**GOVERNMENT OF PUERTO RICO**
**PUBLIC SERVICE REGULATORY BOARD**
**PUERTO RICO ENERGY BUREAU**

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| IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN | **CASE NO.:** CEPR-AP-2018-0001<br><br>**SUBJECT:** PREPA's Cover Filing for Responses to Energy Bureau 1st Set of ROIs and Confidentiality Designations, and Motion for More Time on Certain Items |

**PREPA's Cover Filing for Responses to Energy Bureau 1st Set of ROIs and Confidentiality Designations and Motion for More Time on Certain Items**

The Puerto Rico Electric Power Authority ("PREPA") hereby respectfully submits to the Puerto Rico Energy Bureau (the "Energy Bureau") PREPA's Cover Filing for Responses to Energy Bureau 1st Set of ROIs and Confidentiality Designations, and Motion for More Time on Certain Items. This filing relates to the Energy Bureau's "1st Requirement of Information [ROIs] to PREPA" issued on July 11, 2019. The Energy Bureau's 1st set of ROIs originally set a due date of July 22, 2019, for PREPA's responses to these ROIs, but the Energy Bureau's Resolution and Order of July 23, 2019, extended the due date to August 2, 2019, at 12:00 p.m. PREPA also separately is filing its related Motion for Confidential Treatment of Portions of Its Responses to ROIs.

**Responses**

The Energy Bureau's 1st Set of ROIs includes 56 ROIS plus numerous subparts. PREPA's responses are too voluminous to file in hard copy and therefore are being provided on a USB drive.

**Confidentiality Designations**

PREPA designates the following responses, subparts of responses, or documents as confidential:

- Technical Information (i.e., CEII) - PREB-PREPA-01-06 -- Confidential-PREPA ROI_1_6 Attach 1.docx; Confidential-PREPA ROI_1_6 Attach 2.xlsx
- Technical Information - PREB-PREPA-01-16 -- Confidential-PREPA ROI_1_16 Attach 1.pdf; Confidential-PREPA ROI_1_16 Attach 2.pdf; Confidential-PREPA ROI_1_16 Attach 3.pdf, Confidential-PREPA ROI_1_16 Attach 4.xlsx; Confidential-PREPA ROI_1_16 Attach 5.xlsx; Confidential-PREPA ROI_1_16 Attach 6.xlsx
- Technical Information - PREB-PREPA-01-23 -- Confidential-PREPA ROI_1_23 Attach 4.pdf
- Trade Secret - PREB-PREPA-01-39 -- Confidential-PREPA ROI_1_39 Attach 1.pdf
- Trade Secret - PREB-PREPA-01-56 -- Confidential-PREPA ROI_1_56 Attach 1.xlsx

PREPA is supporting these designations though its separate Motion for Confidential Treatment of Portions of Its Responses to ROI.

**Motion for More Time on Certain ROI Responses**

Finally, PREPA respectfully requests an extension of time with respect to certain of the ROI responses. More specifically, PREPA requests an additional 5 working days for the following ROIs or ROI subparts:

- PREB-PREPA-01-04 – The information is not available as of this moment; PREPA has reached out to the corresponding party and will provide the required information as soon as it is available.
- PREB-PREPA-01-05 – Response requires additional simulations by Siemens. Will be provided as soon as available.
- PREB-PREPA-01-28 – The information is not available as of this moment; PREPA has reached out to the corresponding party and will provide the required information as soon as it is available.
- PREB-PREPA-01-29 – The information is not available as of this moment; PREPA has reached out to the corresponding party and will provide the required information as soon as it is available.
- PREB-PREPA-01-34 (a). – The information is not available as of this moment; PREPA has reached out to the corresponding party and will provide the required information as soon as it is available.

PREPA acknowledges that the Energy Bureau has indicated that motions for more time generally should be filed at least one day in advance of a due date. PREPA has been working to try to assemble a complete set of responses by today, and only determined this morning that it would need to request more time for certain items.

**WHEREFORE**, the Puerto Rico Electric Power Authority respectfully requests that the honorable Puerto Rico Energy Bureau accept PREPA's ROI responses and approve its confidentiality designations, and grant more time for certain ROI responses as requested.

RESPECTFULLY SUBMITTED,

IN SAN JUAN, PUERTO RICO, THIS 2nd DAY OF AUGUST, 2019

**PUERTO RICO ELECTRIC POWER AUTHORITY**

**I HEREBY CERTIFY** that the foregoing Filing (including its attachments provided on a USB drive), was, on August 2, 2019, filed in person at the office of the Clerk of the Puerto Rico Energy Bureau; and, that the Filing (without its attachments) was sent via email to the Puerto Rico Energy Bureau staff through email to secretaria@energia.pr.gov and viacaron@energia.pr.gov; and to legal@energia.pr.gov. With respect to approved or pending intervenors, on August 2, 2019, PREPA will mail a copy of this Filing. Since a number of intervention petitions and orders were filed or issued within the last 24 hours, the assembly of this mailings and USB drives will take some time and the mailing will occur as soon as practicable.

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**COMMONWEALTH OF PUERTO RICO**
**PUBLIC SERVICE REGULATORY BOARD**
**PUERTO RICO ENERGY BUREAU**

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| IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN | NO. CEPR-AP-2018-0001<br><br>**SUBJECT:** REQUIREMENTS OF INFORMATION |

**PREPA'S RESPONSES TO THE ENERGY BUREAU'S FIRST SET OF REQUIREMENTS OF INFORMATION**

**TO: THE PUERTO RICO ENERGY BUREAU**
Through:
viacaron@energia.pr.gov
secretaria@energia.pr.gov
legal@energia.pr.gov

**FROM: PUERTO RICO ELECTRIC POWER AUTHORITY**
Through the General Counsel
Astrid I. Rodriguez Cruz, Esq.

COMES NOW the Puerto Rico Electric Power Authority ("PREPA"), and as per the Puerto Rico Energy Bureau ("Energy Bureau" or "PREB") First Set of Requirements of Information dated July 11,2019 (the "Request"), pursuant to the provisions of Article VIII of Regulation No. 8543, Regulation on Adjudicative, Notice of Noncompliance, Rate Review and Investigation Proceedings, under the captioned matter, submits these answers and/or documents in response to the Request.

PREPA objects to any Requirement of Information ("ROI") that calls for information or documents that are not in the possession, custody, or control of PREPA.

For ease of reference, the questions and requirements as set forth in the Request are herein transcribed and shown in bold previous to each answer.

**PREB-PREPA-01-01** **Data collection required by Section VII.C.3 of the Energy Bureau's Final Resolution and Order in Case No. CEPR-AP-2015-0002:**

**a) Provide the "Hourly Generation Report" files submitted by PREPA on June 14, 2019 in their native Excel format, preferably combined for all dates, if able. Provide the data for at least the dates from July 1, 2018 through June 30, 2019.**

**b) Provide the additional information required by this Section as it becomes available, as indicated on page 7 of PREPA's June 14, 2019, Cover Filing, Updated List of Documents Filed or Submitted, and Motions.**

The following responses were provided by Alfonso Baretty Huertas, Acting Head Planning and Research Division, Puerto Rico Electric Power Authority (PREPA). Alfonso Baretty Huertas certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-01 a) The requested files are not available at this moment. PREPA will provide the files as soon as they become available.

PREB-PREPA-01-01 b) Refer to files PREPA ROI_1_01 Attach 1.pdf and PREPA ROI_1_01 Attach 2.pdf for the 2016 and 2017 emissions reports corresponding to Section VII.C.3 item c) of the Energy Bureau's Final Resolution and Order in Case No. CEPR-AP-2015-0002.

**PREB-PREPA-01-02** **Provide a corrected version of Exhibit 8-75: Scenario 3 Results of the IRP Main Report that shows cases S3S2S5B and S3S2S8B to have the same resource plans as case S3S2B. Confirm that the results presented for these cases are correct.**

The following response was provided by Marcelo Saenz, Engagement Manager, Siemens. Marcelo Saenz certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** The results presented for both cases are correct. Both cases are sensitivities that did not require to run the Long-term Capacity Expansion. In other words, the expansion plan is the same as S3S2B.

