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COMMONWEALTH OF PUERTO RICO

PUERTO RICO ENERGY COMMISSION

IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN	NO. CEPR-AP-2018-0001 **SUBJECT:** PREPA'S INFORMATION SUBBMISSION AND ANSWERS IN RESPONSE TO COMMISSION'S ORDER

INFORMATION SUBMISSION AND ANSWERS TO REQUEST OF INFORMATION

TO THE HONORABLE PUERTO RICO ENERGY COMMISSION:

COMES NOW the Puerto Rico Electric Power Authority ("PREPA") and respectfully submits to the honorable Puerto Rico Energy Commission (the "Commission") PREPA's answers to the requirement of information on Appendix A of the Commission's Resolution and Order dated August 8, 2018.

RESPECTFULLY SUBMITTED,

IN SAN JUAN, PUERTO RICO, THIS 13 DAY OF AUGUST, 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 August 13, 2018, I have sent the above INFORMATION SUBMISSION AND ANSWERS TO REQUEST OF INFORMATION to the Puerto Rico Energy Commission through its Clerk via email to secretaria@energia.pr.gov and bmulero@energia.pr.gov; and to the office of the Commission's internal legal counsel via email to legal@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

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1. Section 1.03. Explain PREPA/Siemens overarching approach for determining an appropriate planning reserve margin ("PRM") to meet load, accounting for historically high generation outage rates and understandable uncertainty for near- and longer-term projected peak load levels. Will it reflect conventional "loss of load expectation" constructs, or a variation on that construct? Will it use conventional threshold metrics (such as one-day-in-ten-years loss of load events) or more relaxed metrics? Is it PREPA/Siemen's intention that the IRP process will seek to meet a resource requirement driven by an estimation of a specific planning reserve margin? Please discuss.

The PRM is to be determined to achieve compliance with a resource adequacy criteria that results in acceptable service to customers. In the US this criteria is typically a "Loss of Load Expectation" ("LOLE") of 1 in 10 years (in other words, 1 hour per 10 years in which available electricity production cannot meet daily peak demand), which can be practically achieved on the mainland given the fact that the size of the interconnected system and the size of the largest units are a small fraction of the system peak load. In Puerto Rico, the largest units represent an important percentage of the peak (15% or more) and to try to apply the same reliability criteria would result in large reserve margins to be required. PREPA proposes to us its criteria of maximum 4 lost load hours per year of (Loss of Load Hours or "LOLH") (hours per year in which a system's hourly demand is projected to exceed generating capacity), complemented by Energy Not Served (ENS) and based on this determine the required PRM. For this, we will first make a Capacity Expansion Plan with an initial PRM based on unforced capacity of 30% (approximately twice the largest unit) and then verify the LOLH and ENS, and if the criteria is not met then we will adjust the PRM upwards or downwards until expected compliance is met.

It should be noted that we expect that the PRM will change over_time as larger units are retired and the system evolves to a supply based more on smaller distributed units.

2. Explain if or how the results, assumptions, and approach contained in the publicly available white paper "Resilient by Design: Enhanced Reliability and Resiliency for Puerto Rico's Electric Grid" (Siemens) reflects PREPA's current perspective on its expectations for the IRP analysis. Discuss as appropriate.

This document was prepared by Siemens before they were selected to conduct the IRP and based on high level models and without the benefit of the models and information currently available to them. Siemens developed that document to contribute their view on how the system could look in the long term given the lessons learned from hurricane Maria, the reduction of costs of renewable generation and storage, and the opportunity that new projects in the island would benefit from them. On a high level, the concept of minigrids, and the increased role of renewable and storage remains the same; however, everything else starting from the number of minigrids to the resource composition is currently undergoing evaluation and it is likely to be materially different.

3. In what ways will any costs associated with potential development of natural gas import capacity in the north or the south be explicitly incorporated into the capital and/or operating and/or fuel costs of new gas-fired resource options available to the IRP model for selection as part of a least-cost portfolio?

Capital and operating costs of fuel infrastructure will be considered by the Long Term Capacity Expansion model together with the cost of developing the generation. Therefore when assessing these options all costs are included.

