00936-3928
Tel. 787-521-4499
Email: n-vazquez@aeepr.com

Siemens Industry, in consultation with PREPA, reviewed the Energy Bureau (EB) Resolution and Order of September 5, 2018 ("Order"), on new scenarios and related items and would like to seek clarification on some important items before Siemens and PREPA proceed to the formulation of the revised scenarios. PREPA and its advisors seek a call with EB personnel / advisors clarify these issues, and be able to comply fully with the request, and avoid misunderstandings, extra costs, and delays.

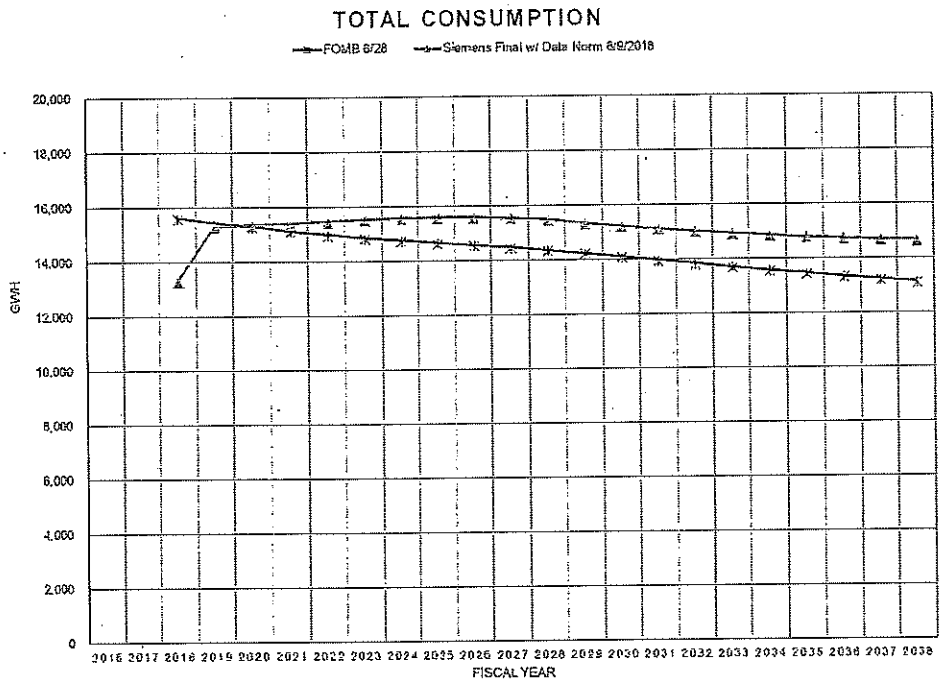
1- The Energy Bureau (EB) references in its Order the IRP Regulation and in particular Section 2.03 F (3) e. PREPA provided the Energy Bureau, for its information and subsequent approval, our assessment of programs that have the greatest likelihood of success in Puerto Rico, but this fall short of the 2% per year reduction for 10 years. Please find attached an updated latest version of the memorandum. Is the Energy Bureau expectation that PREPA shall include the 2% per year reduction instead of our forecast on all Scenarios (the new ordered and the ones already proposed by PREPA), or only on the new Scenarios Ordered (except for the Low EE case)?

2- Please note that, for the Energy Bureau mandated EE forecast (e.g., 2% YOY for 10 years), we intend to scale up the costs of the program identified, basically assuming larger participation.

3- With respect of Demand Response, our updated forecast reaches approximately 1.8% of the peak of the served load peak by 2021 and by 2027 reaches 3%. This program continues to grow, while the load is declining and by 2038 represents 3.8%. By 2025 DR represents 2.4% of the peak demand. With this revised forecast, should we use our projections for which we have a cost and a rationale?

4- It should be noted that we are modeling the effect of Demand Response as fast responsive reserves. That is a resource available to operators to complement the spinning reserve requirements and avoid the need to bring online expensive combustion turbines as well postponing / eliminating the need for new peaking units. Therefore, DR is currently being modeled as reserve not a reduction on the peak. Is that acceptable, or does the EB intend for other effects to be modeled in the added cases, or in all the cases?

5- The Energy Bureau requests that PREPA to use as the reference case the FOMB base forecast. However, we would like to clarify that our reference case base forecast uses the same underlying assumptions as the FOMB forecast and the only difference is the way the model was created as our model is based on normalized monthly values (normalization filter volatility introduced by billing), instead of yearly values. Also, the FOMB forecast includes the effect of DG and EE that our forecast treats separately. The attached memorandum provides an update on our forecast and it was extensively discussed with the FOMB. The graph below shows a comparison between or base case and the FOMB projection (before EE and DG). As a reference, our forecast by 2025 is 6% higher than FOMB and by 2038 11% higher. Considering the above, should PREPA switch its Base Case to the FOMB base case? Are we to use this different load forecast in all cases/scenarios?



6- With respect of the high and low load forecast, there are two approaches. We intend to use stochastics to identify the 25 and 75 percentile projections and provide generic explanation of what would need to happen in the PR economy for this to occur (see attached report for details on explanatory variables for the high and low case). Alternatively, we could use the highest GNP forecast we have (Moody's) and the slower population decline (US Census) to produce the high case. For the low case we could use Moody's population forecast (most pessimistic) and for the GNP we could use FOMB to 2018 and continue declining the IMF decline rate from this moment onwards. We favor the first approach but would like to confirm the Energy Bureau position. The final base, high, and low load forecasts will be used for all scenarios. Is that acceptable?

7- Our forecast is based on creating a model that correlates the observed change in sales with the exogenous variables (GNP, population, weather, etc.). In as much as the history includes the effect of naturally occurring EE and changes in construction, these are included in the forecast. There is no other adjustment beyond those explicitly model externally. In our opinion this should is adequate for the purposes of the IRP. Is that acceptable?

8- PREPA intends to determine the Long-Term Capacity Expansion plan for each scenario / strategy for Base, High, and Low load forecast cases. That will allow forming opinion on impacts and decision points and possibly modify the Base Case Long-Term Capacity Expansion plan. In addition, we propose to run a risk analysis with 200 iterations to assess impacts of load, fuel, and DER penetration on the Base Capacity Expansion Plan as modified from the analysis above. Detailed PROMOD analysis will also be carried out on this modified Capacity Expansion Plan and well as transmission system analysis (for selected years) and Base Case load forecast. If that is acceptable to the Energy Bureau, it would allow combining the Energy Bureau Scenario 3 (base load Forecast), Scenario 5 (high load forecast) and Scenario 7 (low load forecast). In addition to the above, the Energy Bureau Scenario 4 (base load Forecast) could be combined with Scenario

5 (high load forecast) and this analysis could also include Scenario 4 but with low load forecast. Is that consolidation of scenarios acceptable?

9- In connection to the above, does the Energy Bureau requires the 200 iterations risk analysis to be ran for the new scenarios ordered, or to limit the analysis to specifically the load, and fuel prices set?

10- The Energy Bureau indicates that: "All" fossil options to include properly-costed AOGP and larger "H" class combined cycle alternatives offered as resource options to the model". Does that apply only to the Energy Bureau Scenarios 1 & 2 or does this also include PREPA's Scenarios 2, 3 ,and 4 that consider other gas sources instead of the AOGP? Will the EB Scenarios 1 and 2 include a sensitivity for a floating LNG platform in San Juan, instead of the LNG land terminal?

11- Does the Energy Bureau intend for Scenarios 1 & 2 to consider in addition to the AOGP, the availability of gas at Yabucoa, Mayaguez, and San Juan in line with PREPA's Scenario 3 & 4?

12- Does the alternative of a large H Class combined cycle units to be considered on all scenarios including those proposed by PREPA? Note that the H Class has a maximum duct fired capacity of 368/ 393 MW (normal/ duct fired). and the F-Class units already in our plan have a maximum capacity of 303 /369 MW (normal/ duct fired). PREPA understands that it is preferred to move away from such large units, due to increased reserve requirements and less flexibility implied by such unit sizes.

13- The Energy Bureau indicates that "All scenarios to include wind resource offerings at reference cost and availability (onshore coastal and/or inland)". Does that apply to all scenarios including those proposed by PREPA? PREPA always intends to let wind compete with solar resources, but at current and forecast prices, lack of local interest in new wind, relatively cheap solar, and poor wind availability, it seems that wind does not compete, unless a project is forced onto the system.

14- With respect of "PREPA to consider running high gas price sensitivities on other PREPA-determined scenarios.", we intend to evaluate the impact of gas price volatility on the risk analysis section of the IRP across all scenarios/strategies. Does the Energy Bureau wish to see in lieu of this, a discrete scenario(s) to be assessed and with high fossil fuel prices? Does the EB believe that NG prices will diverge upwards and not affect the rest of fossil fuel prices?

15- PREPA prepared a document with our proposal for modeling a base case cost reduction for PV/BEES as well as a low case. Please find it <u>attached</u>. We intend to use this in the study. Note that for PV we intend to use NREL's low case and for BEES our estimation based on multiple sources including Lazard. Is that acceptable?

16- In terms of the Solar PV/BESS quantity availability, is it correct that the Energy Bureau's differentiation of the reference trajectory and high availability case is whether to allow solar PV/BESS to be available for commercial operation in fiscal year 2021? If not, please clarify the difference between Reference Trajectory and High Availability.

17- Does the EB want to run the high fuel price sensitivities over all the existing PREPA Scenarios?

18- PREPA intends the sensitivities (Example Economic Retirement of AES/EcoEléctrica) starting over 1 selected scenario. Does the EB want to run these sensitivities over all the EB Scenarios?

SIEMENS
Ingenuity for Life

MEMO TO: PREPA IRP Team

FROM: Siemens PTI/EBA

DATE: August 20, 2018

SUBJECT: PREPA IRP Solar and Storage Technology Assumptions

This memo documents the key assumptions of solar Photovoltaic (PV) and battery storage resources.

Solar Photovoltaic (PV) Projects

In consideration of Puerto Rico's resources, the IRP assumes utility scale solar for new builds of renewable resources. The cost estimates for utility scale solar PV projects are done through the following steps: 1) Establish baseline solar PV operating and overnight capital costs estimate; 2) Evaluate interconnection and land costs specific to Puerto Rico; 3) Assess construction and financing costs reflecting Puerto Rico specific assumptions; 4) Calculate Levelized Cost of Energy (LCOE) for solar PV in Puerto Rico.

Baseline Operating and Overnight Capital Costs

For step 1, the IRP assumes overnight capital costs and operating costs for utility-scale PV systems consistent with the recently published 2018 Annual Technology Baseline (ATB) by National Renewable Energy Laboratory (NREL) as shown in Exhibit 1. The PV system is representative of one-axis tracking systems with performance and pricing characteristics. The assumptions below do not account for a 1.3 DC-to-AC ratio, otherwise known as inverter loading ratio that is included when calculating the LCOE.

SIEMENS

Ingenuity for life

Exhibit 1: U.S. Utility Scale Solar PV Costs Assumptions

NREL 2018 Annual Technology Baseline (ATB) Mid Case		
Year	Solar PV Overnight Capital Costs $2018/KWdc	Fixed Operating Costs $2018/kW-year (dc)
2018	1,087	9.52
2019	1,046	9.11
2020	984	8.37
2021	933	7.80
2022	923	7.71
2023	912	7.63
2024	901	7.54
2025	891	7.46
2026	880	7.37
2027	870	7.29
2028	859	7.21
2029	849	7.12
2030	838	7.04
2031	831	6.98
2032	824	6.92
2033	817	6.86
2034	809	6.81
2035	802	6.75
2036	795	6.69
2037	788	6.63
2038	780	6.57
2039	773	6.52

NREL 2018 Annual Technology Baseline (ATB) Low Case		
Year	Solar PV Overnight Capital Costs $2018/KWdc	Fixed Operating Costs $2018/kW-year (dc)
2018	960	8.51
2019	912	8.04
2020	870	7.45
2021	833	7.00
2022	810	6.81
2023	786	6.62
2024	763	6.43
2025	739	6.24
2026	715	6.05
2027	692	5.87
2028	668	5.68
2029	645	5.49
2030	621	5.30
2031	611	5.22
2032	600	5.13
2033	590	5.05
2034	581	4.98
2035	565	4.85
2036	552	4.74
2037	538	4.64
2038	525	4.53
2039	512	4.43

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

Interconnection Costs

The NREL benchmark includes the transformation to transmission voltage level (e.g. 115 kV) and a cost of $0.03/Wdc for interconnection costs to the POI and a cost of $263,000 for the interconnecting lines (Gen-Ties) to the POI (based on a 30 MW plant). In the case of PREPA these cost can change significantly, thus we will add the PREPA cost to our estimation and subtract the NREL cost. Exhibit 2 shows the interconnection costs assumed for a solar PV project that includes the expansion of an existing substation with one new bay for the solar PV project, the expansion of the control house and 1 mile of interconnecting line. All unit costs shown were provided by PREPA.