**PREB-PREPA-01-03** **The questions below are related to the MiniGrids approach. For each question below, in addition to the qualitative or written responses provide any quantitative analysis conducted that relates to the answer.**

**a) Describe in detail the process that PREPA used to determine the boundaries of each proposed minigrid.**

**b) Why did PREPA select the use of 8 MiniGrids (as opposed to some other number)?**

c) **Refer to Exhibit 2-1 in Appendix 1. Provide a table delineating the light green, yellow (brown), red, and blue lines and listing for each color (i) the total mileage, (ii) voltage, and (iii) specific reasoning for estimate of time-to-repair or time-to-restore.**

d) **Did PREPA consider joining together multiple areas into fewer, larger MiniGrids? If so, what was the reason they were not joined? If not, why did PREPA not consider this option?**

e) **Did PREPA consider separating any MiniGrids into smaller MiniGrids? If so, what was the reason they were not separated? If not, why did PREPA not consider this option?**

f) **Did PREPA conduct any optimization analyses associated with its Minigrid plan beyond consideration of value of lost load effects, and estimation that a month-long outage of major transmission assets must be mitigated? If so, provide such analyses.**

The following responses were provided by Yan Du, Staff Consultant, Siemens, and Brenda Pérez Román, Acting Manager, PREPA. Yan Du and Brenda Pérez Román certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-03 a) The boundary of MiniGrids should not be considered static, MiniGrids boundaries are flexible, the process we used was to identify the lines down to 38 kV that are likely to be out in the long term and to made sure that under this worst scenario there is enough internal resources to supply the critical and priority loads and these resources can get access to the load. The MiniGrids largely match PREPA's operating areas which has logistic advantages. We provide a list of lines identified as defining the borders as a separate attachment. (refer to PREPA ROI_1_3 Attach 1.xlsx). Actual separation after major event may look different and as much as PREPA is able to recover the interconnection between the MiniGrids faster or ride through the event, then the impact to the system will be minimized and the operation back to normal conditions will be faster. However, the MiniGrids design provides safeguard against the vulnerable lines taking longer time to recover. The importable aspect to keep in mind is that each MiniGrid is designed with a core that ensures that the critical loads and priority loads can be reconnected back to local generation. The core can be located by examining the investment on the Minigrid backbones. Of course, further assessment can be done to determine the probability of each individual line of failing and estimated time to repair. However, at this stage we relied upon PREPA's engineering and operation experience and very importantly we assumed that the lines had been repaired and brought back up to code otherwise other vulnerable lines would be affected.

The following responses were provided by Yan Du, Staff Consultant, Siemens. Yan Du certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-03 b) Eight MiniGrids were the results of the analysis presented above. For instance, Mayaguez is a single operation zone however it could split into North and South zones and the MiniGrids concept ensures there will resources in the north. These resources will minimize the impact to the loads in the time it takes to reconnect either to the generation in the east or south. Also, interconnecting already energized electrical islands during restoration, e.g. Mayaguez North and South, it is a much safer and faster than energizing cold load. On the other hand, the MiniGrids of San Juan and Bayamon although they are two operational zones we are considering one Minigrid because they are well interconnected.

PREB-PREPA-01-03 c) Please refer to PREPA ROI_1_3 Attach 1.xlsx for detailed information on the map in reference.

PREB-PREPA-01-03 d) As discussed above the MiniGrids boundaries are not static but were defined with the objective of identifying the core with respect of the generation. We did consider the desirability of MiniGrid growing faster into larger MiniGrids and for that we identify some investment that were recommended for MiniGrid interconnection and growth.

PREB-PREPA-01-03 e) Yes, we did, and we identified the areas that could not be easily recovered, and we recommended microgrids to reconnect them.

PREB-PREPA-01-03 f) Not at this time, however the LTCE analysis using Strategy 1 vs 2 identified the differences in NPV were relatively small except for Scenario 5 that placed large amount of generation in the south. Moreover, as indicated above the transmission investment associated with Minigrids were those necessary to interconnect the local generation to the critical and priority loads. We realize that individual transmission investments inside the MiniGrids e.g. those for the MiniGrid backbone could be fine-tuned and an optimization made balancing on one hand the cost of transmission versus the expected VoLL on the other. This analysis could be carried out if necessary but based on previous results we don't expect significant differences.

**PREB-PREPA-01-04** **The questions below are related to the ESM Plan.**

**a) Why did PREPA include as many as 18, 23 MW peaker resources in its ESM plan? Provide a quantitative justification for the number of peaking resources considered.**

**b) Provide the documents that PREPA used to define the fixed resources in the ESM Plan. These documents may include, but should not necessarily be limited to, documents related to proposals submitted to the Public Private Partnerships (P3) Authority.**

**c) Discuss the extent to which PREPA added the 18, 23 MW peaking resources to its ESM scenario because of the existence of proposals to provide new peaking resources to PREPA.**

The following responses were provided by Alfonso Baretty Huertas, Acting Head Planning and Research Division, Puerto Rico Electric Power Authority (PREPA). Alfonso Baretty Huertas certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-04 a) The requested information is not available at this moment. PREPA will provide the information as soon as it becomes available.

PREB-PREPA-01-04 b) The requested information is not available at this moment. PREPA will provide the information as soon as it becomes available.

PREB-PREPA-01-04 c) The requested information is not available at this moment. PREPA will provide the information as soon as it becomes available.

**PREB-PREPA-01-05** **Refer to IRP Main Report, Page 10-2, 10-7. PREPA notes its consideration of fuel infrastructure and permitting activities in Yabucoa and Mayagüez associated with the ESM plan as providing "a further hedge again uncertainties".**

**a) Provide any quantitative assessment of the value of such a hedging approach.**

**b) Did PREPA consider other "hedging" approaches to uncertainty in its ESM plan involving increases in consideration of renewable or storage resources? If so, please provide all documents used in such consideration. If not, please explain why not.**

The following response was provided by Marcelo Saenz, Engagement Manager. Marcelo Saenz certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-05 a) To be provided; requires additional analysis using Aurora.

PREB-PREPA-01-05 b) To be provided; requires additional analysis using Aurora.

**PREB-PREPA-01-06** **The questions below are related to transmission projects not tied to the Minigrids approach.**

**a) Refer to the Responses to Appendix B of the Energy Bureau's March 14 Order, as filed on June 14, 2019. Provide the list implied by PREPA's response to Item 49.**

**b) Reconcile this list of transmission projects with the information provided in Exhibit 2-97 and Exhibit 2-98 of Appendix 1.**

**c) Provide a narrative explanation of how hardening of these transmission assets could affect the definition of minigrid regions, and the related estimation of time-to-restore or time-to-repair for the set of lines identified in Exhibit 2-1 of Appendix 1.**

**d) Are there any specific transmission hardening projects associated with transmission assets that connect one minigrid region to another minigrid region? If so, provide a list of those projects, a description of the project, the project costs, and the minigrid regions which are connected by the projects.**

The following responses were provided by Yan Du, Staff Consultant, Siemens, and Brenda Pérez Román, Acting Manager, PREPA. Yan Du and Brenda Pérez Román certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-06 a) refer to: Confidential-PREPA ROI_1_6 Attach 1.docx for the project list. In this attachment there are hardening projects that are link with the MiniGrid design and projects to be carried out independently of this design and are largely needed to comply with new codes and standards and /or replacing of aging infrastructure.

PREB-PREPA-01-06 b) see a) above

PREB-PREPA-01-06 d) Yes there are "interconnection of Minigrids". Refer to Confidential-PREPA ROI_1_6 Attach 2.xlsx for the project list. These projects have the purpose of minimize the time that the MiniGrid is operating in isolation.

The following responses were provided by Yan Du, Staff Consultant, Siemens. Yan Du certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-06 c) The project in reference were taken into consideration when assessing the likely borders of the MiniGrids and its internal design (i.e. no need to reinforce if there is a hardened project already). There are also hardening projects that that could improve the reliability and make it possible for faster restoration and reconnection of the MiniGrids, however the geography is still a factor. Potentially for example the Minigrid of Mayaguez could be consolidated, Carolina with San Juan – Bayamon or Caguas with Carolina.

**PREB-PREPA-01-07 The questions below are related to the operational definition of "Strategies" as it pertains to local reserve constraints employed in scenario analyses under "minigrid" event periods (e.g., major storm outages separate the grid).**

**a) Refer to Page 17 of PREPA Ex. 6.0, Direct Testimony of Dr. Bacalao and Page 5-2 of the IRP Main Report. In the aforementioned references, it is indicated that Strategy 2 uses a local resource constraint ("e.g., 80%"). Is the constraint exactly 80% in all Scenarios under Strategy 2?**

**b) Is the constraint exactly 50% in all Strategy 3 runs?**

**c) Explain exactly how the local resource constraint is used as a parameter in Aurora's LTCE runs. Does the LTCE run always require 80% of the local load to be served by local resources?**

**d) If so, what specific local load level is used, and how are solar and battery resource attributes counted as a local resource?**

**e) Is there any explicit assessment of load level and duration during the minigrid event? E.g., are critical loads served for 100% of the time, and priority and balance loads served for lower percentages of the time? Please discuss the extent to which the assessment incorporates potentially realistic variations in connected load during a minigrid event situation.**

**f) Provide for base loadings of S4S2, S3S2, S1S2 and the ESM scenario a summary table for each showing, for each minigrid region, for each year through 2038, the available capacity resulting from the scenario, the local peak load used, and the effective local reserve requirement in place for the scenario in each year.**

Responses were provided by Marcelo Saenz, Engagement Manager, Yan Du, Staff Consultant and Nelson Bacalao Senior Manager, Siemens. Nelson Bacalao, Marcelo Saenz and Yan Du certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-07 a) Yes, the constraint is exactly 80% in all areas. In addition, there is an island-wide reserve constraint of 30%.

PREB-PREPA-01-07 b) Yes, the constraint is exactly 50% in all areas. In addition, there is an island-wide reserve constraint of 30%.

PREB-PREPA-01-07 c) The constraint is a reserve requirement that means that the installed capacity in each area plus the demand response available must be equal at least to 80% of the area's peak load; in other words, the reserve margin is at minimum – 20%. Note that this does not means that the local load is served by local resources, but the entire load is served by the economic resources only limited by transmission constraints (which are minimal for the interconnected system considering the current load levels and location of new resources).