4. Refer to answers provided to Question 8 in the August 1, 2018 Compliance Filing. Include the August 1, 2018 Fiscal Plan for PREPA as part of the discussion of legislative changes that could impact PREPA's system and the IRP Update.

PREPA agrees that the 2018 Fiscal Plan is an important factor to be considered in the IRP as requested in Question 8.

5. Refer to answers provided to Question 12 and Question 15 in the August 1, 2018 Compliance Filing:

   a. Include in electronic format the specific deterministic annual load forecast for years 2019-2038, for each of a reference, high and low forecast, including coincident peak demand and annual energy consumption, in total and for each customer class. Provide these data on a monthly basis if available.

   b. Include as forecast components (if/as available) the extent to which the above forecast in Part (a.) (especially for trends over time) includes explicit estimation of changing economic factors that affect overall consumption and peak demand. This would include the specific quantitative estimate for "Quantum Distribution: Additional Variability" as noted in the response.

   c. Include as forecast components (if/as available) the extent to which the above forecast in Part (a.) includes the effect of any projected naturally occurring energy efficiency, or energy efficiency expected to result from existing and expected building codes, and appliance standards.

   d. Include as forecast components (if/as available) the extent to which the above forecast in Part (a.) includes technical losses. Differentiate between transmission and distribution system losses. Include technical loss components as they exist at peak load conditions, and on an average annual energy basis.

   e. Include as forecast components (if/as available) the extent to which the above forecast in Part (a.) includes non-technical losses. Include non-technical loss components as they exist at peak load conditions, and on an average annual energy basis.

   f. Include in electronic format historic peak demand and energy consumption, for the past ten years, in total and for each customer class. Include monthly estimates for at least 2017.

PREPA will provide the information above as requested as soon as it is finalized and become available. We expect that most of the items requested will be available, however, there may be some elements that are not part of the forecast (e.g., naturally occurring energy efficiency ("EE")) and are treated elsewhere.

6. Refer to answers provided to Question 16 and Question 17, and Question 25 in the August 1, 2018 Compliance Filing:

    a. Provide a forecast for "future energy efficiency programs", in the same format and categorization as requested above in Question 5, Part (a.). [i.e., annually, for coincident peak demand and energy, and by customer class, for 2019-2038].

    b. Provide projected coincident peak demand savings, annual energy savings, and costs for both energy efficiency and demand response resources to be used in the IRP. Provide this information for each of the years 2019-2038. Confirm that this information is the same as what was described in the response to Question 25 in the August 1, 2018 Compliance Filing.

    c. Fully describe how the costs and savings associated with "future energy efficiency programs" will be characterized in the IRP modeling process; in particular, state if such costs and savings will be used to modify the load inputs or will be made available as resources to meet load projections made without consideration of the effect of these resources.

    d. Fully describe how the IRP modeling will account for technical loss savings on a coincident peak demand basis and on an annual energy basis for any "future energy efficiency programs".

    e. Provide a forecast for the effect on annual energy and coincident peak demand for deployment of behind-the-meter distributed generation, annually for the period 2019-2038. Specifically, explain how this will be treated in the IRP modeling. Note if the load forecasts requested above in Question 5, Part (a.) include or exclude such distributed generation effects on "net load" seen on the grid.

The EE studies are still underway and as soon they are available will be provided. This includes answers to items "a", "b", "c" (however, we expect that EE will be a load modifier). As to "d", by reducing the load the impact on technical losses will be accounted for in the modeling.

On question "d", PREPA is developing a forecast of behind the meter ("BTM") generation that will be modeled as a resource geographically distributed but "lumped" in a number of representative buses. This will be made available to PREC as soon is completed.

7. Refer to answers provided to Question 19 in the August 1, 2018 Compliance Filing. Provide a list of the utility-owned and non-utility-owned existing resources to be considered in the IRP, with at least the following attributes included:

    a. Nameplate capacity.

    b. Current "summer" or peak period capacity.

    c. Expected annual utilization (capacity factor) or expected annual energy production.

    d. Fuel type or types.

    e. Current operational status.

    f. Projected forced and planned outage rates (for all fossil resources) to be used in the IRP, with variation by year if anticipated changes to current forced and planned outage rates.

    g. Anticipated contribution to peak load requirements (as a % of nameplate capacity) for hydro, wind and solar PV resources for resource adequacy purposes.