Exhibit 2: Interconnection Costs

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

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

Land Costs

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

Using NREL values a 30 MW project would require an area of 225 acres or 910,543 m^2. Using the land cost provided by PREPA the table below shows our estimation of costs for a 30 MW project. Note that in this table we are subtracting the costs already included in NREL benchmark (0.03 $/Wdc).

Exhibit 3: Land Costs

Land Costs	Unit	Value	Unit Price $/unit	Capital ($ 000)
Area for PV Project	m2	910,544	3	2,732
Cost already included in NREL				1,170
Total land cost				**1,562**

Weighted Average Cost of Capital (WACC)

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

Based on discussions with stakeholders, Siemens will consider future builds to be financed by third parties, assuming PREPA obtain financial backing to contract as a credit-worthy counterparty if and as needed. The IRP also will take into account information on potential FEMA funding if such information is provided in a timely manner and as applicable. In terms of capital availability, we do not have clear guidelines on any capital constraints considerations. Such constraints could be incorporated as information becomes available. Exhibit 4 shows the component assumptions deriving an nominal weighted average cost of capital of 8.50%.

Exhibit 4: Weighted Average Cost of Capital Assumptions

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

Note: The corporate income tax rate is assumed based on a base rate of 20%, plus a graduated surcharge ranging from 5% to 19%[1].

Investment Tax Credit (ITC)

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

Project Development and Construction Time

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

Levelized Cost of Energy (LCOE)

For the IRP modeling, the levelized cost of energy (LCOE) is calculated as the net present value of the unit-cost of energy over the lifetime of the solar PV asset. The LCOE is then used as a proxy for the average price that the solar PV project could break even over its lifetime. Exhibit 5 shows the LCOE of

[1] Deloitte International Tax Puerto Rico Highlights 2018

solar PV under base case and low case. Exhibit 6 shows the other assumptions used in deriving the LCOE. Exhibit 7 and Exhibit 8 show the LCOE calculation for the base case and low case separately.

Exhibit 5: Levelized Cost of Energy (LCOE) of Solar PV

Levelized Cost of Energy in Puerto Rico		
Commercial On Line (COD) Year	Mid Case Solar PV $2018/MWh	Low Case Solar PV $2018/MWh
2018	69	62
2019	67	59
2020	63	56
2021	64	58
2022	67	60
2023	78	68
2024	77	66
2025	76	65
2026	76	63
2027	75	61
2028	74	59
2029	73	57
2030	72	55
2031	72	55
2032	71	54
2033	71	53
2034	70	52
2035	70	51
2036	69	50
2037	68	49
2038	68	48

Exhibit 6: Levelized Cost of Energy (LCOE) Assumptions

Item	Unit	Assumption
DC / AC Conversion	X	1.3
Size	MW	30
Capacity Factor	%	22%
Puerto Rico Solar Overnight Cost Adder	%	16%
Construction Finance Factor	%	1.02
Small Scale Adder	%	0%
Solar PV Capital Recovery Period	year	30
$2016 to $2018 Conversion	X	1.035

SIEMENS
Ingenuity for life

Exhibit 7: Levelized Cost of Energy (LCOE) of Solar PV – Base Case

Commercial on line year		2019	2020	2021	2022	2023	2024	2025
Construction Start Year		2018	2019	2020	2021	2022	2023	2024
Capital and Operating Costs								
Overnight Cost, US National, 100 MW	$2018/Wdc	1.05	0.98	0.93	0.92	0.91	0.90	0.89
AC/DC Conversion	X	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	$2018/Wac	1.58	1.48	1.41	1.39	1.38	1.36	1.34
IDC Cost Adder	%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
All-In Cost, Puerto Rico, 100 MW, $/Wac	$2018/Wac	1.60	1.51	1.43	1.41	1.40	1.38	1.36
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	$2018/Wac	1.60	1.51	1.43	1.41	1.40	1.38	1.36
Fixed O&M	$2018/kW-yr	11.85	10.88	10.13	10.02	9.92	9.81	9.70
30 MW Solar PV Project Parameters								
Capacity	MW	30	30	30	30	30	30	30
Capacity Factor	%	22%	22%	22%	22%	22%	22%	22%
Energy Produced	MWh	57,816	57,816	57,816	57,816	57,816	57,816	57,816
Base Capital PV System	$2018 thousand	48,028	45,203	42,848	42,365	41,881	41,397	40,913
Interconnection Costs	$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Land Costs	$2018 thousand	1,562	1,562	1,562	1,562	1,562	1,562	1,562
Total PV System Capital Costs	$2018 thousand	52,430	49,605	47,250	46,767	46,283	45,799	45,315
ITC	%	30%	30%	26%	22%	10%	10%	10%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	71%	71%	76%	81%	97%	97%	97%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized PV Capital Costs	$2018 thousand	3,510	3,321	3,392	3,584	4,219	4,175	4,131
Fixed O&M	$2018 thousand	355	326	304	301	297	294	291
Total Base PV System Cost	$2018 thousand	3,865	3,647	3,696	3,885	4,517	4,469	4,422
Levelized Cost of Energy (PV Base)	$2018/MWh	67	63	64	67	78	77	76

SIEMENS
Ingenuity for life

Exhibit 8: Levelized Cost of Energy (LCOE) of Solar PV – Low Case

Commercial on line year		2019	2020	2021	2022	2023	2024	2025
Construction Start Year		2018	2019	2020	2021	2022	2023	2024
Capital and Operating Costs								
Overnight Cost, US National, 100 MW	$2018/Wdc	0.91	0.87	0.83	0.81	0.79	0.76	0.74
AC/DC Conversion	X	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	$2018/Wac	1.38	1.31	1.26	1.22	1.19	1.15	1.11
IDC Cost Adder	%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
All-In Cost, Puerto Rico, 100 MW, $/Wac	$2018/Wac	1.40	1.33	1.28	1.24	1.20	1.17	1.13
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	$2018/Wac	1.40	1.33	1.28	1.24	1.20	1.17	1.13
Fixed O&M	$2018/kW-yr	10.45	9.69	9.10	8.85	8.61	8.36	8.12
30 MW Solar PV Project Parameters								
Capacity	MW	30	30	30	30	30	30	30
Capacity Factor	%	22%	22%	22%	22%	22%	22%	22%
Energy Produced	MWh	57,816	57,816	57,816	57,816	57,816	57,816	57,816
Base Capital PV System	$2018 thousand	41,881	39,929	38,269	37,186	36,102	35,018	33,934
Interconnection Costs	$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Land Costs	$2018 thousand	1,562	1,562	1,562	1,562	1,562	1,562	1,562
Total PV System Capital Costs	$2018 thousand	46,283	44,331	42,671	41,588	40,504	39,420	38,336
ITC	%	30%	30%	26%	22%	10%	10%	10%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	71%	71%	76%	81%	97%	97%	97%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized PV Capital Costs	$2018 thousand	3,099	2,968	3,063	3,187	3,693	3,594	3,495
Fixed O&M	$2018 thousand	314	291	273	266	258	251	243
Total Base PV System Cost	$2018 thousand	3,412	3,259	3,336	3,453	3,951	3,845	3,738
Levelized Cost of Energy (PV Base)	$2018/MWh	59	56	58	60	68	66	65

Minimum Technical Requirements (MTR)

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

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

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

Battery Storage

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

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

Installed Costs and Applications

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

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

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

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

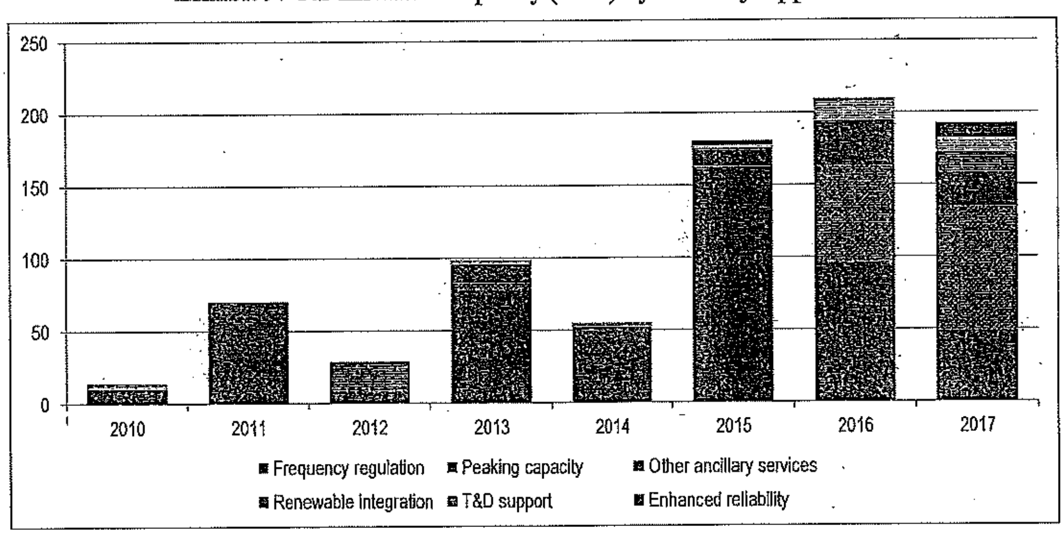
Other costs: These include financing costs (debt service payments), taxes paid, costs to meet local and regional regulatory requirements, and warranty costs.

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

- Peaker replacement: Large-scale energy storage system designed to replace peaking gas turbine facilities; brought online quickly to meet rapidly increasing demand for power at peak; can be quickly taken offline as power demand diminishes
- Distribution: Energy storage system designed to defer distribution upgrades, typically placed at substations or distribution feeder controlled by utilities to provide flexible peaking capacity while also mitigating stability problems
- Microgrid: Energy storage system designed to support small power systems that can "island" or otherwise disconnect from the broader power grid (e.g., military bases, universities, etc.) and to provide energy shifting, ramping support to enhance system stability and increase reliability of service (emphasis is on short-term power output vs. load shifting, etc.)

While the majority of installed capacity provides frequency regulation, recent projects have targeted alternative applications including peaking capacity, renewable integration, and peak shaving. Exhibit 9 shows the primary application for installed storage capacity in recent history. The primary application is defined as the service that motivated the project, generally the highest-value or most profitable service. The category "other ancillary services" includes voltage support, black start, and operating reserves; and the category "renewable integration" is primarily energy shifting.

Exhibit 9: U.S Installed Capacity (MW) by Primary Application



Source: Siemens, IHS Markit

Future Cost Trends

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

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

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

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

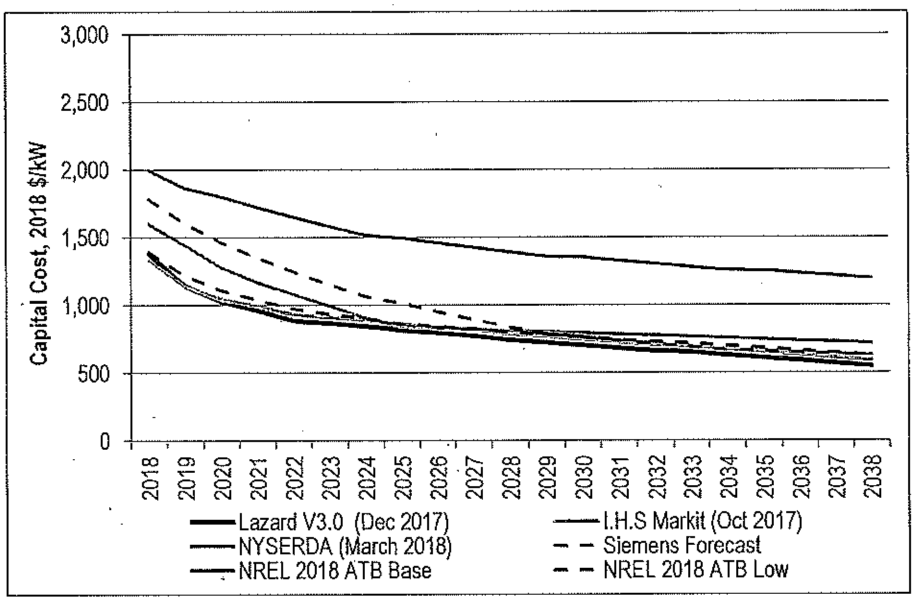
- Technological improvements, advances or breakthroughs, that lead to better performance, (e.g., cycle life, higher safety, more environmentally friendly, higher energy density, increasing voltage, higher power density);
- Using better, more stable materials to build battery parts, (e.g., electrodes, electrolytes, separators) that are able to deliver the better performance listed above;
- Using more effective chemistries, formulations, or crystal structures that overcome some of the limitations of today's technologies; and
- Using more stable solid electrolytes that enable higher voltages, reduce flammability, and make pure metal (e.g., lithium) anodes safer.