PREB-PREPA-01-07 d) Solar resources are not consider contributing to the reserves as a) the system has a night peak and b) during daytime there are ample reserves in the system as storage is charging and the thermal generation is at its minimum. Storage do contribute to the capacity counted towards reserves; 100% of the capacity for 6 hours and 4 hours storage and 50% of the capacity for two hours storage.

PREB-PREPA-01-07 e) In the analysis we ensured the critical loads are served 100% by thermal generations, and the priority and balance loads can be served by thermal and PV generation supported by storage. In our analysis we allowed for rotating load interruptions affecting the priority and the balance of the load. The analysis took into account that in the weeks following a major event there would be a reduction in loads with respect of its peak and this was approximated considering a 25% reduction (e.g. a light load condition).

PREB-PREPA-01-07 f) 1. Please see attachment PREPA ROI_1_7 Attach 1.xlsx for the requested information. Note that this data was extracted from the work papers under the Detailed Metrics tab. Note that in the model Ponce east and Ponce West as well as Bayamon and San Juan were modeled separately, hence reserves for each of these areas are provided.

**PREB-PREPA-01-08** **Refer to Exhibit 2-2 and Exhibit 2-3 of Appendix 1.**

**a) Confirm, or explain otherwise, that levels of deemed critical/priority/balance load used in the Aurora LTCE model runs for Strategy 2 did not consider any starting point reductions from the 2019 night peak load value that might be associated with load unable to be served from local minigrid resources because of distribution system storm damage.**

**b) Provide a discussion of PREPA's understanding of how transmission system and distribution system restoration occurring after a major storm could affect the level of load available to receive energy from the grid.**

**c) Does PREPA's minigrid construct as analyzed in this IRP take into consideration any form of coordination of distribution system recovery with transmission system recovery, effecting which minigrid areas (i) might be able to rely more on restored transmission interconnections to other minigrid areas, or (ii) might experience reduced loading demand because of distribution system damage?**

**d) Confirm, or explain otherwise, that the Aurora LTCE model runs assumed that for one full month, each minigrid region only had access to resources within that minigrid region.**

The following responses were provided by Yan Du, Staff Consultant, Siemens. Yan Du certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-08 a): The LTCE runs to determine the optimal capacity additions were done considering the requirement to supply the entire load; i.e. it considers integrated operation.

PREB-PREPA-01-08 b) There major restorations stages were considered right after or a few hours after the event when only underground facilities were assumed available and largely connected to the critical loads. 2nd, Approximately 1 week after the event when hardened overhead facilities are considered available and supply critical and priority loads and 3rd more than 1 week when longer overhead lines are back in service and the balance of the loads were progressively reconnected. As mentioned in response PREB-PREPA-01-07 e); an overall 25% reduction of the load was assumed to be in place in the weeks following a major event.

PREB-PREPA-01-08 c) The design of the transmission and distribution system were coordinated as hardening of just one will not result in the desired affects to provide reliable power to the customers. This also implies that during reconnection / service restoration transmission and distribution would have to be coordinated. The general concept is to give priority during restoration to those transmission substations that serve a hardened distribution system that would available to take load once the power is available at the MV level. It should be mentioned that while the analysis considered which feeders supply critical and priority loads, conservatively we considered that if a feeders had a critical load connected or a priority that was to be taken, then the entire loads on the feeder would be reconnected.

PREB-PREPA-01-08 d) For the calculation of the Energy Not Served, it is just post processing of the LTCE results using resources in that Minigrid only to calculate the Energy Not Served based on the load in that Minigrid. The Aurora LTCE runs are based on the integrated system model. A full month on unavailability was assumed to produce the estimation. However, it must be stressed that this value ("deemed energy not served") has relative value (i.e. to compare alternatives') rather than absolute value.

**PREB-PREPA-01-09** **Provide the current version, at least in summary form, of PREPA's restoration plan in the event of a major storm. Include specifics on estimated time-to-repair for major infrastructure categories (e.g., transmission, sub-transmission, distribution, generation) and by location in Puerto Rico.**

The following response was provided by Gary F. Soto Fernández, Head of Electric System Operations Division, PREPA. Gary F. Soto Fernández certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** The System Operations Division has a contractor working on various emergency operating protocols, including System Restoration Procedure. This is expected to be completed by next year hurricane season.

**PREB-PREPA-01-10** **Refer to Section 2.15.4 and Exhibit 2-100 of Appendix 1.**

a) **For the example in the text, Carolina minigrid, the first week average VoLL assumed is computed to be roughly \$15,835/MWh [\$348 million divided by 21,977 MWh]. Reconcile this value with the information provided in Exhibit 7-22 "PREPA VOLL Estimates" of the IRP Main Report.**

The following response was provided by Yan Du, Staff Consultant, Siemens. Yan Du certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** We took into consideration of the estimates from the "PREPA VoLL Estimates" in the main report but adjust them to consider that the loss of load would occur on an extended and preannounced event and reflect the separation the load into Critical/Priority and balance, hence assumed \$32,000/MWh for critical load, \$10,000/MWh for Priority load and \$2,000/MWh for balance load for VoLL study in the Appendix 1.

**PREB-PREPA-01-11** **Refer to Page 10-3 of the IRP Main Report. The ESM scenario assumes zero solar PV additions in 2019. Confirm, or explain otherwise, that it is PREPA's understanding or explicit modeling assumption that zero additional solar PV installations will occur in Puerto Rico in 2019. If confirmed, reconcile that understanding or modeling assumptions with any general understandings that some solar PV installations are occurring in the Puerto Rico in 2019.**

The following response was provided by Miguel F. Irizarry Silvestrini, Acting Superintendent, PREPA. Miguel F. Irizarry Silvestrini certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** As of July 31, 2019, no new utility scale solar PV facilities are under construction. It has been our experience that the construction and testing of these facilities usually takes over a year to complete. It is thus reasonable to assume that no new utility scale PV facilities will begin operation in 2019. However, smaller scale solar PV facilities, specifically distributed generation (DG) facilities for self-consumption and/or participation in PREPA's Net Metering Program are continually interconnected to the grid. Providing the total capacity of these facilities is challenging as many are not required to submit a pre-application to PREPA as per current regulations; PREPA receives knowledge of their existence only when the customer notifies the utility of its interconnection.

**PREB-PREPA-01-12** **Refer to Exhibit 10-1 of the IRP Main Report. Confirm, or explain otherwise, that the solar PV additions listed said Exhibit are MW AC, and not MW DC.**

The following response was provided by Marcelo Saenz, Engagement Manager, Siemens. Marcelo Saenz certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:**The solar PV additions are in MW AC units.

**PREB-PREPA-01-13** **Refer to Section 10.1.2 of the IRP Main Report. Confirm, or explain otherwise, that the referenced 680 MW of BESS storage capacity is 4-hour duration.**

The following response was provided by Marcelo Saenz, Engagement Manager, Siemens. Marcelo Saenz certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** Confirmed. The 680 MW is 4-hour duration. The planned BESS additions are split between 200 MW with 2-hour storage capacity, 680 MW with 4-hour storage capacity and 400 MW with 6-hour storage capacity.

**PREB-PREPA-01-14** **Refer to Page 10-3 to 10-4 of the IRP Main Report, regarding the San Juan 5&6 Conversion.**

a) **What will be the marginal cost of operation of these units once converted?**

b) **Are these units expected to operate in a base-load mode?**

The following responses were provided by Marcelo Saenz, Engagement Manager, Siemens. Marcelo Saenz certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-14 a) The marginal cost of operation for the Converted units will be in the \$90-\$100/MWh depending on the capacity factor in 2019-2020. This number includes fuel, variable, emissions and fixed costs. Fixed costs include the capacity payments for the conversion through 2025. Starting in 2025, the fixed costs comprise the regasification costs assigned to the San Juan units, once the LNG terminal at San Juan is developed.

PREB-PREPA-01-14 b) No. The San Juan units are forecast to serve intermediate to peak loads. Forecast capacity factors are in the range of 33% to 55%, on average during the study period and depending on the scenario.

**PREB-PREPA-01-15** **Refer to Page 10-7 of the IRP Main Report, regarding preliminary permitting and engineering costs.**

a) **What are the estimated costs for preliminary permitting and engineering for each of the Yabucoa and Mayaguez Ship-Based LNG Terminal and 302 MW F-class CCGT? Include all component-level estimates used to determine a total.**

The following response was provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-15 a) The estimated costs for the ship-based LNG terminals referenced on Page 10-7 for Yabucoa and Mayaguez were developed on the basis of two sources: (1) the July 2017 study conducted by The Oxford Institute for Energy Studies entitled "The Outlook for Floating Storage and Regasification Units (FSRUs)" (refer to file PREPA ROI_1_15 Attach 1.pdf), and (2) the June 2015 study prepared by Poten & Partners entitled "Interest in Floating Regas Units Grows in Asia" (refer to file PREPA ROI 1_15 Attach 2.pdf). In both studies, the cost of a converted LNG tanker was considered rather than a new build. In the Oxford study, the estimated cost to purchase and convert a used tanker to an FSRU is approximately $100-120 million (converted from £80-100 million). In the Poten & Partners study, the estimated cost to convert a full-size LNG tanker to an FSRU is $80 million. On the basis of these two studies and taking into account market comparables (see attachment "Regasification Market Comparables"), Siemens estimated that the capital expenditure for ship-based LNG delivery to Yabucoa and Mayagüez is $185 million. There are no further estimated costs for preliminary permitting and engineering costs or component-level estimates beyond these two studies and the market comparables.