PREPA will provide a memo with answers to "a" to "f".

PREPA's peak is forecasted to be a night peak, hence the contribution of wind and solar at the night peak is insignificant. Hydro depends on the selected plan. We have as an option the possibility of repairing the existing hydro, in which case their availability would be improved and we expect an unforced capacity in the 90% of nameplate range.

8. Refer to answers provided to Question 23 in the August 1, 2018 Compliance Filing.

    a. State which zones the IRP will define for the "zonal level" indicated.

    b. Confirm, or explain otherwise, that these zones are the same as the "minigrids" noted on page 15 of Attachment 1 of the August 1, 2018 Compliance Filing.

    c. What are the projected transmission limitations between these zones, at this time, and as projected over the early years of the IRP planning horizon?

    d. What is PREPA's current projections for the value of lost load (VOLL) to be used in the IRP, and does VOLL vary across the customer sectors?

    e. What are the sources of information used to project VOLL levels?

The zonal level considered corresponds to the 8 zones into which the system is modeled in PSS®E, further subdivided to represent the minigrids. This implies for example that the zone of Mayaguez will be possibly separated in two (North and South) and Caguas in two; Caguas and Cayey.

The transmission limitations are under review; however, in the forthcoming presentation of August 14th, we show our current estimation.

The VOLL assessment is underway. We are using public information including the Interruption Cost Estimate (ICE) Calculator developed by Lawrence Berkeley National Laboratory and Nexant, Inc. (https://icecalculator.com/home)

9. Refer to answers provided to Question 24 in the August 1, 2018 Compliance Filing.

    a. What is the current status of the ability of the distribution grid to support any particular level of distributed generation?

PREPA is currently assessing its system to determine the investments necessary (mostly voltage regulation and conversion to 13.2 kV, but also including protection and control upgrades). These studies are ongoing and are not expected to be completed before the end of the IRP. In the IRP, however, the investments will be assumed to be in place and not being a limiting factor.

10. Refer to answers provided to Question 26 in the August 1, 2018 Compliance Filing. 2 0 1

    a. Specify the exact battery energy storage system (BESS) options (e.g., type, size, duration, intended use, and performance parameters) to be available as options in the IRP.

    b. Provide PREPA's estimate of the capital costs, and any other costs to be modeled in the IRP, for all battery resource options.

    c. Provide the projected cost trajectory reflecting any changes to estimated costs over time to be included in the BESS resource attributes to be modeled in the IRP.

    d. Describe (as applicable) how the IRP will model any technical loss benefits that may accrue from BESS resources installed close to load, in particular during peak system loading periods.

BESS options to be considered consist of utility scale units possibly in blocks of 20 MW, however, this is not prescriptive. Also we will be considering options of 2, 4, and up to 6 hour storage. A memo with new resources and costs will be provided as soon as available (currently under review).

The projected cost trajectory is included in the memo and it is based on NREL's recently published NREL's Annual Technology Baseline (https://atb.nrel.gov/).

The BESS are expected to be a critical component of the minigrid concept and hence will be deployed close to the load. Therefore, the reduction in losses and hence the reduction in generation variable operating costs will be captured during the modeling of the portfolios that contain them using PROMOD®.

11. Refer to answers provided to Question 30 in the August 1, 2018 Compliance Filing.

a. Explain PREPA's rationale for including a zero price for carbon emissions in its base case.

b. Are there any technical (modeling input) hurdles to incorporating a non-zero carbon emissions price in each of the four scenarios under consideration?

c. In what ways are basis costs (from Henry Hub prices) to be explicitly considered in the IRP for delivering natural gas to Puerto Rico? Provide any specific estimates for the basis between Henry Hub and Puerto Rico to be used in the IRP modeling.

Answer to a & b:

No CO2 price is assumed in the IRP base case noting that at this time there is no existing or proposed policy capping or otherwise regulating CO2 emissions from power generators in Puerto Rico. Compliance with known policies including MATS and the Puerto Rico RPS are expected to indirectly drive emission reductions of PREPA's generation fleet over the study period. A price on carbon is included as a potential sensitivity to include in the IRP analysis. The price of carbon proposed is based on a consensus of publicly available U.S. carbon price forecasts which starts around $10/ton in 2022 and increases to around $80/ton (nominal$).