Li-ion Battery System Price Forecast

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

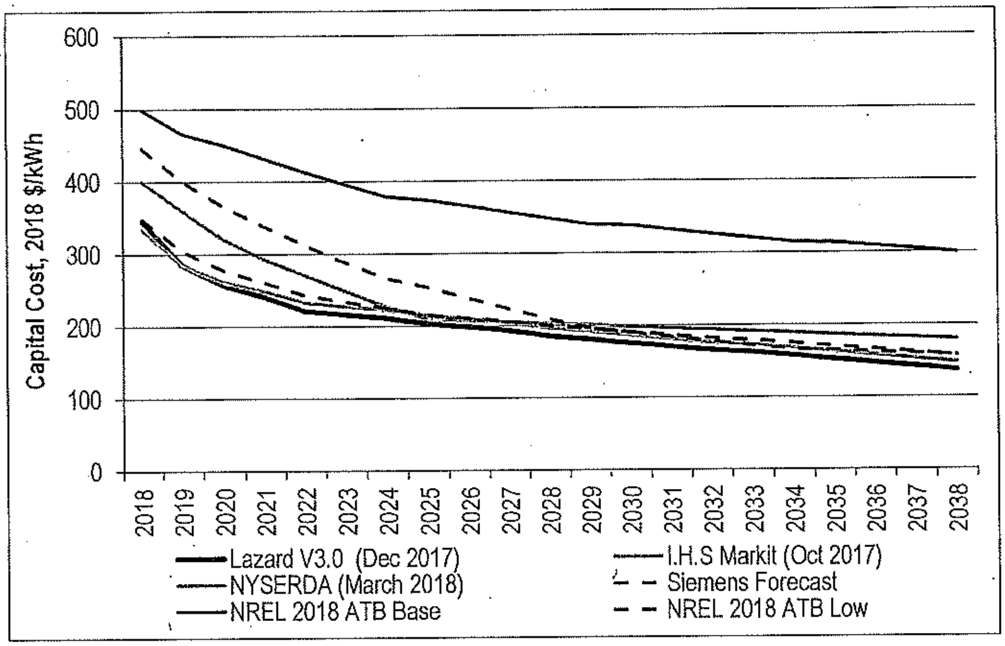
Exhibit 10 and Exhibit 11 represents our view of 4 hour 1 MW Li-Ion battery system price forecasts, in \$/kW and \$/kWh, respectively, in comparison with multiple other forecasts.

Exhibit 10: 4-hour Li-ion Battery System Capital Cost Forecasts



Source: Siemens, IHS, Lazard, NYSERDA, NREL

Exhibit 11: 4-hour Li-ion Battery System Capital Cost Forecasts



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

Source: Siemens, IHS, Lazard, NYSERDA, NREL

Exhibit 12 and Exhibit 13 present the capital and operating costs assumptions of 2 hour, 4 hour and 6 hour storage in the base case and low case separately.

Exhibit 12: Li-Ion Battery System Capital Cost and Operating Cost Assumptions – Base Case

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

Source: Siemens, NREL

SIEMENS
Ingenuity for life

Exhibit 13: Li-Ion Battery System Capital Cost and Operating Cost Assumptions – Low Case

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

Source: Siemens, NREL

SIEMENS
Ingenuity for life

MEMO TO: PREPA IRP Team

FROM: Siemens PTI/EBA

DATE: August 21, 2018

SUBJECT: PREPA IRP Load Forecast

The aim of this section is to present and discuss the gross electricity demand forecast (e.g. before any adjustments for future energy efficiency, demand response or distributed generation, which will be modeled separately and are provided in another memo), prepared as required for the development of the Integrated Resource Plan (IRP) for PREPA. This includes a concise presentation of the data used, a description of the methodology and the necessary assumptions, and finally the resulting load forecast. The forecast has been prepared for the IRP study horizon of fiscal year (FY) 2019-2038 (July 1, 2018 – June 30, 2038).

Data, Assumptions and Methodology

Historical Energy Sales

Siemens used monthly historical energy sales provided by PREPA for the econometric model used to develop the load forecast. Siemens used data for fiscal years (FY) 2000-2018 (July 1999 - June 2018) broken down into six customer classes; residential, commercial, industrial, agriculture, public lighting, and other. The commercial is the largest sector accounting for 47% of the total sales in FY 2017, followed by residential (38%) and industrial (13%). Overall, the combined sales to residential, commercial, and industrial customers represented 98% of the total in FY 2017, with the remaining 2% of sales coming mostly from the public lightning sector.

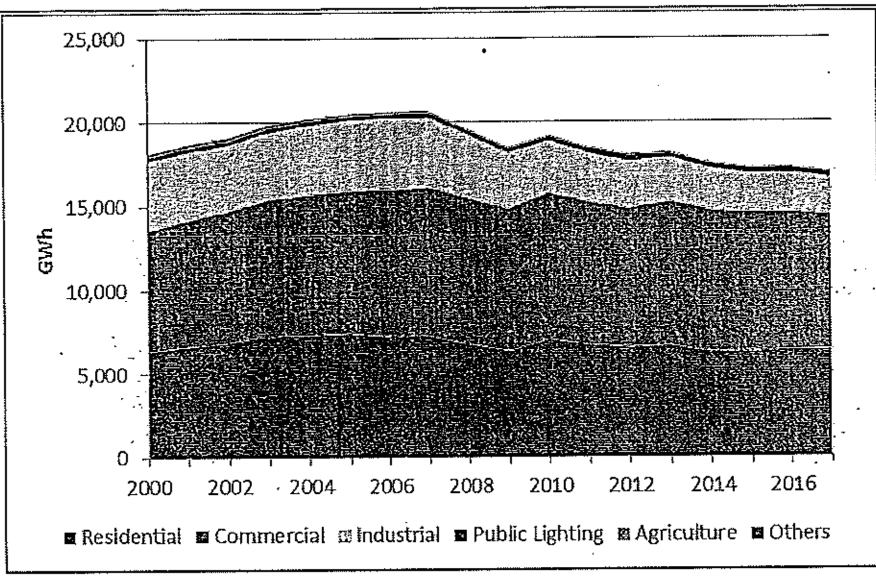
Electricity sales in Puerto Rico declined 18% since the Great Recession due to a structural decline in the economy and net migration of people out of the island with GNP and population falling by at least a percentage point annually since 2007[1]. For FY 2018, total sales declined 22%, reflecting the disruption in the transmission and distribution networks due to the hurricanes as well as customer billing delays[2].

Industrial salês declined 47% in FY 2007-2017, while residential and commercial fell 12% and 10%, respectively. Industrial share of the total demand declined from 20% in FY 2007 to 13% in FY 2017. In contrast, the share of commercial sales increased by 4 percentage points during the same period. Exhibit 1 shows historical energy sales for fiscal years 2000-2017 by customer class, as reported by PREPA.

[1] The prior six years 2000 to 2006 saw an average growth in the GNP of 1.4% yearly while the broader US economy saw a growth of 2.6%.
[2] Based on preliminary data provided by PREPA

SIEMENS
Ingenuity for Life

Exhibit 1: Historical PREPA Annual Sales by Customer Class (GWh)

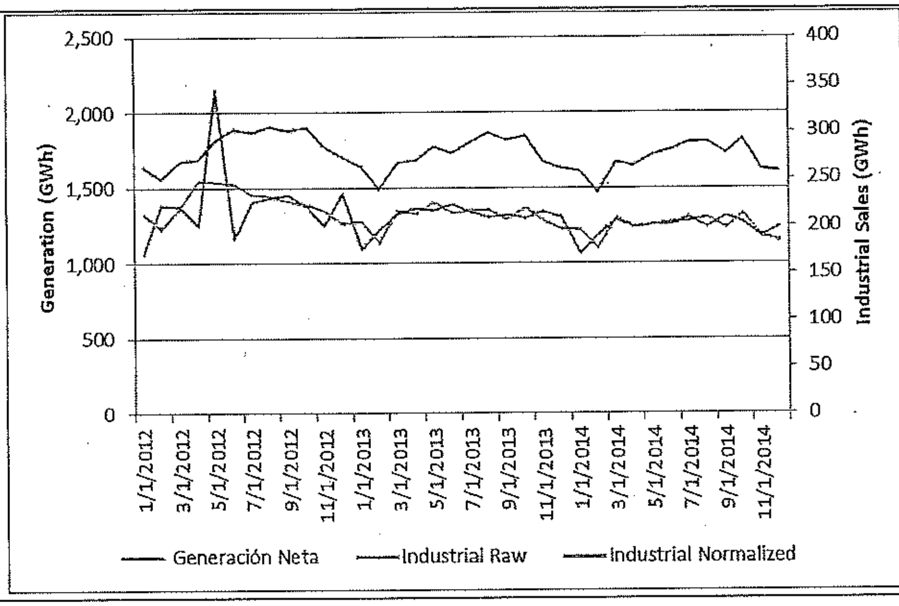


Source: PREPA

Energy sales were normalized for each of the six customer classes. PREPA indicated that historical sales can be affected by billing issues (delays, incorrect reporting, etc.), which might explain high volatility for some months, not in line with changes in monthly generation on a system wide basis. The volatility is particularly notorious after hurricanes Irma and Maria struck Puerto in the fall of 2017, with extreme volatility and low or even negative energy monthly sales numbers reported after September 2017. PREPA indicated, the Company is still in the process of validating data and making corrections for reported sales post Maria. For this reason, Siemens did not include historical numbers for fiscal year 2019 as part of the econometric regression analysis.

To correct for abnormal data volatility and avoid biases embedded in the forecast results, Siemens normalized the sales data by customer class using historic monthly generation and the relative share of each class to the total net generation reported. Exhibit 2 shows the normalization for the industrial customer class compared to the raw data and the net system generation for 2012-2014. The chart shows the normalization technique eliminated unexplained volatility in months such as May or June 2012, and the rise or fall in monthly sales not following net generation levels. The normalized data was used for the econometric regression analysis described next.

Exhibit 2: Historical Normalized data for the Industrial Customer Class



Load Forecast Methodology

The applied methodology considered mathematical models using statistical and econometric tools to develop forecast series of monthly energy sales for the three largest customer classes, residential, commercial and industrial. The gross energy demand forecast is developed using a Classical Linear Regression Model (CLRM) in which the dependent variable, energy sales, is expressed as a linear combination of the independent variables. For Puerto Rico, 15 variables were used including a weather variable (cooling degree days), two economic variables (population and GNP), and 12 month specific dummy variables (one for each month of the year) to capture the seasonality of energy demand on a monthly basis. For industrial demand, manufacturing employment was also included as an explanatory variable instead of the population in the regression analysis. Population was found not to have statistical significance with industrial growth expected to drive future population growth, not vice versa.

The econometric model uses the ordinary least-squares regression technique in MATLAB. This approach is widely used to develop long-term load forecasts by independent system operators like PJM in the U.S. or the California Energy Commission in their annual load forecast studies. Siemens used monthly historical data for FY 2000 through FY 2017 to estimate the regression coefficients applied to the forecast, with 210 observations for each variable.

The coefficients that are produced, unique to each independent variable, are used to develop the gross energy forecast along with projections of the independent variables (weather, GNP, population and manufacturing employment). The 12 month dummy binary variables were included in the forecast formulation to capture monthly seasonality in demand. The sum product of the coefficients and variables on a monthly basis result in the gross energy forecast shown below:

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

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

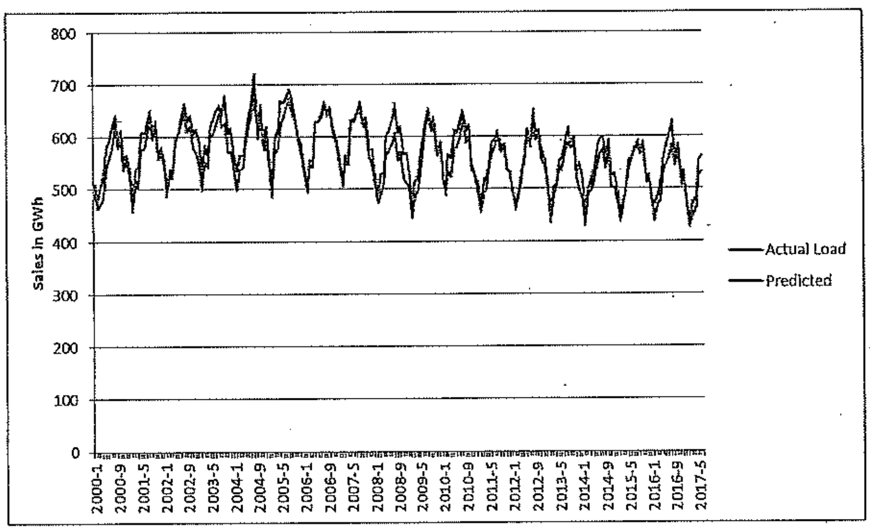
Exhibit 3 illustrates the variables used to develop the forecast for each of three largest classes.