**PREB-PREPA-01-16** **Refer to Section 10.2 of the IRP Main Report.**

**a) In the second paragraph under Section 10.2.1, what is meant by the phrase "before the infrastructure can be restored..."?**

**b) In particular, explain if this is in reference to (i) generation, (ii) transmission, (iii) sub-transmission, and/or (iv) distribution assets. Be specific.**

**c) In summary form, describe the extent of outage associated with each of the four classes of infrastructure noted above after Hurricanes Irma and Maria.**

**d) In particular, confirm, or explain otherwise, that there was not any extended unavailability of major generation resources after those Hurricanes as a result of the Hurricanes.**

The following responses were provided by Nelson J Bacalao, Senior Manager Consulting, Siemens. Nelson J Bacalao certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-16 a) The infrastructure in reference is the transmission and distribution infrastructure.

PREB-PREPA-01-16 b) See response to a) above.

The following responses were provided by Gary Soto Fernández, Head of Electric System Operations Division, PREPA, and Humberto Campán Colón, Transmission and Distribution Administrator, PREPA. Gary Soto Fernández and Humberto Campán Colón certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-16 c) Included, the Daily Availability Generation Reports for our generation fleet:

a. Report for September 5, 2017 to present the availability before Hurricane Irma – refer to file Confidential-PREPA ROI_1_16 Attach 1.pdf.

b. Report for September 15, 2017 to present the availability between Hurricane Irma and Maria – refer to file Confidential-REPA ROI_1_16 Attach 2.pdf.

c. Report for October 18, 2017 to present the availability after Hurricane Maria. This report took time to prepare because of communications difficulties, and limited personnel resources were used to organize transmission assessments – refer to file Confidential-PREPA ROI_1_16 Attach 3.pdf..

Also included, the Transmission Reestablishment Report for October 23, 2017. This report presents the finding during the first assessments on the transmission lines – refer to file Confidential-PREPA ROI_1_16 Attach 4.xlsx.

Refer to files Confidential-PREPA ROI_1_16 Attach 5.xlsx for information dated November 16, 2017, and Confidential-PREPA ROI_1_16 Attach 6.xlsx for information dated November 20, 2017 on transmission, subtransmission and distribution system.

The following responses were provided by Gary F. Soto Fernández, Head of Electric System Operations Division. Gary F. Soto Fernández certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-16 d) The major generation resources were not affected that much as a result of the hurricanes. The only reason of why the major generation units were offline or curtailed after the hurricanes was due to the fact that PREPA's transmission lines were severely affected by the hurricanes and needed repairs.

**PREB-PREPA-01-17 Refer to Appendix 1, regarding the Transmission and Distribution minigrid use of GIS.**

a) **Provide all workpapers, source documents, and evidence of industry acceptance associated with design choice of GIS as a primary and extensive means to harden transmission and distribution substations in Puerto Rico.**

b) **Distinguishing between space-constrained and non-space constrained transmission, subtransmission, and distribution substations in Puerto Rico when considering minigrid and hardening designs, provide an explanation of whether, or why, consideration of GIS technology was not limited to space-constrained substations.**

The following responses were provided by Yan Du, Staff Consultant, Siemens, and Brenda Pérez Román, Senior Engineer, PREPA. Yan Du and Brenda Pérez Román certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-17 a) GIS was the standard approach together with underground for hurricane hardening in PREPA transmission design in particular in areas like San Juan and Bayamon. GIS within a building minimizes the impact of potential impacts of debris. Other forms of hardening of substations could be considered during the implementation phase. This paper called Gas Insulated Substations (GIS) for Enhanced Resiliency discusses benefits considering the use of gas insulated switchgear in the design and construction of electrical substations to harden against infrastructure damage due to natural and human-caused physical threats to substations (refer to PREPA ROI_1_17 Attach 1.pdf).

The following responses were provided by Yan Du, Staff Consultant, Siemens. Yan Du certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB_PREPA-01-17 b) See above, hurricane hardening was the main consideration in this case.

**PREB-PREPA-01-18 The questions below are related to the Load Forecast.**

a) **Refer to Exhibit 3-5 of the IRP Main Report. Identify the specific source for the GNP values used in the econometric model to generate the PREPA's load forecast. Include the base year used to convert nominal values to real values.**

b) **Provide all the inputs and outputs in a spreadsheet for the econometric model used to produce the 10-year base load forecast for the IRP. Also, include the coefficients for each of the 15 variables that comprise the linear regression model used to develop the gross energy consumption forecast.**

c) **Refer to Exhibit 3-18 of the IRP Main Report, Column "New Customer Owned Distributed Generation". Provide all workpapers, source documents, and assumptions used to forecast customer owned DG adoption over the 10-year IRP planning horizon. Include assumptions regarding the DG technologies and capacity additions by year and performance characteristics (capacity factor etc.).**

d) **Refer to Exhibit 3-18 of the IRP Main Report, Column "New CHP". Provide all workpapers, source documents, and assumptions used to forecast customer owned new CHP over the 10-year IRP planning horizon. Include assumptions regarding the CHP technologies, fuels, and capacity additions by year and performance characteristics (capacity factor etc.).**

e) **Provide all workpapers, source documents, and assumptions used to forecast the impact on system peak demand from energy efficiency and consumer owned generation (DG and CHP) by year over the 10-year IRP planning horizon.**

f) **Refer to Page 3-26 of the IRP Main Report. Provide a detailed rationale for selecting the 85 th and 25 th percentiles of the stochastic distribution of gross sales to represent the High and Low load growth scenarios used for IRP sensitivity analyses.**

g) **Describe to what extent electric vehicles were factored into the load forecast. If included, provide the number of EVs, daily charging profiles, and overall contribution to the system's energy and peak demand requirements.**

The following responses were provided by Marcelo Saenz, Engagement Manager, Siemens. Marcelo Saenz certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-18 a) The historical and forecast GNP values were provided by FOMB and McKinsey.

PREB-PREPA-01-18 b) Please refer to file PREPA ROI_1_18 Attach 1.xlsx.

PREB-PREPA-01-18 e) Energy Efficiency has an impact of 86 MW reduction in load in 2020 rising to 814 MW load reduction by 2038. Solar Distributed Energy Resources do not have an impact on peak demand with Puerto Rico peaking at night time. Consumer CHP has a net impact on peak demand of around 78 MW. CHP resources were modeled as a resource in Aurora, impacting generation from other resources to meet load.

Please refer to file PREPA ROI_1_18 Attach 2.xlsx. See "Yearly Summary" tab.

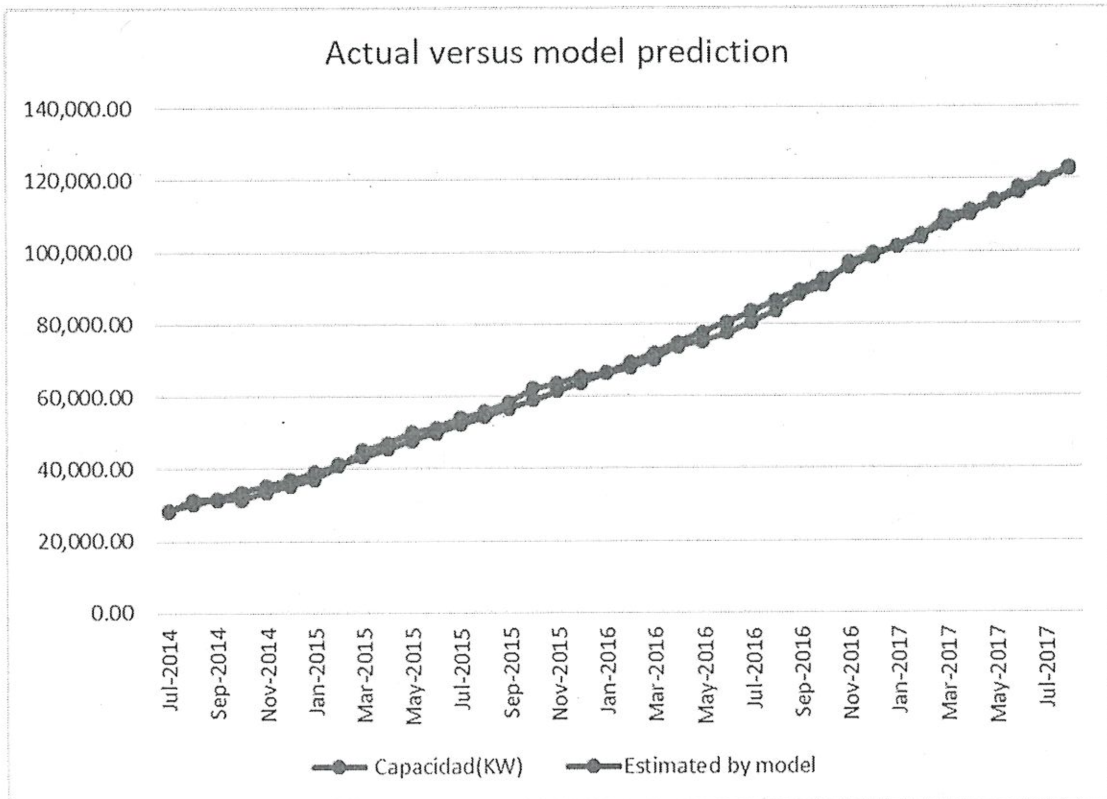
PREB-PREPA-01-18 f) As described on section 3.1.11 of the IRP report, the 85th and 25th percentiles do not represent extreme cases either but a reasonable high and low forecast for planning purposes. To describe the factors that could give rise to the extreme high and low forecasts, Siemens developed very optimistic and very pessimistic scenarios for the macroeconomic parameters driving the forecast: GNP and population. The very optimistic case 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 the FOMB 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 GNP forecast growth rate. Consistent with this economic outlook, there is initially a population drop following the U.S. 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 U.S. Census forecast. The very pessimistic case, 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. In the high case Scenario, gross energy sales increase at 1.34% per-year, with gross 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.