There are no technical / modeling hurdles to incorporating a non-zero carbon price in the scenarios.

Answer to c

The benchmark Henry Hub forecast serves as the foundation for the delivered-to-Puerto Rico natural gas price outlook. The basis costs to be added to Henry Hub prices in order to provide delivered fuel prices are explicitly considered in the IRP in the following way. Siemens reviewed two cost components to be added to the Henry Hub price: liquefaction costs and shipping costs for U.S. Gulf Coast LNG delivered from the operational Sabine Pass export terminal. Sabine Pass liquefaction tolling fees are estimated to be $2.83/MMBtu, which equates to a 10% IRR. To this liquefaction cost, we then add delivery charges. Shipping costs from Sabine Pass to several locations, including Spain, Chile, India, South Korea, Japan, were used as a basis to calculate a shipping cost of $0.50/MMBtu to Puerto Rico (assuming 2,300 nautical miles one-way and 13 days travel). Finally, a premium is added to the shipping costs because we expect LNG ship sizes to Puerto Rico will be smaller than the 170,000 m3 size that is typical for Sabine Pass. When accounting for all of these adders ($2.83 + $0.50 + premium), we arrive at the conservative $4.00/MMBtu basis cost to be added to the Henry Hub price outlook in order to develop the delivered-to-Puerto Rico natural gas fuel cost. We recognize that the Jones Act is a hindrance to LNG delivered from the U.S. Gulf Coast to a U.S. territory. Currently, more than 90% of LNG delivered to Puerto Rico comes from Trinidad & Tobago, which is only 700 nautical miles distant. Nevertheless, the Henry Hub is the best and most liquid index point for delivered LNG costs and we have tried to be conservative in our cost estimate.

12. Refer to answers provided to Question 32 in the August 1, 2018 Compliance Filing.

a. It appears that PREPA is planning to use the same underlying load forecast for each of the four scenarios. Please confirm or explain otherwise.

b. If it is true that the same load forecast is to be used, explain how that approach comports with Section 2.03 (C)(2) which describes a need to prepare low, reference, and high load forecast cases.

c. Provide the statistical parameters associated with the load forecast planned to be used in developing the stochastic analysis for each of the scenarios.

d. The response to Question 32 states "The model will be run with a variety of generation options to determine the least cost portfolio for each Scenario". Explain how non-generation options (e.g., demand response, energy efficiency, battery storage) will be available to the IRP model to be ~~selected as~~ part of a least cost portfolio in each of the four scenarios.

Our central approach is to identify how the uncertainty on the load forecast will affect the short term decisions (first 5 years) and if necessary what modifications would need to be made. For this the central load forecast will be used to formulate an initial Capacity Expansion Plan associated with each scenario. Then this plan will be subject to 200 simulations where the load forecast will be changed reflecting the uncertainties on the underlying assumptions, e.g., GDP and Population forecast. These forecasts are designed to include the expected extremes (optimistic and pessimistic) of the materialization of the future load and will provide information on impact on the Capacity Expansion Plan. Based on this we obtain information we will modify if required the Capacity Expansion Plan. ,

PREPA is finalizing a memo with the load forecast details which will provide information on how the stochastic analysis was developed. This memo will be provided as soon is finalized.

Energy Efficiency will be modeled as a reduction in the gross load. Demand response and battery storage are resources available to the IRP model for optimization.

13. Refer to answers provided to Question 36 in the August 1, 2018 Compliance Filing.

a. Is PREPA/Siemens planning to directly use the long-term capacity expansion (LTCE) feature of Aurora when producing any, each or all of the scenario results for a least cost expansion plan?

b. The response to Question 36 states that LTCE is utilized by Aurora "As part of the screening analysis". Exactly how is resource screening analysis planning to be incorporated as part of the IRP?

Yes, we plan to use the LTCE feature for all of the Scenario assessment and results. Screening in this context refers to the assessment of the available options and selection of the optimal mix.