Exhibit 3: Independent variables for Each Customer Classes

Residential	Commercial	Industrial
• CDD • GNP • Population • 12 month variables	• CDD • Population • 12 month variables	• CDD • GNP • Manufacturing Employment • 12 month variables

The statistical significance of the explanatory variables and predicted fit of the model for each class was robust, as shown in Exhibit 4 for the residential class. The predicted values followed monthly historical sales to a great extent. The regression coefficients, adjusted R^2s, and F-stats from the econometric model for each class are shown in Appendix A.

Exhibit 4: Residential Class Predicted Fit vs. Actuals



Source: PREPA, Siemens

For the smaller customer classes (agriculture, lighting and other) the overall fit of the CLRM model was not as robust with the economic and weather fundamental variables providing a much lower explanatory value on the energy demand for each class. For these customer classes, Siemens developed the forecast based on their historical seasonality and using a simpler extrapolation technique with the expectation that each class follow similar growth rates to the overall system.

Fundamental Drivers for the Load Forecast

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

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

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

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

Exhibit 5 below shows the historical annual values for the independent variables used in the regression analysis.

Exhibit 5: Historical Population, Macroeconomic, and Weather Variables

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

Source: FOMB (GNP), Moody's (Population), NOAA (weather), FRED (Manufacturing Employment)

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

Population declined 15% since 2007 with Maria and Irma accounting for 4 percentage points of this decline in population (182 thousand people in 2017) due to the combined impact of migration and the death toll after the storm, estimated at over 4,100 people[3].

Macroeconomic and Weather Projections

Historical monthly NOAA data was retrieved (2000-2016) to develop expected monthly Cooling Degree Days (CDD) under normal weather conditions for the forecast. Exhibit 6 shows the normalized CDD used for the forecast.

Exhibit 6: Weather Variables

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

Source: NOAA, Siemens

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

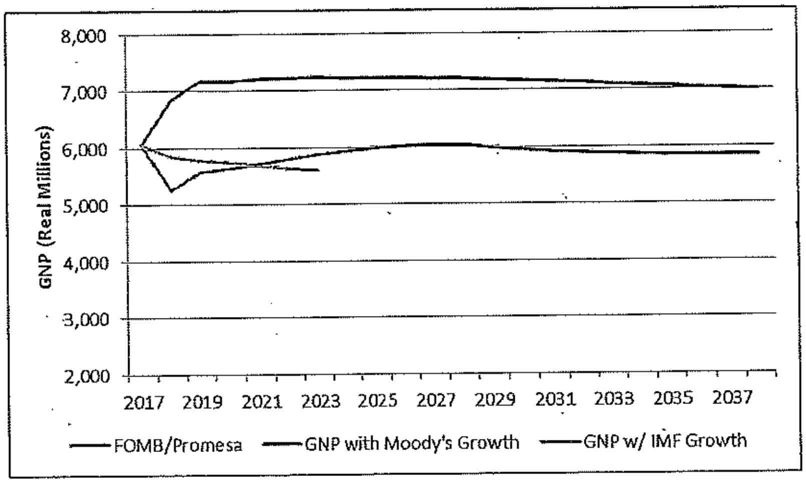
Siemens considered other outlooks as well, including Moody's and the IMF, as shown on Exhibit 7. Moody's projects the GDP to recoup much of its hurricane-related losses and to remain relatively stable throughout the forecast horizon. The IMF shows a more pessimistic forecast through 2023 with GDP not recovering from the aftermath of hurricane Maria in 2017.

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

SIEMENS

Ingenuity for life

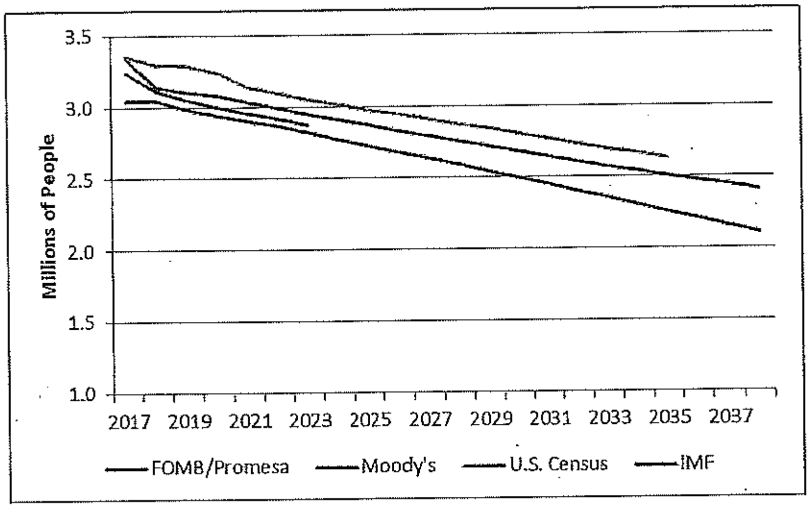
Exhibit 7: Puerto Rico GNP Forecasts



Note: The forecast have been standardized for comparison purposes using the implied growth rates. Moody's GNP forecast is based on real 2009$ and the IMF based on real 1954$.
Sources: Moody's June 2018 Forecast, IMF April 2018 WEO, Financial Oversight and Managing Board of Puerto Rico, Fiscal Plan April 2018

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

Exhibit 8: Puerto Rico Population Forecast



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

Exhibit 9 shows the long-term economic forecast used in the load forecast.

Exhibit 9: Macroeconomic Long Term Forecast

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

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

Long Term Energy Forecast

Exhibit 10 shows gross energy sales by customer class forecasted by Siemens. The forecast does not include any future energy efficiency and/or demand response programs and distributed generation (DG) in addition to current programs in place. The impact of those programs will be addressed and modeled separately. The forecast does include the impact of naturally occurring energy efficiency savings such as more efficient household appliances in as much it is included in the historical data used to create the model.

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

Agriculture, public lightning and "other" are projected to decline in line with the overall system at -0.23% per year. The public lighting forecast shown below does not include the impact of a large replacement of current oil-based public lightning with LED light bulbs. That will be addressed in a separate memo along with all other future energy efficiency programs.

Exhibit 10: Gross Sales Demand by Customer Class

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

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

Exhibit 11 illustrates the gross demand for generation inclusive of the generation auxiliary loads, technical and non-technical loses, and PREPA's own use. The first column, gross energy sales reflects the totals from Exhibit 10. PREPA's own use is assumed to stay constant through the forecast. No auxiliary generation is assumed to be retired. However, for the portfolio scenario analysis of the Integrated Resource Plan, future retirements will be incorporated into the forecast and their corresponding impact on demand.

Exhibit 11: Gross Energy Demand for Generation

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

To assess the geographical location of the demand above as necessary for the modeling of the system, PREPA provided the composition of the load in term of customer classes (residential, commercial, industrial, etc.) by County which was used to map the forecast to each of the areas into which the system is modeled. Exhibit 12 and Exhibit 13show the resulting allocation of the Energy Demand for Generation above in tabular and graphic form.

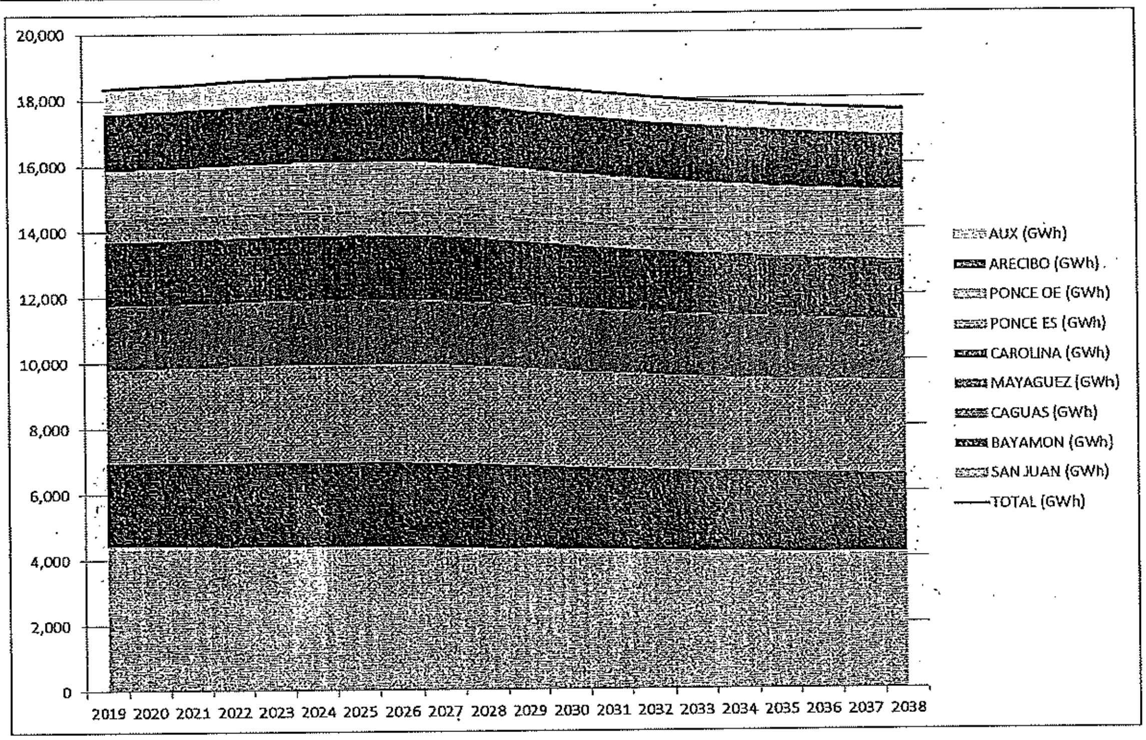
Exhibit 12: Gross Energy Demand for Generation by Area

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

SIEMENS

Ingenuity for life

Exhibit 13: Graph of Gross Energy Demand for Generation by Area



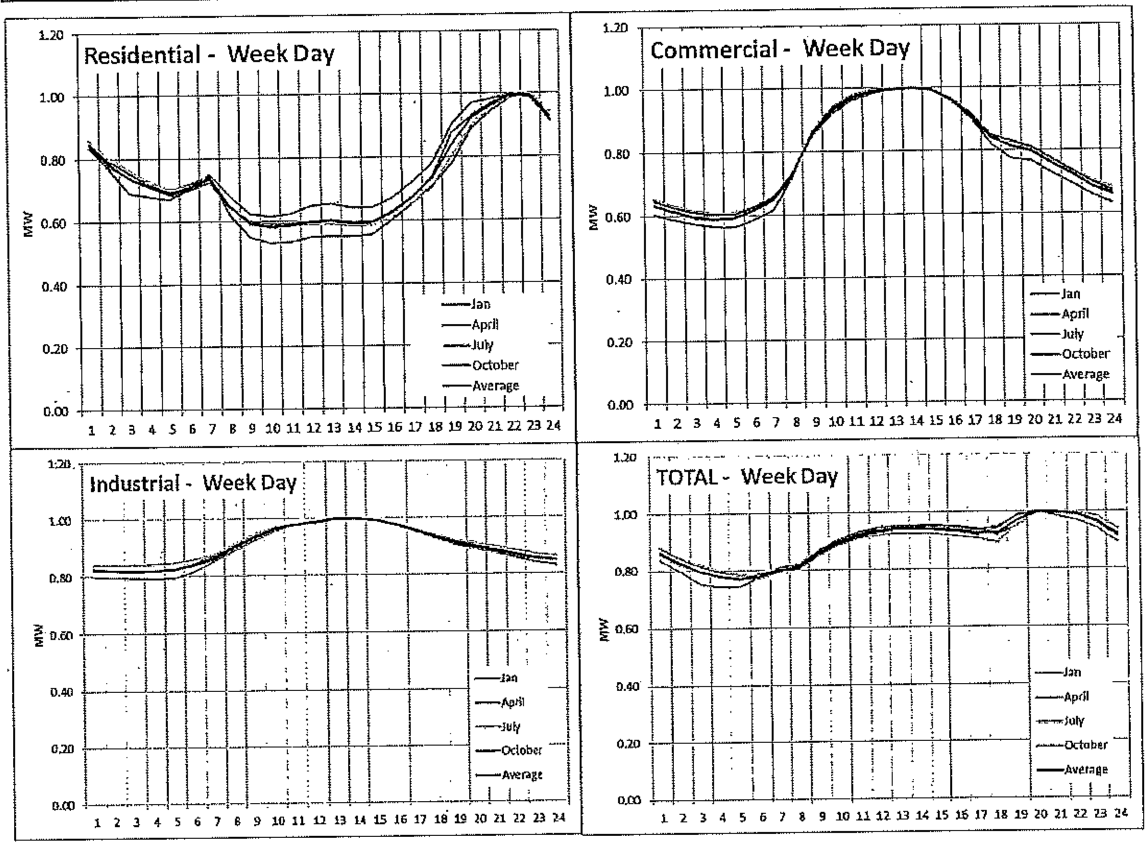
Source: Siemens

Long Term Peak demand Forecast

To estimate the peak demand associated with the energy forecast it is necessary to determine for each customer class their expected load factors (i.e. the ratio of average demand to the peak demand) and the percentage of their peak demand that occurs at the time of the system peak (called Customer Class Coincidence Factor – CCCF - or Contribution to the Peak Factor). These factors in principle should be determined monthly in line with the monthly granularity of the energy forecast. However single values equal to the average of the determined monthly values was preferred due to the fact that: a) there is not a significant change in the hourly load shapes for the relevant customer classes across the year, b) the load factor can be volatile unless averages are made due to its dependence on the measured peak and c) only one year worth of hourly load data by customer class was available.