PREB-PREPA-01-18 g) Electric Vehicle (EV) demand was not factored in the load forecast. However, Siemens developed a high-level estimate to assess the potential impact of EV on peak demand. Siemens estimated potential levels of adoption based on total light duty vehicles registered in Puerto Rico and different paths of forecast penetration nationwide and for selected states in the U.S. Siemens include the case of Hawaii, California and West Virginia, and nationwide. As a result, the analysis shows that the potential impact on peak demand is in the order of 20 to 57 MW by 2038. Please refer to the file PREPA ROI_1_18 Attach 3.xlsx.

The following responses were provided by Nelson Bacalao, Senior Manager Consulting. Nelson Bacalao certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-18 c) On the workpapers of Appendix 4 we provided most the requested information and it is attached to the ROA as PREPA_ROI_1_18 Attach. 4.xlsx. In this file we provided the long-term forecast produced by PREPA for Distribution DG as well as the initial forecast of Transmission level DG and CHP. This file also included the the assumptions on Capacity Factors.

The distribution level DG was forecasted by PREPA by the formulation of a model based on the Energy Information Administration (EIA) Annual Energy Outlook (AEO) for Residential Sector Equipment Stock and Efficiency, and Distributed Generation-Solar Photovoltaic Capacity. To develop this model, the Annual Energy Outlook data was first separated in monthly values, using factors determined with the Short-Term Energy Outlook from EIA for 2018 and 2019. PREPA's historical distribution level DG were then used to formulate the forecasting model correlating these distribution level DG with the monthly AEO for small scale renewable generation as the exogenous variable. The model showed good correlation with historical data and was used to create a forecast for distribution level DG generation post June 2018 using the EIA forecast for the exogenous variable growth. The good correlation is shown in the figure below.




To estimate the Distribution DG associated energy, we used a uniform capacity factor of 20% for the projection period. This capacity factor was derived from ENREL's 2018 ATB outlook for residential PV that showed an average capacity factor of 16.3% across various locations and based on Wdc. To convert Wdc to Wac (as forecasted), two factors need to be considered the effect in temperature on the panels reducing its output and the oversizing of the panels with respect of the inverter (under-sizing of the inverter). The DC to AC factor can vary widely with the selection of the inverters with respect of the installed panel capacity and location. For our forecast we selected a factor of 11% temperature degradation and 5.7% under-sizing of the inverter resulting in a DC / AC = 1/(1-5.7%-11%) = 1.2. Thus the 16.3% forecasted by NREL is equivalent to 20% when based on the smaller AC capacity.

For the transmission level DG, we used a capacity factor of 22% which is the same used for utility scale resources in the IRP and reflect the fact that these additions are larger size and connected directly to the transmission system. This capacity factor of 22% is viewed as conservative since the historical values for existing PV are slightly higher, in the 23% range and using the average of NREL's ATB projection (not counting the highest 3 values), the average Capacity Factor based on Wdc is 19% or 23% based on Wac (using the conversion above). The capacity factor of the CHP is a function of the economies as it is can be a "dispatchable" resource.

The transmission level DG, as well as the CHP forecast was done in two parts; first we created a short term forecast based on known interconnection projects reaching completion as discussed below and a forecast based on economics as selected by the LTCE.

Transmission level DG projects in different stages of the interconnection process as well as larger Cogen Combined Heat and Power (CHP) projects are shown in the tables below.

Transmission Level DG by Stages (as of May 2018)

| Region | Interconnected | Electric Planes Endorsed | Evaluated | Incomplete information |
|---|---|---|---|---|
| | *MW* | *MW* | *MW* | *MW* |
| ARECIBO | 3.93 | 0.00 | 3.02 | 0.23 |
| BAYAMON | 7.32 | 0.00 | 4.38 | 0.00 |
| CAGUAS | 8.58 | 0.00 | 3.61 | 1.76 |
| CAROLINA | 3.83 | 3.72 | 1.80 | 0.00 |
| MAYAGUEZ | 1.75 | 0.00 | 0.00 | 0.00 |
| PONCE ES | 3.87 | 0.00 | 5.99 | 0.00 |
| PONCE OE | 4.00 | 0.00 | 1.48 | 0.36 |
| S.JUAN | 9.49 | 0.10 | 14.62 | 5.56 |
| **Total** | **42.75** | **3.82** | **34.91** | **7.92** |

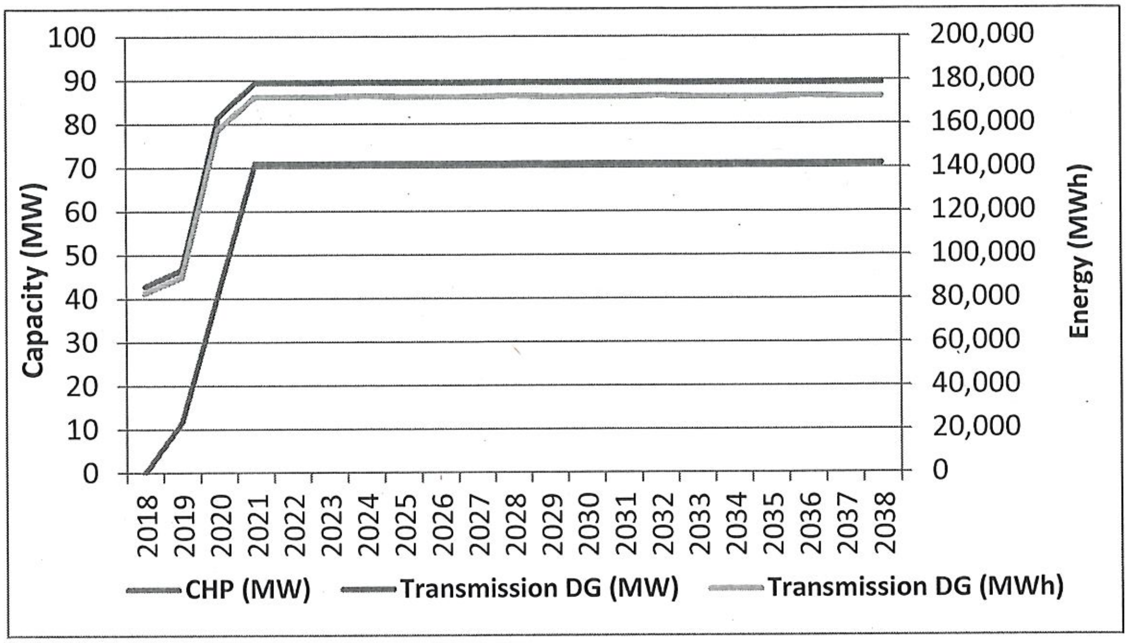
Source: PREPA, Siemens

CHP Projects by Stages (as of May 2018)

| Region | Electric Planes Endorsed | Evaluated | Incomplete information |
|---|---|---|---|
| | *MW* | *MW* | *MW* |
| ARECIBO | 0.00 | 0.00 | 18.00 |
| BAYAMON | 0.00 | 0.00 | 0.00 |
| CAGUAS | 7.87 | 9.60 | 2.50 |
| CAROLINA | 3.12 | 0.00 | 9.00 |
| MAYAGUEZ | 0.67 | 5.92 | 0.00 |
| PONCE ES | 0.00 | 0.00 | 0.00 |
| PONCE OE | 0.00 | 14.21 | 0.00 |
| S.JUAN | 0.00 | 0.00 | 0.00 |
| **Total** | **11.66** | **29.72** | **29.50** |

The projections for transmission Level DG and Cogen (CHP) were made based on the project status information, assuming one-year lag time if the project status is "electric plans endorsed", two-year lag time to operation if the plant is under "evaluation" stage or three-year lag time if the project status is "incomplete information". This is shown in the figure below.

Transmission DG and Cogen Projections




As indicated above, it is expected that the transmission level DG will continue and as these larger scale projects are not embedded with the distribution load but rather connected at 38 kV and above and play a role very similar to utility scale generation. Thus their increased penetration, beyond the one shown above were modeled as taking part in Utility Scale PV forecast.

CHP forecast, beyond those shown above, was produced by the LTCE as a result of offering the CHP option described in appendix 4 and can be observed in the various workpapers for the scenarios results.

PREB-PREPA-01-18 d) please see the answer above.

**PREB-PREPA-01-19** **Refer to the PREPA Fuel Forecast 06032019_Final_with formulas.xlsx workpaper.**

**a) Provide the historical fuel prices for the past ten years for the 14 pricing elements listed in the Delivered Fuel Forecast sheet.**

**b) For each of the 14 pricing elements in the Delivered Fuel Forecast sheet, please provide a breakdown of the delivered fuel price between supply and transportation costs.**

**c) Provide a revised workbook with the #REF error for the delivered natural gas prices for EcoEléctrica resolved.**

The following responses were provided by Edwin Barbosa Viera, Administrator, PREPA. Edwin Barbosa Viera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-19 a) The 14 pricing elements do not have historical pricing where infrastructure does not currently exist. Please refer to the following files:

- PREPA ROI_1_19 Attach 1.xlsx – Aguirre Bunker C
- PREPA ROI_1_19 Attach 2.xlsx – Costa Sur Bunker C
- PREPA ROI_1_19 Attach 3.xlsx – San Juan and Palo Seco Bunker C (note: entries with PS refer to fuel delivered to Palo Seco; entries with SJ refer to fuel delivered to San Juan; entries with SJPS refer to fuel deliveries invoiced together for San Juan and Palo Seco).
- PREPA ROI_1_19 Attach 4.xlsx – Diesel deliveries for all plants
- PREPA ROI_1_19 Attach 5.xlsx – Costa Sur Natural Gas

PREPA has price information readily available for approximately 5 years (provided). The EcoEléctrica Natural Gas and AES Coal delivered prices should be requested from EcoEléctrica and AES respectively. The delivered prices for Aguirre Natural Gas, San Juan Natural Gas, as well as the Bayamón LPG, Mayaguez LNG and Yabucoa LNG deliveries are not available historically.

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-19 b) For Costa Sur, the contract price formula is used. Price is an equal (50%-50%) weighted average of No.6 fuel oil and Henry Hub natural gas, with adders (on top of commodity price) of \$1.125/MMBtu and \$5.95/MMBtu, respectively. These adders are believed to correspond to transport costs. The delivered fuel price to EcoEléctrica when the capacity factor is equal to or greater than 76 percent (>= 76% CF) is the same as Costa Sur through 2021. Beginning in 2022, the delivered fuel price to EcoEléctrica (>= 76% CF) is the same as the forecasted delivered LNG price to other existing or proposed gas-fired plants in Puerto Rico, including San Juan / Palo Seco, Mayagüez, Yabucoa and Aguirre. The delivered fuel price to EcoEléctrica when the capacity factor is less than 76 percent (<76% CF) is based on the energy charge formula through 2021 [ 0.033725*(CPI Index for 2017 / CPI Index for 2003)*0.5 + 0.01957*( Prior Year Henry Hub price / 1.99930695)*0.5 ]. Beginning in 2022, the delivered fuel price to EcoEléctrica (<76% CF) is the same as for San Juan / Palo Seco, Mayagüez, Yabucoa, and Aguirre. For No. 6 0.5% delivered to Costa Sur, the transport adder is $1.2902/MMBtu while for San Juan it is $0.9469/MMBtu. For natural gas (LNG) delivered to San Juan / Palo Seco, Mayagüez, Yabucoa, and Aguirre, the transport adder from the U.S. Gulf Coast is $4.35/MMBtu. The transport adder for Bayamón LPG is $0.25/gallon. The transport adder for AES coal is $10/metric ton. Finally, the transport adder for delivered diesel to San Juan (and Aguirre) is $1.2085/MMBtu. The Costa Sur fuel supply agreement is attached for reference.

PREB-PREPA-01-19 c) Please find attached the revised workbook with the resolved error for the delivered natural gas prices for EcoEléctrica (PREPA ROI_1_19 Attach 6.xlsx).

**PREB-PREPA-01-20** **Refer to Page 7-1 of the IRP Main Report. Indicate if PREPA has analyzed the cost delivered fuel prices to Puerto Rico for natural gas compared to diesel and residue fuel since 2009. If so, please provide a copy of the analysis. If not, please explain why not.**

The following response was provided by Peter Hubbard, Manager, Siemens, and Edwin Barbosa Viera, Administrator, PREPA. Peter Hubbard and Edwin Barbosa Viera certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-20 Siemens did not analyze the cost of delivered natural gas to Puerto Rico compared to the cost of delivered diesel and residual fuel since 2009 for this analysis. The primary reason is that the IRP document is a forward-looking document rather than a retrospective analysis. However, Siemens did analyze the historical price relationship between WTI crude oil and U.S. Gulf Coast Ultra-Low Sulfur No. 2 Diesel as well as the historical price relationship between WTI crude oil and NY Spot No. 6 0.5% (both fuel price histories are from January 2015 to March 2018, i.e., the period after the major price decline in WTI crude oil in late 2014). The analysis was conducted in order to develop regression analysis formulas that would inform future diesel and residual fuel prices as compared to natural gas prices. These regression analyses are included in the 2018 IRP Fuel Forecast spreadsheet. When comparing the base forecasts for Henry Hub natural gas, NY Spot No. 6 0.5%, and U.S. Gulf Coast diesel for the forecast period from 2018 to 2040, we find that Henry Hub natural gas averages $3.49/MMBtu (2017$) while NY Spot No. 6 0.5% (i.e., residual fuel) averages $10.49/MMBtu (2017$ using 152,400 Btu/gallon) and U.S. Gulf Coast diesel averages $15.05/MMBtu (2017$ using 139,600 Btu/gallon). Accordingly, Henry Hub natural gas is 33% and 23% of the price of these two fuels, respectively, in our base forecast.

PREPA compares de cost of LNG delivered to Costa Sur compared to equivalent residual fuel (No. 6); see file PREPA ROI_1_20 Attach 1.xlsx.

**PREB-PREPA-01-21** **Refer to Page 7-2 of the IRP Main Report, regarding natural gas requirements for Puerto Rico. Provide the supporting calculations and assumptions for Siemens estimate of Puerto Rico's LNG demand of 6.5 million tons per annum (MMtpa).**

The following response was provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** The 6.5 MMtpa figure is equivalent to approximately 855 MMcf/d, using the conversion factor of 48,028 MMtpa per MMcf/d. It is important to note that this figure was a preliminary figure that was calculated well in advance of the long-term capacity expansion planning in order to establish a theoretical maximum demand for natural gas. In order to calculate this figure, all existing units (whether natural gas-fired or otherwise, with the exception of hydro) were assumed to take natural gas at existing capacities and heat rates and at a 75% capacity factor. The list of existing units, capacities, and heat rates can be found in Exhibit 4-5 of the IRP Main Document. Although no scenario selected the full list of natural-gas options and conversions (including San Juan, Mayagüez, Yabucoa, EcoEléctrica, and Aguirre), the maximum daily gas demand for these five options would be 667 MMcf/d or 5.1 MMtpa. Again, please note that in none of the scenarios does maximum daily gas demand ever reach 667 MMcf/d.

**PREB-PREPA-01-22** **Refer to Page 7-2 of the IRP Main Report, regarding contracted capacity for liquified natural gas.**

**a) Indicate if PREPA has analyzed and/or assessed LNG contracts for any of its proposed plants. If so, please provide a summary of current contract negotiations and proposed terms.**

**b) Indicate typical contract length required for firm LNG capacity.**

The following responses were provided by Jaime A. Umpierre Montalvo, P.E., Head of Engineering and Technical Services Division, Project Management Office, Executive Directorate, Puerto Rico Electric Power Authority. Mr. Umpierre Montalvo certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-22 a) PREPA is not pursuing or negotiating any new LNG supply contracts for any of its proposed plants at this time. PREPA does have ongoing discussions with the supplier of natural gas for the Costa Sur facility relating to the supply of natural gas, supported by LNG, to the Costa Sur and EcoEléctrica facilities, which have reached the level of a non-binding term sheet and which PREPA expects to discuss with the PREB in the near future. PREPA has also developed a draft Master Fuel Plan that assesses, among other things, LNG supply options and logistics, which it intends to finalize in the coming months.

PREB-PREPA-01-22 b) While the industry-standard LNG supply contract lengths traditionally exceeded 15 years, shorter contracts (*e.g.*, 5-15 years) have become more prevalent in recent years as different types of sellers (*e.g.*, traders) and supply options have come to market.