Exhibit 14 shows the normalized load shapes for the main customer classes (Residential, Commercial and Industrial) that make up most of the energy consumption as well as the system total. As can be observed, unlike the mainland US where there are large changes in the shape from summer to winter, in Puerto Rico the shapes are largely the same (residential shows the greater variation) and an average load factor can be used to represent each customer class. We also note in the Exhibit below that there are two peaks a day time peak driven by commercial and industrial loads and a night peak driven by the residential load and this is the higher of the two. Thus the residential customers peak at the same time as the system (CCCF =1) while the industrial and commercial customers have a lower peak at this time (CCCF < 1).

Exhibit 14: Normalized Load Shapes for main Customer Classes and System Total



Source: Siemens

Based on the hourly information provided Siemens estimated the load factors and Customer Class Coincidence Factors (% of the Customer Class peak at the time of the System Peak) shown in Exhibit 15.

Exhibit 15: Selected Load Factors and Customer Class Coincidence Factor

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

Source: Siemens

Using the values above and the forecasted energy consumption by customer class, the peaks demand and the demand at the time of system peak can be determined. To this peak the following is added: a) effect of the technical transmission and distribution technical loses using a correction to convert energy losses into capacity losses based on the load factor[4], b) non-technical loses using same values as the residential load, c) PREPA own consumption using an estimated load factor based on historical values and b) finally the effect of the consumption of the generating plants auxiliary services.

[4] Capacity Losses % = (Energy Losses %) / (0.3+0.7*LF)

Exhibit 16 shows the gross average and peak demand for generation, inclusive of the factors indicated above (technical and non-technical losses, auxiliary demand and PREPA's own use). Exhibit 16 does not include the impact of future energy efficiency and/or demand response programs or DG, which are modeled and addressed separately.

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

Exhibit 16: Gross Average and Peak Demand for Generation

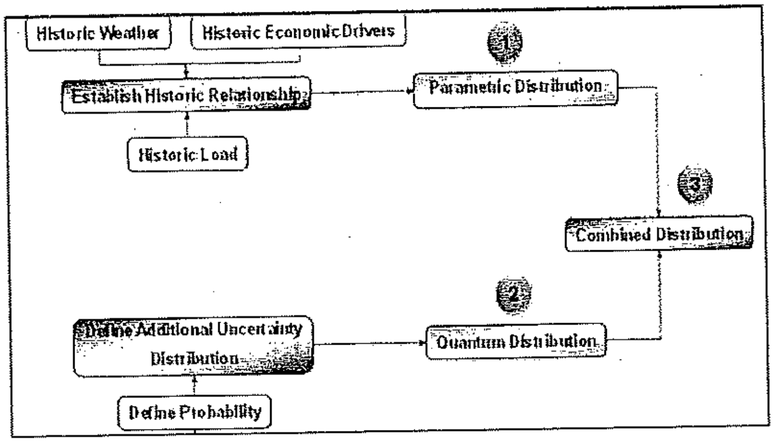
Fiscal Year	Average Demand (MW)	Peak Demand (MW)	Load Factor (%)
2019	2,095	2,791	75.1%
2020	2,102	2,799	75.1%
2021	2,108	2,805	75.2%
2022	2,117	2,815	75.2%
2023	2,125	2,823	75.3%
2024	2,131	2,829	75.3%
2025	2,133	2,831	75.3%
2026	2,134	2,830	75.4%
2027	2,128	2,822	75.4%
2028	2,119	2,810	75.4%
2029	2,100	2,785	75.4%
2030	2,085	2,765	75.4%
2031	2,071	2,748	75.4%
2032	2,059	2,731	75.4%
2033	2,047	2,716	75.4%
2034	2,037	2,703	75.4%
2035	2,029	2,692	75.4%
2036	2,021	2,682	75.4%
2037	2,015	2,673	75.4%
2038	2,010	2,666	75.4%
CAGR	-0.22%	-0.24%	

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

Stochastic Distribution

To generate scenarios for load growth, Siemens developed statistical distributions based on the deterministic load forecasts. The process involves two steps, the first one, encompasses developing parametric distributions around the key fundamental variables that could present more volatility in the future (weather and economic performance in Puerto Rico) utilizing historical data to develop 2,000 scenarios for weather and GDP that are feed into the econometric regression model to determine 2,000 iterations of average and peak load. The second step involves developing Quantum distributions, which incorporate future uncertainties not captured by the historical data. The overall process is summarized by the flow chart in Exhibit 17 below.

Exhibit 17: Stochastic Process



Parametric Distributions

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

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

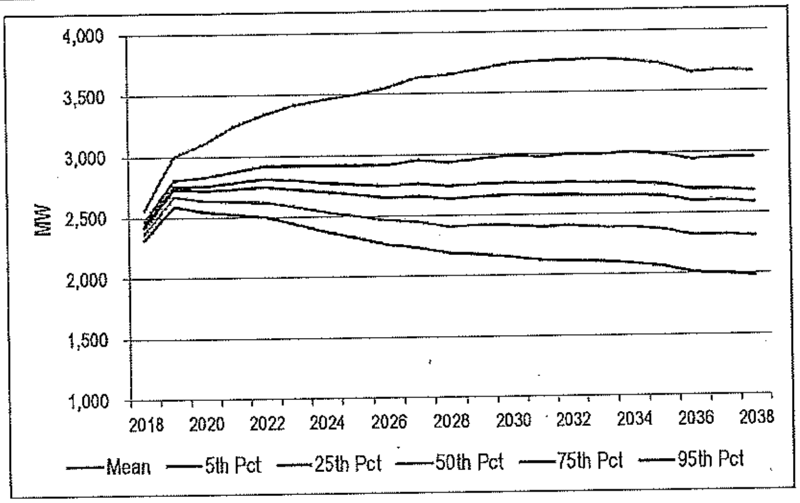
Based on historical volatility, 2,000 distributions of these variables are developed and used in the stepwise regression model to develop an intermediate distribution of average and peak load distributions for the forecast time period.

Quantum Distribution: Additional Variability

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

Exhibit 18 shows an illustrative stochastic distribution for the peak demand for generation for planning purposes.

Exhibit 18: Illustrative Peak Demand for Generation Stochastic Distribution (to be updated upon consensus on base forecast)



Note: Forecast reflects peak demand inclusive of loses, auxiliary demand and PREPA's own use (system wide peak). Forecast does not include energy efficiency and/or demand response programs additional to existing programs.

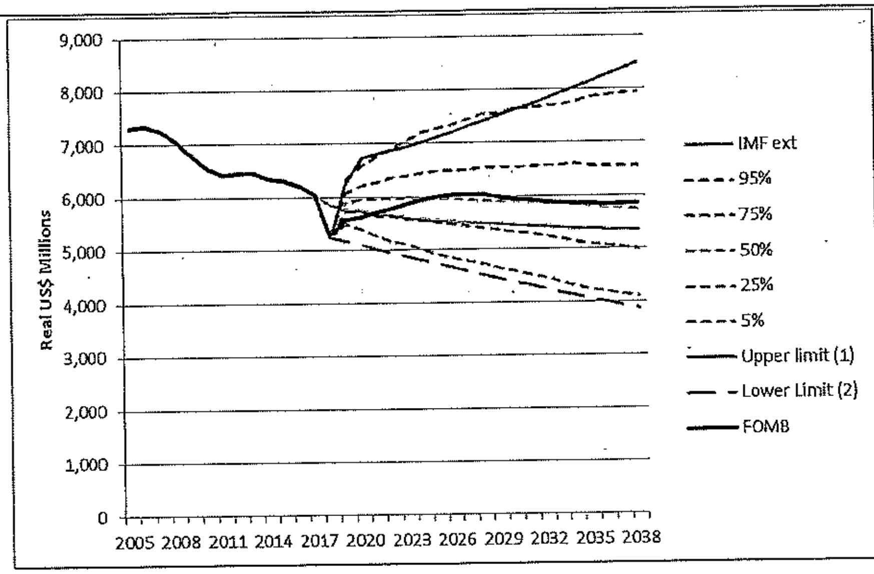
The mean load path corresponds to the average of 2,000 iterations of combinations of the stochastic input drivers. The percentile bands are not load paths but instead represent the likelihood that the peak demand could be at or below that level in a given year. For example, in 2025 there is a 95% likelihood that peak demand will be at or below 3,497 MW. Also in 2025, there is a 5% chance that peak demand will be at or below 2,323 MW.

In addition to the above and to provide some rationale on the factors that could give rise to the high and low forecasts mathematically obtained above, Siemens developed and "Upper Limit" or optimistic scenario and a "Lower Limit" or pessimistic scenario for the macroeconomic parameters driving the forecast: GNP and population.

The Upper Limit assumes that the structural reforms in Puerto Rico are highly successful and the GNP after hitting a low in 2018 bounces back at a rate 50% faster than Moody's forecast for two years as federal funds are invested in the island. From 2020 onwards the Puerto Rico economy recovers to its pre-2006 potential and the GNP grows at 75% of the US GDP forecast growth rate – see Exhibit 19. Consistent with this economic outlook there is initially a drop in population following the US Census forecast until 2019 and from 2020 onwards, as the Puerto Rico economy starts to grow, the population outflow reduces to only 25% of the yearly attrition in the US Census forecast – see Exhibit 20.

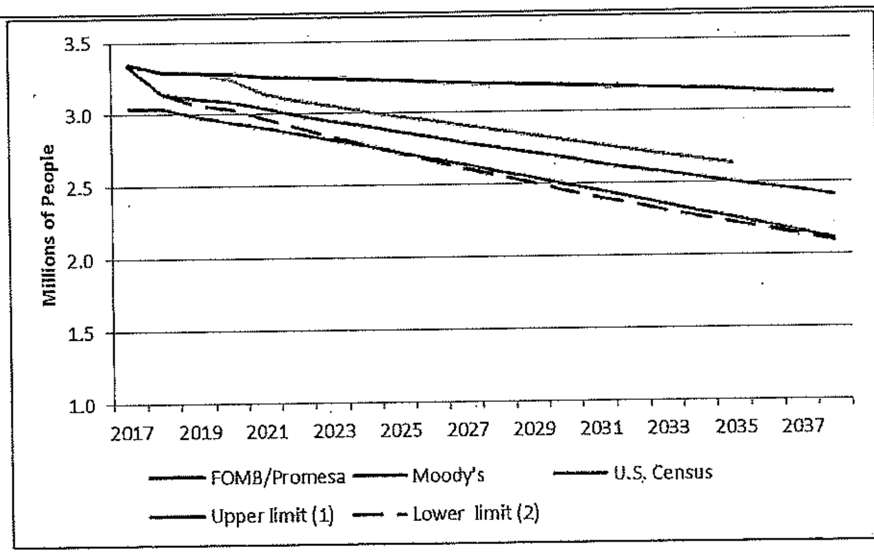
The Lower Limit on the other hand, assumes that the structural reforms do not take place and there is limited federal funds invested in the island, resulting in a continuation of the GNP decline at 1% per year in line with the historical post 2006 decline. Consistent with this outlook the population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

Exhibit 19: GNP Scenarios



Source: Siemens

Exhibit 20: Population Scenarios



Source: Siemens

The resulting gross sales forecasts for the Upper and Lower limits are shown in Exhibit 21. In the high case scenario, gross energy sales increase at 1.34% per-year, with sales reaching 20,672 GWh by 2038 – 41% higher than the reference case. In the low case scenario, gross energy sales decline at 1.50% per-year reaching 11,033 GWh by 2038, 75% below the reference case level. The industrial customer class has the most upside or downside potential driven by changes in the GNP and or population from all three classes, with sales growing at 5.6% per-year in the high case, or declining at 5.2% per-year in the low case.

Exhibit 21: Gross Sales Forecast Scenarios – Resulting Upper and Lower Limits

Fiscal Year	Gross Energy Sales Reference (GWh)	Gross Energy Sales UPPER Limit (GWh)	Gross Energy Sales LOWER Limit (GWh)
2019	15,301	16,043	14,703
2020	15,357	17,400	14,470
2021	15,403	17,869	14,257
2022	15,470	17,976	14,015
2023	15,530	18,102	13,776
2024	15,574	18,239	13,545
2025	15,595	18,385	13,325
2026	15,596	18,540	13,112
2027	15,554	18,699	12,901
2028	15,487	18,863	12,695
2029	15,341	19,030	12,498
2030	15,223	19,200	12,304
2031	15,120	19,372	12,118
2032	15,025	19,547	11,939
2033	14,939	19,725	11,765
2034	14,862	19,906	11,597
2035	14,796	20,091	11,439
2036	14,741	20,280	11,295
2037	14,694	20,474	11,160
2038	14,654	20,672	11,033
CAGR	-0.23%	1.34%	-1.50%

Source: Siemens

SIEMENS
Ingenuity for life

Appendix A

Econometric Model Regression Coefficients by Customer Class

Residential		
Variable	Coefficient	Statistical Significance
Constant	-227.36	
CDD	0.366	Yes
GNP	0.047	Yes
Population	91.083	Yes
Jan	-50.592	Yes
Feb	-84.916	Yes
Mar	-64.889	Yes
Apr	-67.875	Yes
May	-36.025	Yes
Jun	-32.552	Yes
Jul	-22.369	Yes
Aug	0.000	Yes
Sep	-31.389	Yes
Oct	-15.618	Yes
Nov	-42.071	Yes
Dec	-26.040	Yes
Adjusted R^2	0.822	
F-Stat	824.8	

Commercial		
Variable	Coefficient	Statistical Significance
Constant	278.1	
CDD	0.456	Yes
Population	57.583	Yes
Jan	-23.315	Yes
Feb	-43.672	Yes
Mar	-2.185	Yes
Apr	-22.364	Yes
May	-13.705	Yes
Jun	-25.823	Yes
Jul	-26.560	Yes
Aug	0.000	Yes
Sep	-26.452	Yes
Oct	15.459	Yes
Nov	-10.917	Yes
Dec	1.679	Yes
Adjusted R^2	0.587	
F Stat	23.9	

Industrial		
Variable	Coefficient	Statistical Significance
Constant	-532.88	
CDD	0.11	Yes
GNP	0.09	Yes
Jan	-13.98	Yes
Feb	-25.86	Yes
Mar	-4.49	No
Apr	1.21	No
May	11.30	Yes
Jun	-0.31	No
Jul	1.32	No
Aug	2.89	No
Sep	-11.79	Yes
Oct	-3.09	No
Nov	-9.52	Yes
Dec	0.42	No
Manufacturing Employment	1.62	Yes
Adjusted R^2	0.969	
F Stat	434.71	

SIEMENS
Ingenuity for life

MEMO TO: PREPA IRP Team

FROM: Siemens IRP Team

DATE: August 30, 2018

SUBJECT: Energy Efficiency and Demand Response Projections for PREPA IRP

As inputs to PREPA's IRP, energy efficiency (EE) and demand response (DR) measures can serve as cost-effective and clean demand-side resources. To date, PREPA's demand-side program offerings have largely been energy efficiency conservation campaigns. The Puerto Rico Energy Public Policy Office (EPPO) has also offered efficiency programs focused on low income customers but the tracking and reporting of associated savings was limited. The Puerto Rico Energy Commission Regulation 9021, Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority, specifically requires that the IRP considers demand side resources, including EE and DR, as a means to satisfy electric demand over the study period.

To reasonably project EE and DR for the IRP, first a list of potential measures was developed based on effective programs implemented in similar climates and island settings that would yield measurable savings. PREPA reviewed this list and filtered down the measures to a subset which were deemed most appropriate for PREPA. These measures were then evaluated and characterized using models which build estimates based on participation rates, energy savings, and program costs. This memorandum details the estimated availability of energy savings and associated costs from new demand side measures.

ENERGY EFFICIENCY

The initial list of potential energy efficiency measures included a variety of potential measures to consider including residential and commercial lighting, residential and commercial air conditioning, efficient refrigerator rebates, low income weatherization measures, residential ceiling insulation, residential solar water heaters, and advanced residential new construction building codes. This broad list was presented to PREPA and discussed further to consider the feasibility and potential magnitude of energy savings as it relates to the IRP. The EPPO manages two EE programs; the Weatherization Assistance Program (WAP) and a local program, Low Income Home Assistance Program – LIHEAP (similar to the WAP), through the Department of Family Affairs. EPPO provided PREPA some insight regarding both programs. The refined list of energy efficiency projects determined to be the most realistically implemented and would result in the greatest volume of energy savings is presented in Exhibit 1. Detailed projections for these measures were then developed for inclusion in the IRP.

SIEMENS

Ingenuity for life

Exhibit 1: Summary Energy Efficiency Measures

EE Program	Program Description	Rationale	Key Assumptions	Est. Cost Effectiveness Range (TRC)
Residential A/C	Incentivizes higher efficiency A/C units in existing homes	Residential consumption represented ~36% of PREPA's total energy load in 2017, and space cooling is a major component of this consumption. This measure provides rebates for the installation of higher efficiency 12 EER A/C units.	Participation rates, energy savings, and program costs are based on comparable programs with adjustments made for Puerto Rico to account for the prevalence of window and split A/C units in homes.	3 - 5
Residential Lighting	Provides free LEDs to residential customers	This measure provides LED bulbs to residential customers with 5 per customer and 60W equivalent bulbs. This measure offers an option for the nearly 1/3 of customers who rent their residence. Similar lighting projects have also been used in Barbados and Jamaica (Pilot).	Participation rates increase up to 2.5% annually where participants are using incandescent lamps as a baseline	4 - 6
Commercial A/C	Incentivizes higher efficiency A/C systems in existing commercial buildings	This measure provides an incentive for the installation of more efficient (17 SEER) 5-ton A/C systems in commercial buildings. A prescriptive 5-ton unit size was used to model this measure to simplify the initial program design. Comparable programs are offered by mainland U.S. utilities in Florida and in many other states.	This program model had to assume typical commercial building A/C sizes. Industry calculators were used to estimate the resulting savings from the higher efficiency A/C unit.	1 - 2
Commercial Lighting	Incentivizes installation of high efficiency lighting in commercial buildings	This measure provides commercial customers with a rebate for efficient lighting retrofits which is based on a $ / kW reduction in lighting demand resulting from the retrofit and considers different lighting technologies. Comparable programs are offered by mainland U.S. utilities in Florida and in many other states.	A significant assumption is the annual kWh savings per participant, which was based on a review of comparable lighting programs. This estimate could be better informed by more granular data on commercial building loads in Puerto Rico should this data become available.	3 - 4
Public Street Lighting	Funded full conversion of public street lighting to LED lamps	Street lighting historically accounted for around 2 percent of PREPA's total load. New and more efficient technologies exist and are cost competitive. A full conversion of Puerto Rico's public street lighting, from conventional incandescent lamps to LED, phased in over 5 years.	A key assumption to this measure is that public funding for this project is available.	na
Residential Rebuilding Efficiency	Rebuilding Hurricane destroyed and damaged homes with higher efficiency cooling, appliances and lighting	Additional efficiency is assumed as the remaining homes are rebuilt and restored.	Efficiency savings based on aligned with FOMB Financial Plan	n/a

Source: Newport Partners, LLC, PREPA

The ranges for Total Resource Costs[1] (TRCs) are based on key assumed inputs for PREPA and a review of comparable programs in the U.S. including utilities in Florida, Hawaii, Massachusetts, and Illinois. Most existing programs are well established, have large numbers of participants, and are part of a larger portfolio of energy efficiency and demand response programs. In initial piloting of these measures, PREPA metrics may be more variable and actual TRC values may be lower relative to the estimated range.

Residential Air Conditioning

This program offers residential customers an incentive to install a higher efficiency air-conditioning equipment in their home, which will reduce cooling energy consumption. Window units are assumed to be eligible.

Key assumptions underlying the projected costs and energy savings for residential air conditioning incentives as an energy efficiency measure include:

- Participation ranges from 1 to 4 percent of eligible residential customers in for the initial years of the program offering;
- Participants receive a $50 incentive towards the purchase of more efficient window units;
- Additional administrative costs are assumed to implement the program;
- Average annual energy savings are assumed to be 500 kWh for window units based on Energy Star program data;
- The window air conditioning unit program assumes a 10 year unit life and the program running from 2019 to 2023 and then sun setting through 2028 after which the program resumes as the original units reach their end of life.

The TRC of this program was calculated to be 4.4 and with a program plus incentives cost of 6.0 cents/kWh[2], this last value calculated by dividing the Present Value of the program + incentives costs at a WACC of 8.5% over the present value of the program energy savings using the same discount rate. Without discounting the cost is 4.5 cents per kWh. A summary of the residential air conditioning program energy savings and program costs is presented in Exhibit 2.

[1] The TRC is calculated as the present value of the avoided energy cost (energy savings x average rate) to the present value of the program costs. The present value was determined using a discount rate of 8.5% and for the average rate we are currently using 25 cents/kWh. However, this rate is expected to reduce and will reassessed once the IRP is complete.
[2] To account for continued life of assets beyond the end the program we continued the savings for 10 years after the last programmed expenditure.

Exhibit 2: Residential Air Conditioning Projections

	Participant Costs	Utility Program Costs (nominal$)	Utility Incentive Costs (nominal$)	Total Costs (excluding incentives) (nominal$)	Annual MWh Savings - TOTAL
2019	$602,407	$3,012,035	$1,004,012	$3,614,441	10,040
2020	$928,134	$4,640,672	$1,516,559	$5,568,806	25,206
2021	$1,271,099	$6,355,493	$2,036,234	$7,626,591	45,568
2022	$326,399	$1,631,995	$512,622	$1,958,394	50,694
2023	$335,258	$1,676,288	$516,210	$2,011,545	55,856
2024	$0	$0	$0	$0	55,856
2025	$0	$0	$0	$0	55,856
2026	$0	$0	$0	$0	55,856
2027	$0	$0	$0	$0	55,856
2028	$0	$0	$0	$0	55,856
2029	$1,181,075	$5,905,377	$1,614,822	$7,086,452	61,964
2030	$1,213,130	$6,065,649	$1,626,126	$7,278,779	63,060
2031	$1,246,054	$6,230,271	$1,637,509	$7,476,325	59,073
2032	$1,279,872	$6,399,360	$1,648,971	$7,679,232	70,436
2033	$1,314,608	$6,573,039	$1,660,514	$7,887,647	81,879
2034	$0	$0	$0	$0	81,879
2035	$0	$0	$0	$0	81,879
2036	$0	$0	$0	$0	81,879
2037	$0	$0	$0	$0	81,879
2038	$0	$0	$0	$0	81,879
Total	$9,698,035	$48,490,177	$13,773,578	$58,188,212	1,212,457

Source: Newport Partners, LLC

Residential Lighting

This program offers residential customers a voucher for five free LED bulbs (60 W equivalent). This is assumed to be a standalone program here, but could be combined with a home energy audit program which could qualify customers for other energy efficiency programs. This measure would also be applicable to the nearly one third of PREPA's residential customers who are renters. The measure also helps reduce evening peak loads.

Key assumptions underlying the projected costs and energy savings for residential lighting incentives as an energy efficiency measure include:

- Participation increases to 2.5 percent of eligible customers participating in the program in the early years of the offering;
- There is no additional cost to participants;
- Additional administrative costs are assumed to implement the program; and
- Annual household energy savings assumed to be 172 kWh based on the assumed five replacement bulbs operating for 2 hours per day and replacing incandescent bulbs.

SIEMENS
Ingenuity for life

The TRC of this program was calculated to be 5.9 and with a program plus incentives cost of 4.2 cents/kWh[3], this last value calculated by dividing the Present Value of the program + incentives costs at a WACC of 8.5% over the present value of the energy savings using the same discount rate. Without discounting the cost is 2.3 cents per kWh. A summary of the residential lighting program energy savings and program costs is presented in Exhibit 3.