**PREB-PREPA-01-23** **Refer to Page 7-2 of the IRP Main Report, regarding Jones Act compliant vessels.**

a) **Indicate if PREPA has analyzed the inventory of Jones Act compliant LNG carrier vessels. If so, please provide a copy of the analysis. If not, please explain why not.**

b) **Indicate if PREPA has estimated the LNG carrier vessel requirements to meet its estimated 6.5 MMtpa. If so, please provide a copy of the analysis. If not, please explain why not.**

c) **Indicate if PREPA has estimated the frequency of LNG shipments needed to meet its estimated 6.5 MMtpa requirement. If so, please provide a copy of the analysis. If not, please explain why not.**

The following response was provided by James Bowe, Partner, King & Spalding, and Petter Hubbard, Manager, Siemens. James Bowe and Peter Hubbard certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-23 a) The Jones Act requires that marine trade between U.S. ports (including ports in U.S. territories like Puerto Rico) be conducted exclusively by means of vessels that are U.S. built, U.S. owned, U.S. flagged and U.S. crewed. (Vessels meeting these requirements are known as "coastwise qualified" or "Jones Act compliant"). The Jones Act thus requires that waterborne trade in LNG between LNG sources in the U.S. (such as LNG export terminals located in Louisiana, Texas, Maryland and Georgia) and markets elsewhere in the U.S. be limited to coastwise qualified, or Jones Act compliant, LNG carrier vessels.

PREPA and its advisors have reviewed publicly-available information concerning the availability of oceangoing LNG carrier vessels that comply with the requirements of the Jones Act. That information includes, among others, a report by the Congressional Research Service, "Shipping Under the Jones Act: Legislative and Regulatory Background" (May 17, 2019) (the "CRS Report"), the U.S. Department of Energy's Final Report, "Energy Resilience Solutions for the Puerto Rico Grid (June 2018) (the "DOE Report") and a United States Government Accountability Office Report to Congressional

Committees, "Maritime Transportation – Implications of Using U.S. Liquified-Natural-Gas Carriers for Exports" (December 2015) (the "GAO Report"). Refer to files PREPA ROI_1_23 Attach 1.pdf, PREPA ROI_1-23 Attach 2.pdf and PREPA ROI_1_23 Attach 3.pdf for copies of each of these reports. As indicated in the CRS Report (at Summary and p. 14), the DOE Report (at pp. 25-26) and the GAO Report (at p. 16), there are currently no Jones Act-compliant LNG carrier vessels (i.e., oceangoing vessels capable of transporting LNG in bulk) available. Absent such vessels, or a waiver of the Jones Act permitting deliveries of LNG to Puerto Rico in vessels that are not Jones Act compliant, LNG delivered to Puerto Rico in bulk will need to be obtained from sources other than the United States.

PREB-PREPA-01-23 b) Siemens did not analyze separately the types of LNG carriers needed to meet the estimated LNG requirements. However, Siemens did produce a March 28, 2017 report ("PREPA Fuel Delivery Option Assessment") that looked at the shipping requirements to deliver LNG ISO and CNG ISO containers to three plants on the island. Refer to file Confidential-PREPA ROI_1_23 Attach 4.pdf.

LNG Deliveries to EcoEléctrica, Costa Sur or a New CCGT at the Costa Sur Site: The EcoEléctrica LNG receiving terminal incorporates a jetty extending offshore Peñuelas, PR into deep water in Punta Guayanilla Bay. That receiving terminal currently receives LNG which is stored onshore and is vaporized to supply natural gas to the EcoEléctrica and Costa Sur generating facilities. The terminal's berthing facilities can accommodate standard-size LNG carrier vessels (which have generally had cargo capacity of approximately 135,000 m3, but can have cargo capacity of as much as 175,000 m3). PREPA anticipates that deliveries of LNG to the LNG receiving terminal currently serving the EcoEléctrica and Costa Sur generating facilities will continue to be accomplished through standard-size LNG carrier vessels, whether to support continued deliveries of LNG to the existing EcoEléctrica and Costa Sur generating facilities or to a new CCGT which under some scenarios could be developed at the location.

LNG Deliveries in San Juan Harbor: As indicated in the IRP Main Report (at p. 7-11), a medium-scale LNG carrier vessel (30,000 m3 – 60,000 m3) is likely to be used to deliver LNG to receiving facilities in San Juan harbor to support natural gas deliveries to the San Juan 5 and 6 CCGTs. Larger scale LNG carriers (which would range in capacity from 85,000 m3 to 170,000 m3 or more) would require substantial dredging to create a channel that could accommodate their deeper draft. Smaller, medium-scale, LNG vessels would have the additional advantage of greater maneuverability, which would reduce potential impacts of LNG deliveries on marine traffic in San Juan harbor. It is likely that the additional quantities of LNG that would be needed to support natural gas deliveries to the Palo Seco generating facility site would also be delivered by medium-scale LNG vessels.

Deliveries of LNG to Yabucoa and Mayagüez: As indicated in the IRP Main Report (at p. 7-12), a number of scenarios contemplate the addition of natural gas-fired generating facilities (or conversion of existing aeroderivative gas turbine units) at the Yabucoa and Mayagüez sites. PREPA has assumed in developing the IRP that a ship-based LNG floating storage and regasification unit ("FSRU") would be deployed at either or both of these locations. These FSRUs are likely to be smaller than the standard-sized FSRUs commonly encountered (which generally have a cargo capacity of approximately 135,000 m3, and are likely to be supplied by medium- to standard-sized LNG carrier vessels.

The following response was provided by Peter Hubbard, Siemens. Petter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-23 c) The figures cited on Page 7-11 are based on an estimated 350 MW gas-fired capacity at San Juan, which would require an expected daily gas volume of 50.4 MMcf/d. If a pipeline to the Palo Seco plant is included, adding an incremental 302 MW of gas-fired capacity at Palo Seco plant, the expected daily gas volume requirement would increase to 93.6 MMcf/d. A mid-scale (Type C - 30,000 m3) LNG carrier would deliver approximately 651.6 MMcf/d of natural gas, using a conversion factor of 21,719 cf per m3 of LNG. To satisfy San Juan's fuel requirements of 50.4 MMcf/d, this would require a shipment every 12.9 days or 29 shipments per year (rounding up). To satisfy San Juan and Palo Seco's fuel requirements of 93.6 MMcf/d, this would require a shipment every 7.0 days or 53 shipments per year (rounding up).

**PREB-PREPA-01-24** **Refer to Page 7-2 of the IRP Main Report, regarding LNG ISO containers.**

**a) Indicate if PREPA has estimated the LNG ISO container requirements to meet its estimated 6.5 MMtpa. If so, please provide a copy of the analysis. If not, please explain why not.**

**b) Indicate if PREPA has analyzed the inventory of LNG ISO containers that would be required to meet its estimated 6.5 MMtpa requirement. If so, please provide a copy of the analysis. If not, please explain why not.**

**c) Indicate if PREPA has estimated the frequency of LNG ISO containers needed to meet its estimated 6.5 MMtpa requirement. If so, please provide a copy of the analysis. If not, please explain why not.**

**d) Indicate if PREPA has estimated the environmental impact of the need for LNG ISO containers required to meet its estimated 6.5 MMtpa. If so, please provide a copy of the analysis. If not, please explain why not.**

**e) Indicate if PREPA has estimated the shipping traffic impact of the need for LNG ISO containers required to**

**meet its estimated 6.5 MMtpa. If so, please provide a copy of the analysis. If not, please explain why not.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-24 a) Siemens prepared for PREPA a report entitled, "PREPA Fuel Delivery Option Assessment" dated March 28, 2017 that examined the practicality and competitiveness of delivering sufficient volumes of containerized LNG or CNG to displace diesel and No. 6 fuel oil as a potential interim or long-term solution. The report did not look at requirements to meet the estimated 6.5 MMtpa maximum demand for natural gas. The assessment included Aguirre in the absence of the AOGP project as well as San Juan and Palo Seco. The maximum gas demand at these three sites was estimated to be 197,466 MMBtu/day (equivalent to 193 MMcf/d or 1.46 MMtpa). The key conclusions from this fuel delivery option assessment included:

- CNG delivery either as a bridge fuel or long-term solution is not practical due to PREPA's expected demand in the three sites.
- LNG delivery in ISO containers to Aguirre absent AOGP is not practical due to the expected gas demand and the amount of container handling required on a daily basis and vessel deliveries required on an annual basis. In addition, dredging will be required at the Aguirre port, which could be a fatal flaw.
- The costs and operational risks for LNG delivery in ISO containers to San Juan are prohibitively high.

Refer to file Confidential-PREPA ROI_1_23 Attach 4.pdf for a copy of the PREPA Fuel Delivery Option Assessment for reference.

PREB-PREPA-01-24 b) The LNG ISO containers required to meet the maximum gas demand of 197,466 MMBtu/day was estimated to be 230 containers/day.

PREB-PREPA-01-24 c) The frequency of LNG ISO containers deliveries was estimated to be 230 containers/day.

PREB-PREPA-01-24 d) The environmental impact of LNG ISO container deliveries to San Juan and Palo Seco was estimated to be moderate in terms of leaks and spills. The environmental impact of LNG ISO container deliveries to Aguirre was found to be high and thus not practical, given that "waterway access to the Aguirre site is an environmentally protected area, which cannot be disturbed. Thus the waterway depth and condition cannot be altered to accommodate larger vessels, so access is limited to vessels with loaded depths of probably less than twenty feet."

PREB-PREPA-01-24 e) The analysis estimated that LNG ISO container delivery to Aguirre, San Juan, and Palo Seco would require 57 trips per year.