Exhibit 3: Residential Lighting Projections

	Participant Costs	Utility Program Costs (nominal$)	Utility Incentive Costs (nominal$)	Total Costs (excluding incentives) (nominal$)	Annual MWh Savings - TOTAL
2019	$0	$870,143	$0	$870,143	2,297
2020	$0	$1,787,518	$0	$1,787,518	6,922
2021	$0	$2,295,039	$0	$2,295,039	12,744
2022	$0	$2,357,326	$0	$2,357,326	18,606
2023	$0	$2,421,304	$0	$2,421,304	24,510
2024	$0	$2,487,018	$0	$2,487,018	30,455
2025	$0	$2,554,516	$0	$2,554,516	36,442
2026	$0	$2,623,845	$0	$2,623,845	42,470
2027	$0	$2,695,056	$0	$2,695,056	48,541
2028	$0	$2,768,200	$0	$2,768,200	54,654
2029	$0	$2,843,329	$0	$2,843,329	60,810
2030	$0	$2,920,497	$0	$2,920,497	67,010
2031	$0	$2,999,759	$0	$2,999,759	73,252
2032	$0	$3,081,173	$0	$3,081,173	79,538
2033	$0	$3,164,796	$0	$3,164,796	85,869
2034	$0	$3,250,688	$0	$3,250,688	92,243
2035	$0	$3,338,912	$0	$3,338,912	98,662
2036	$0	$3,429,530	$0	$3,429,530	105,126
2037	$0	$3,522,608	$0	$3,522,608	111,636
2038	$0	$3,618,211	$0	$3,618,211	118,191
Total	**$0**	**$55,029,468**	**$0**	**$55,029,468**	**1,169,978**

Source: Newport Partners, LLC

Commercial Air Conditioning

This program offers commercial customers an incentive to install a more efficient air-conditioning system in their commercial buildings, which will reduce cooling energy consumption. A prescriptive 5-ton, 17 SEER unit size was used to model this measure to simplify the initial program design. Comparable programs are offered by mainland U.S. utilities in Florida and in many other states.

Key assumptions underlying the projected costs and energy savings for commercial air conditioning incentives as an energy efficiency measure include:

- On average between one half and one percent of eligible commercial customers participate;

[3] To account for continued life of assets beyond the end the program we continued the savings for 10 years after the last programmed expenditure.

SIEMENS
Ingenuity for life

- All participants use central air conditioning and receive a $700 incentive towards a more efficient unit;
- Additional administrative costs are assumed to implement the program;
- Average annual energy savings are assumed to be 1,750 kWh for commercial systems based on a range of SEER calculators and reported savings from Florida utility reported program savings programs; and
- The commercial air conditioning unit program assumes a 15 year unit life.
- The commercial air conditioning unit program assumes that program sunsets after 8 years due to maximized participation and optimized costs/savings. The program resumes in Year 16 to reflect 15-year unit life and need for replacement.

The TRC of this program was calculated to be 2.0 and with a program plus incentives cost of 8.0 cents/kWh[4], this last value calculated by dividing the Present Value of the program + incentives costs at a WACC of 8.5% over the present value of the energy savings using the same discount rate. Without discounting the cost is 4.7 cents per kWh. A summary of the commercial air conditioning program energy savings and program costs is presented in Exhibit 4.

Exhibit 4: Commercial Air Conditioning Projections

	Participant Costs	Utility Program Costs (nominal$)	Utility Incentive Costs (nominal$)	Total Costs (excluding incentives) (nominal$)	Annual MWh Savings - TOTAL
2019	$924,753	$308,251	$431,551	$1,233,003	1,079
2020	$943,248	$314,416	$431,551	$1,257,663	2,158
2021	$1,443,169	$481,056	$647,327	$1,924,225	3,776
2022	$1,472,032	$490,677	$647,327	$1,962,710	5,394
2023	$1,501,473	$500,491	$647,327	$2,001,964	7,013
2024	$1,531,502	$510,501	$647,327	$2,042,003	8,631
2025	$1,562,132	$520,711	$647,327	$2,082,843	10,249
2026	$1,593,375	$531,125	$647,327	$2,124,500	11,868
2027	$0	$0	$0	$0	11,868
2028	$0	$0	$0	$0	11,868
2029	$0	$0	$0	$0	11,868
2030	$0	$0	$0	$0	11,868
2031	$0	$0	$0	$0	11,868
2032	$0	$0	$0	$0	11,868
2033	$0	$0	$0	$0	11,868
2034	$1,866,893	$622,298	$647,327	$2,489,190	13,486
2035	$1,904,231	$634,744	$647,327	$2,538,974	15,104
2036	$1,942,315	$647,438	$647,327	$2,589,754	16,723
2037	$1,981,161	$660,387	$647,327	$2,641,549	18,341
2038	$2,020,785	$673,595	$647,327	$2,694,380	19,959
Total	**$20,687,068**	**$6,895,689**	**$7,983,697**	**$27,582,757**	**216,854**

Source: Newport Partners, LLC

[4] To account for continued life of assets beyond the end the program we continued the savings for 10 years after the last programmed expenditure.

Commercial Lighting

This program offers commercial customers a rebate for replacing existing interior lighting fixtures or lamps with high efficiency lamps. The $/kW incentive should make this type of program attractive to commercial customers since there is such variation in lighting types across commercial buildings. However, a significant assumption is the annual kWh savings per participant, which was based on a review of comparable lighting programs. This estimate could be better informed by more granular data on commercial building loads and the breakdown of end use loads for Puerto Rico should this data become available.

Key assumptions underlying the projected costs and energy savings for commercial lighting incentives as an energy efficiency measure include:

- On average two percent of eligible customers participate in the program;
- The program sunsets after ten years;
- There cost of retrofit is $7,800, of which the utility offers a 50% rebate to customer;
- Additional administrative costs are assumed to implement the program; and
- Annual participant energy savings assumed to be 15,000 kWh based on comparable programs in the U.S.

The TRC of this program was calculated to be 3.15 and with a program plus incentives cost of 4.5 cents/kWh[5], this last value calculated by dividing the Present Value of the program + incentives costs at a WACC of 8.5% over the present value of the energy savings using the same discount rate. Without discounting the cost is 2.6 cents per kWh. A summary of the commercial lighting program energy savings and program costs is presented in Exhibit 5.

Exhibit 5: Commercial Lighting Projections

	Participant Costs	Utility Program Costs (nominal$)	Utility Incentive Costs (nominal$)	Total Costs (excluding incentives) (nominal$)	Annual MWh Savings - TOTAL
2019	$9,617,426	$2,466,007	$4,808,713	$12,083,433	18,495
2020	$19,619,549	$5,030,654	$9,617,426	$24,650,203	55,485
2021	$20,011,940	$5,131,267	$9,617,426	$25,143,207	92,475
2022	$20,412,179	$5,233,892	$9,617,426	$25,646,071	129,465
2023	$20,820,422	$5,338,570	$9,617,426	$26,158,992	166,455
2024	$21,236,831	$5,445,341	$9,617,426	$26,682,172	203,446
2025	$21,661,567	$5,554,248	$9,617,426	$27,215,816	240,436
2026	$22,094,799	$5,665,333	$9,617,426	$27,760,132	277,426
2027	$22,536,695	$5,778,640	$9,617,426	$28,315,334	314,416
2028	$22,987,429	$5,894,212	$9,617,426	$28,881,641	351,406
2029	$0	$0	$0	$0	351,406
2030	$0	$0	$0	$0	351,406
2031	$0	$0	$0	$0	351,406
2032	$0	$0	$0	$0	351,406
2033	$0	$0	$0	$0	351,406

[5] To account for continued life of assets beyond the end the program we continued the savings for 10 years after the last programmed expenditure.

SIEMENS

Ingenuity for Life

	Participant Costs	Utility Program Costs (nominal$)	Utility Incentive Costs (nominal$)	Total Costs (excluding incentives) (nominal$)	Annual MWh Savings - TOTAL
2034	$0	$0	$0	$0	351,406
2035	$0	$0	$0	$0	351,406
2036	$0	$0	$0	$0	351,406
2037	$0	$0	$0	$0	351,406
2038	$0	$0	$0	$0	351,406
Total	$200,998,837	$51,538,163	$91,365,547	$252,537,000	5,363,565

Source: Newport Partners, LLC

Street Lighting

Public street lighting accounts for approximately 2 percent of PREPA's load historically. Most of the existing lighting uses high pressure sodium lamps. Conversion to more efficient, LED technology would offer substantial savings estimated to range from 30 to 50 percent savings. The EE savings estimates are assumed to be 40 percent in these projections.

For this measure, a full conversion of the public street lighting to LED light bulbs is assumed to be phased in over five years. Public funding to support this measure is assumed as a key input. Energy savings from this measure are presented in Exhibit 6.

SIEMENS

Ingenuity for life

Exhibit 6: Public Street Lighting Projections

	Annual MWh Savings - TOTAL
2019	25,233
2020	50,634
2021	76,231
2022	102,056
2023	127,998
2024	128,268
2025	128,357
2026	128,186
2027	127,739
2028	126,857
2029	125,768
2030	124,863
2031	124,049
2032	123,302
2033	122,633
2034	122,048
2035	121,547
2036	121,124
2037	120,766
2038	120,603
Total	**2,248,262**

Source: Newport Partners, LLC

Residential Rebuilding Efficiency

Increased efficiency from rebuilding and restoration efforts following the 2017 hurricanes is expected to continue and is estimated for the IRP. As of the Puerto Rico Recovery Plan released in August 2018, an estimated 166,000 residential structures damaged or destroyed still needed to be repaired or rebuilt.[6] A detailed assessment of expected energy savings was performed by McKinsey in 2018. This assessment concluded that savings from reconstruction efforts would reduce load from air conditioning, refrigerators, lighting, water heating and other miscellaneous appliances around 30% relative to the original residences' usage prior to reconstruction. This savings level was applied to PREPA's reported average annual residential account consumption of 3,559 kWh/yr to estimate total expected savings for the balance of reconstruction efforts. The August 2018 Puerto Rico Recovery Plan indicates that the reconstruction of the remaining damaged and destroyed residences is a priority to complete over the next two years. Based on this, much of the rebuilding is assumed to occur by the end of 2019 with the balance to occur in 2020. The projected annual savings from residential rebuilding efforts is presented in Exhibit 7.

[6] http://www.p3.pr.gov/assets/pr-transformation-innovation-plan-congressional-submission-080818.pdf

Exhibit 7: Residential Rebuilding Efficiency Projections

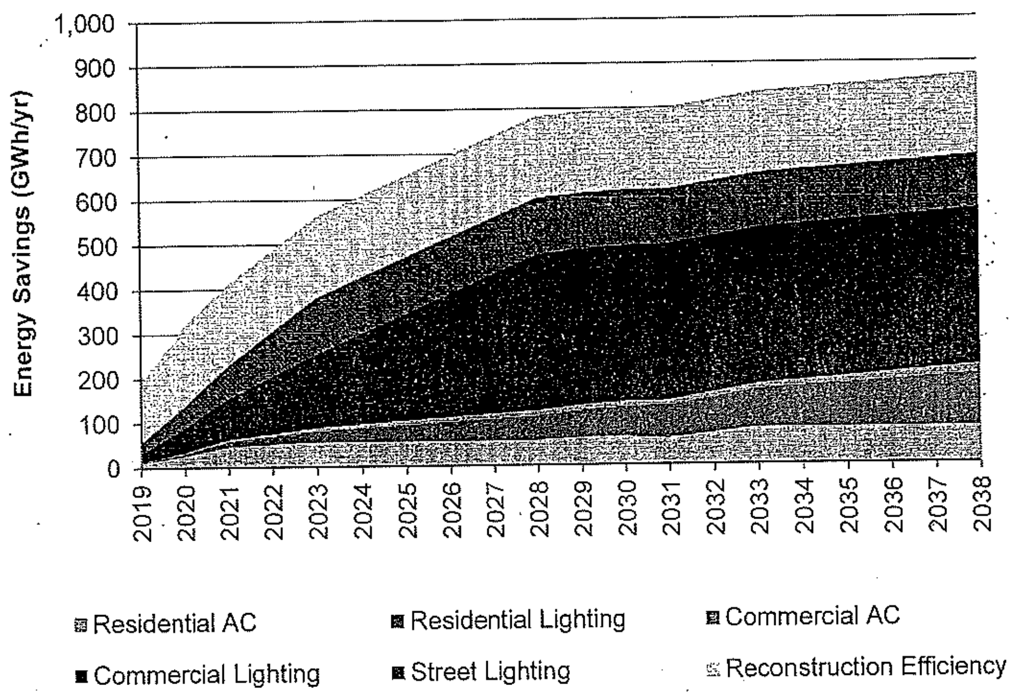
	Annual MWh Savings - TOTAL
2019	135,310
2020	180,413
2021	180,413
2022	180,413
2023	180,413
2024	180,413
2025	180,413
2026	180,413
2027	180,413
2028	180,413
2029	180,413
2030	180,413
2031	180,413
2032	180,413
2033	180,413
2034	180,413
2035	180,413
2036	180,413
2037	180,413
2038	180,413
Total	3,563,159

Source: PREPA, McKinsey, Gouvernement of Puerto Rico

Total Savings – Energy Efficiency

Aggregate annual energy savings from energy efficiency measures is presented in Exhibit 8. These projections reflect participation rates on par with that of other successful programs implemented in other areas in the U.S. and island utility settings as well as measures specific to Puerto Rico associated with hurricane restoration. Total savings projected from these measures are estimated to reach close to 900 GWh annually by the end of the study period.

Exhibit 8: Annual EE Savings by Measure



Source: Newport Partners, LLC, PREPA, Siemens

DEMAND RESPONSE

A variety of demand response measures were considered for the IRP included programmatic demand response for residential customers and for commercial customers. A summary of demand response programs ultimately deemed relevant to include in the IRP is presented in Exhibit 9.

Exhibit 9: Summary of Demand Response Measures

DR Program	Program Description	Rationale	Key Assumptions	Approximate Cost Effectiveness Range (TRC)
Residential Demand Response	Load control of residential A/C systems	This measure provides for residential load management by enabling load control for residential window and mini split A/C units of participating customers via an installed communicating thermostat. Comparable programs are offered by mainland U.S. utilities in Florida, Massachusetts, and in other states as well as in Hawaii.	It is assumed that roughly 85 percent of PREPA residential customers have window or split A/C and would form the base of potential participants.	3 - 4
Commercial Demand Response	Load control during anticipated peak conditions, minimum load to participate	This measure provides for commercial load management by enabling load control for commercial AC and lighting systems. Some programs have also included water heating. This measure can be implemented either automatically where the pre-designated loads are reduced under low-frequency conditions or manually by either utility or on-site operators when peak conditions are anticipated. Utility-controlled load curtailment is the most reliable implementation method. In all cases, the participant is notified in advance that loads will be shed. Most utility programs also require that participants identify a minimum of 50 kW for load curtailment. Usually, events are guaranteed to last no more than 1 hour.	While most commercial demand response programs include some very large commercial and industrial customers, for PREPA, it is assumed that participants would most likely be small and medium-sized commercial establishments – especially in initial program years. Pharmaceuticals are not assumed to participate due to the need for tightly controlled environments all hours of the day. Typical participants well-suited to such a program include hotels/motels, office buildings, non-food retail establishments, and educational facilities.	1 - 2

Source: Newport Partners, LLC

Additional demand response programs considered in the development of this IRP but not ultimately included as a specific projection at this time are listed and summarized below.

- Water pumping – PREPA data indicates approximately 33 MW of water pumping load exists at 48 locations across the island. However, given that the water company is also a government owned public enterprise (the AAA from its name in Spanish) whose role is providing water and sewage services, this program would require intergovernmental agreements, which will take time and are uncertain at this moment. As a conservative assumption, such a DR measure is not included as part of this IRP.
- Standby diesel – The use of customer sited diesel generators as a means of DR for PREPA's system was also considered. The customers where these generators are sited could turn this generation on instead of shedding part of their load, resulting on an effective load reduction as seen from the meter. However, for this to be implemented it, short of splitting the customer

system in two (one connected to PREPA and one disconnected with the local gen), this would require these generators to be upgraded with the appropriate protection and controls to operate synchronized with the grid. Additionally, the customers would need to enter into an interconnection agreement for them to operate in parallel with the grid. Hence, given this uncertainty, this DR measure was not considered for the IRP at this time.

Residential Demand Response

This program sheds residential loads during peak demand periods by curtailing air conditioning operation. Comparable programs are offered by mainland U.S. utilities in Florida, Massachusetts, and in other states as well as in Hawaii.

Key assumptions underlying the projected costs and peak energy savings for residential demand response include:

- On average one percent of eligible customers participate in the program;
- There is no additional cost to participants to participate;
- Utility incurs a one-time cost of $200 per customer based on reported costs for similar programs in Florida and Hawaii to install Wi-Fi monitored thermostat and set up the customer account;
- Additional administrative costs are assumed to implement and manage the program on an ongoing basis;
- On average, customers receive $100 per year in payments for peak demand reductions; and
- Net peak energy load reductions per participating customer assumed to be 1.2kW based on average power consumption for 1 ton window units and 1 ton split units.

A summary of the residential demand response program peak load savings and costs is presented in Exhibit 10.

Exhibit 10: Residential Demand Response Projections

	Participant Costs	Non-Reoccurring Utility Cost	Reoccurring Utility Cost	Utility Incentive Costs	Total Costs (excluding incentives)	Annual kW Reduction:
2019	$0	$2,275,759	$1,820,608	$1,137,880	$4,096,367	13,655
2020	$0	$2,337,524	$3,355,635	$2,056,149	$5,693,158	24,674
2021	$0	$2,400,964	$4,658,969	$2,798,785	$7,059,933	33,585
2022	$0	$2,466,126	$5,774,619	$3,400,971	$8,240,746	40,812
2023	$0	$2,533,057	$6,738,535	$3,890,853	$9,271,592	46,690
2024	$0	$2,601,804	$7,580,088	$4,290,949	$10,181,891	51,491
2025	$0	$2,672,417	$8,323,285	$4,619,274	$10,995,702	55,431
2026	$0	$2,744,946	$8,987,757	$4,890,240	$11,732,704	58,683
2027	$0	$2,819,444	$9,589,565	$5,115,376	$12,409,009	61,385
2028	$0	$2,895,964	$10,141,856	$5,303,907	$13,037,820	63,647
2029	$0	$2,974,560	$10,655,403	$5,463,214	13629963.22	65,559
2030	$0	$3,055,290	$11,139,041	$5,599,199	$14,194,330	67,190

	Participant Costs	Non-Reoccurring Utility Cost	Reoccurring Utility Cost	Utility Incentive Costs	Total Costs (excluding incentives)	Annual kW Reduction:
2031	$0	$3,138,210	$11,600,025	$5,716,588	$14,738,236	68,599
2032	$0	$3,223,381	$12,044,326	$5,819,160	$15,267,707	69,830
2033	$0	$3,310,864	$12,476,861	$5,909,938	$15,787,725	70,919
2034	$0	$3,400,721	$12,901,695	$5,991,344	$16,302,416	71,896
2035	$0	$3,493,016	$13,322,196	$6,065,311	$16,815,213	72,784
2036	$0	$3,587,817	$13,741,166	$6,133,391	$17,328,983	73,601
2037	$0	$3,685,190	$14,160,943	$6,196,823	$17,846,134	74,362
2038	$0	$3,785,206	$14,583,495	$6,256,600	$18,368,701	75,079
Total	**$0**	**$59,402,261**	**$193,596,069**	**$96,655,952**	**$252,998,330**	**1,159,871**

Source: Newport Partners, LLC

Commercial Demand Response

This program sheds commercial loads during peak demand periods by curtailing air conditioning and lighting operation. While most commercial demand response programs include some very large commercial and industrial customers, for PREPA, it is assumed that participants would most likely be small and medium-sized commercial establishments, especially in initial program years.

Key assumptions underlying the projected costs and peak energy savings for commercial demand response include:

- On average annual participation growth of 0.4 percent of eligible customers participate in the early years of the program, slowing to 0.2 percent annual increase after the first five years of the program due to saturation of interest. (Annual participation growth rate in commercial DR programs is particularly dependent upon the types and sizes of commercial establishments in the service territory as well as upon the characteristics of generating capacity and distribution.)
- There is no additional cost to customers to participate;
- Utility incurs a one-time cost of $400 per customer based on reported costs for similar programs in Florida and Hawaii to install Wi-Fi monitored thermostats, lighting controls, communication software and set up customer account;
- Additional administrative costs are assumed to implement and manage the program on an ongoing basis;
- On average, customers receive $3,000 per year in payments for peak demand reductions; and
- Net peak energy load reductions per participating customer are assumed to be 6 kW.

A summary of the commercial demand response program energy savings and costs is presented in Exhibit 11.

SIEMENS
Ingenuity for life

Exhibit 11: Commercial Demand Response Projections Revised

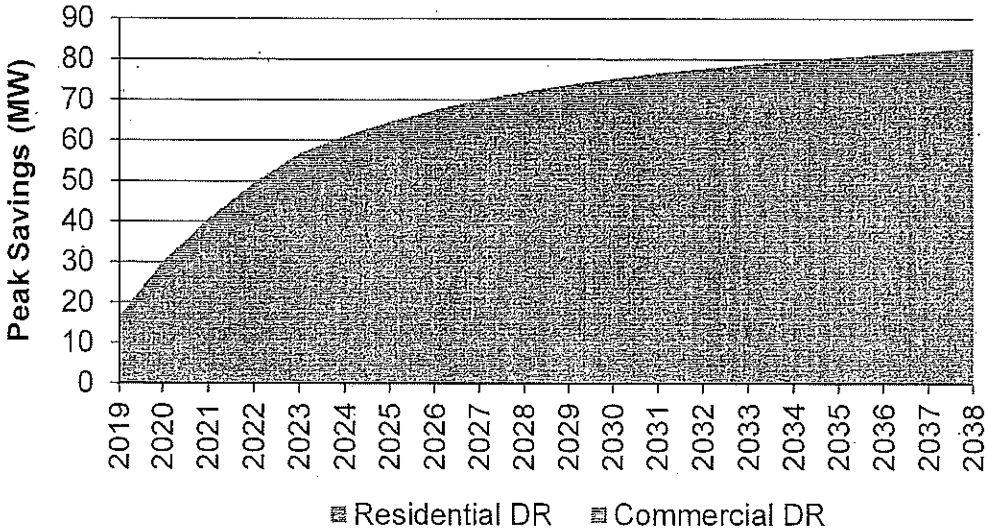
	Participant Costs	Non-Reoccurring Utility Cost	Reoccurring Utility Cost	Utility Incentive Costs	Total Costs (excluding incentives)	Annual kW Reduction:
2019	$0	$197,281	$986,403	$1,479,604	$1,183,683	2,959
2020	$0	$201,226	$1,811,035	$2,663,287	$2,012,261	5,327
2021	$0	$205,251	$2,504,058	$3,610,234	$2,709,309	7,220
2022	$0	$214,165	$3,114,138	$4,401,783	$3,328,304	8,804
2023	$0	$218,449	$3,633,380	$5,035,022	$3,851,829	10,070
2024	$0	$111,409	$3,521,882	$4,784,816	$3,633,291	9,570
2025	$0	$113,637	$3,442,041	$4,584,651	$3,555,678	9,169
2026	$0	$115,910	$3,388,254	$4,424,519	$3,504,164	8,849
2027	$0	$118,228	$3,355,955	$4,296,413	$3,474,183	8,593
2028	$0	$120,592	$3,341,422	$4,193,928	$3,462,014	8,388
2029	$0	$123,004	$3,341,622	$4,111,941	$3,464,626	8,224
2030	$0	$125,464	$3,354,086	$4,046,351	$3,479,550	8,093
2031	$0	$127,974	$3,376,802	$3,993,878	$3,504,776	7,988
2032	$0	$130,533	$3,408,137	$3,951,901	$3,538,670	7,904
2033	$0	$133,144	$3,446,759	$3,918,319	$3,579,903	7,837
2034	$0	$135,807	$3,491,589	$3,891,453	$3,627,396	7,783
2035	$0	$138,523	$3,541,751	$3,869,960	$3,680,274	7,740
2036	$0	$141,293	$3,596,535	$3,852,766	$3,737,829	7,706
2037	$0	$144,119	$3,655,369	$3,839,011	$3,799,488	7,678
2038	$0	$147,002	$3,717,789	$3,828,007	$3,864,790	7,656
Total	**$0**	**$2,963,011**	**$64,029,006**	**$78,777,843**	**$66,992,016**	**157,556**

Source: Newport Partners, LLC

Total Savings – Demand Response

Aggregate peak energy savings from demand response measures is presented in Exhibit 12. These projections reflect participation rates on par with that of other successful programs implemented in other areas in the U.S. and island utility settings.

Exhibit 12: Annual Peak Energy Savings from DR Programs



Source: Newport Partners, LLC

Overall Energy Savings from Demand-Side Resources

Regulation 9021 defines a target for the IRP to achieve two percent incremental energy savings per year for at least ten years.[7] Energy savings from new energy efficiency measures developed are projected to range from between 0.3 percent and 1.25 percent incremental annual savings over the first ten years of the study period, from 2019 to 2028. Demand response programs contribute additional savings to peak demand, on average 0.15% of peak load over the same ten year period. Additional demand side savings from government end use and existing programs is expected to also contribute towards the prescribed two percent incremental energy savings goal.

[7] Regulation 9021, Section F 3 e