**PREB-PREPA-01-25** **Refer to Page 7-2 of the IRP Main Report, regarding the Trinidad and Tobago LNG capacity.**

**a) Indicate if Siemens analyzed current and future LNG export capacity of Trinidad and Tobago. If so, please provide a copy of the analysis. If not, please explain why not.**

**b) Indicate if Siemens analyzed current and future LNG export capacity of Trinidad and Tobago to meet PREPA's estimated 6.5 MMtpa requirements. If so, please provide a copy of the analysis. If not, please explain why not.**

**c) Provide current pricing contracts and durations for LNG that PREPA receives from Trinidad and Tobago.**

**d) Information on shipment, quantity, and delivered price for LNG that PREPA receives from Trinidad and Tobago for each of the last five years.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-25 a) Siemens reviewed information on current LNG export capacity from Trinidad and Tobago, which includes Atlantic LNG Trains 1-4 totaling 15.5 MMtpa (2,054 MMcf/d) of export capacity. Siemens did not review plans for Trinidad and Tobago to develop future export capacity. Of the existing capacity, Shell owns 52.9%, BP owns 39.1%, NGC Trinidad owns 5.9%, and China Investment Corporation owns 2.1%. Siemens did not review contract information for these entities to determine whether spare contracted capacity could exist in the future to meet current or future LNG demand in Puerto Rico.

PREB-PREPA-01-25 b) Siemens did not analyze the current and future LNG export capacity of Trinidad and Tobago to meet PREPA's estimated 6.5 MMtpa requirements. Rather, a U.S. Gulf Coast natural gas commodity price was used (the U.S. benchmark Henry Hub) with the assumption that U.S. Gulf Coast LNG pricing and Trinidad and Tobago LNG pricing would face similar competitive pressures, which would bring pricing into rough alignment. Moreover, by focusing on U.S. Gulf Coast natural gas pricing, Siemens was able to utilize its fundamentals-based model (the Gas Pipeline Competition Model or GPCM®).

The following response was provided by Edwin Barbosa Viera, Administrator, PREPA. Edwin Barbosa Viera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-25 c) PREPA does not have a contract for purchase of LNG from Trinidad and Tobago. EcoEléctrica, as intervener, can provide further information.

PREB-PREPA-01-25 d) PREPA does not have a contract for purchase of LNG from Trinidad and Tobago. EcoEléctrica, as intervener, can provide further information.

**PREB-PREPA-01-26** **Refer to Page 7-2 of the IRP Main Report, regarding the EcoEléctrica natural gas send-out.**

**a) What is the current status of the fourth gasifier?**

**b) Provide a copy of the current Costa Sur natural gas contract.**

**c) Indicate if PREPA would need to expand current pipeline capacity in order to utilize the additional 93 MMcf/d capacity with the fourth gasifier.**

The following response was provided by Gary F. Soto Fernández, Head of Electric System Operations Division, PREPA. Gary F. Soto Fernández certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-26 a) The fourth gasifier is fully operational but it is used as a backup since EcoEléctrica has authorization to have only three gasifiers online. Please contact EcoEléctrica for more details.

PREB-PREPA-01-26 c) With the current setup of online gasifiers, Costa Sur and EcoEléctrica units can be dispatched 100%. Please contact EcoEléctrica for more details.

The following response was provided by Edwin Barbosa Viera, Administrator, PREPA. Edwin Barbosa Viera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-26 b) Refer to files PREPA ROI_1_26 Attach 1.pdf, PREPA ROI_1_26 Attach 2.pdf, PREPA ROI_1_26 Attach 3.pdf, PREPA ROI_1_26 Attach 4.pdf and PREPA ROI_1_26 Attach 5.pdf for the Costa Sur natural gas contract and amendments.

**PREB-PREPA-01-27** **Refer to Page 7-3 of the IRP Main Report, regarding the EcoEléctrica storage tank. Describe the permitting requirements and project timeline associated with the installation of a second LNG storage tank.**

The following response was provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** Siemens and PREPA defer to EcoEléctrica to provide a response to this question.

**PREB-PREPA-01-28** **Refer to Page 7-3 of the IRP Main Report, regarding the EcoEléctrica contracting. Indicate if PREPA has initiated negotiations with EcoEléctrica regarding either (i) expanding gasification capacity or (ii) adding additional LNG storage. If so, please provide a summary of negotiations.**

The following response was provided by Alfonso Baretty Huertas, Acting Head Planning and Research Division, Puerto Rico Electric Power Authority (PREPA). Alfonso Baretty Huertas certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** The requested information is not available at this moment. PREPA will provide the information as soon as it becomes available.

**PREB-PREPA-01-29** **Refer to Page 7-3 of the IRP Main Report, regarding fuel cost reduction goals.**

**a) Provide a qualitative and quantitative summary of actions undertaken by PREPA to achieve its aspirational 20-25% cost reduction by FY2023.**

**b) Provide a qualitative and quantitative summary of current challenges faced by PREPA to achieve its aspirational 20-25% cost reduction by FY2023.**

The following responses were provided by Alfonso Baretty Huertas, Acting Head Planning and Research Division, Puerto Rico Electric Power Authority (PREPA). Alfonso Baretty Huertas certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-29 a) The requested information is not available at this moment. PREPA will provide the information as soon as it becomes available.

PREB-PREPA-01-29 b) The requested information is not available at this moment. PREPA will provide the information as soon as it becomes available.

**PREB-PREPA-01-30** **Refer to Page 7-3 of the IRP Main Report, regarding Power Purchase Agreements.**

**a) Provide a summary PPA terms for EcoEléctrica and AES.**

**b) Indicate if PREPA has the ability to renegotiate either or both power purchase agreements. If so, please provide a summary of current renegotiation discussions.**

The following response was provided by Roberto Rivera Medina, Acting Manager, PREPA. Roberto Rivera Medina certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-30 a) Refer to file PREPA ROI_1_30 Attach 1.docx for the summary of terms for EcoEléctrica and PREPA ROI_1_30 Attach 2.docx for the summary of terms for AES.

The following response was provided by Jaime A. Umpierre Montalvo, P.E., Head of Engineering and Technical Services Division, Project Management Office, Executive Directorate, Puerto Rico Electric Power Authority. Mr. Umpierre Montalvo certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

Response: PREB-PREPA-01-30 b) The current Title III process places PREPA in a stronger position to renegotiate its power purchase and operating agreements (PPOAs) with EcoEléctrica and AES than it would otherwise have. PREPA's current negotiations comprise discussions with EcoEléctrica, at the level of a non-binding term sheet, which PREPA expects to discuss with the PREB in the near future.

**PREB-PREPA-01-31** **Refer to Page 7-3, Exhibit 7-2, of the IRP Main Report, regarding fuel prices.**

**a) Indicate if the prices shown in the Exhibit are delivered prices for Puerto Rico.**

**b) Indicate if PREPA has analyzed delivered fuel prices across fuels for Puerto Rico. If so, please provide a copy of the PREPA's analysis on historical delivered fuel prices.**

The following response was provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-31 a) The prices in Exhibit 7-2 on Page 7-3 of the IRP Main Report are not delivered prices to Puerto Rico. Rather they are Wholesale/Resale Price by Refiners as provided by the U.S. Energy Information Administration (data source: https://www.eia.gov/dnav/pet/PET_PRI_REFOTH_DCU_NUS_M.htm). Siemens did analyze future delivered fuel prices across fuels for Puerto Rico, the analysis for which is captured in the Delivered Fuel Price tab of the 2018 IRP Fuel Forecast workpapers document.

The following response was provided by Edwin Barbosa Viera, Administrator, PREPA. Edwin Barbosa Viera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-31 b) PREPA does not analyze the delivered fuel prices for Bunker C versus Diesel since there is a high discrepancy in price between both fuels.

**PREB-PREPA-01-32** **Refer to Page 7-4 of the IRP Main Report, regarding residual fuel oil.**

**a) Provide current pricing contracts and durations for residual fuel oil that PREPA receives.**

**b) Provide information on shipment, quantity, and delivered price for residual fuel oil that PREPA receives for each of the last five years.**

The following responses were provided by Edwin Barbosa Viera, Administrator, PREPA. Edwin Barbosa Viera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-32 a) Refer to files PREPA ROI_1_32 Attach 1.pdf, PREPA ROI_1_32 Attach 2.pdf, PREPA ROI_1_32 Attach 3.pdf and PREPA ROI_1_32 Attach 4.pdf for the Bunker C purchase agreement and amendments.

PREB-PREPA-01-32 b) Refer to files PREPA ROI_1_32 Attach 5.xlsx, PREPA ROI_1_32 Attach 6.xlsx and PREPA ROI_1_32 Attach 7.xlsx.

**PREB-PREPA-01-33** **Refer to Page 7-4 of the IRP Main Report, regarding diesel fuel oil.**

**a) Provide current pricing contracts and durations for diesel fuel oil that PREPA receives.**

**b) Provide information on shipment, quantity, and delivered price for diesel fuel oil that PREPA receives for each of the last five years.**

The following responses were provided by Edwin Barbosa Viera, Administrator, PREPA. Edwin Barbosa Viera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB_PREPA-01-33 a) Refer to files PREPA ROI_1_33 Attach 1.pdf and PREPA ROI_1_33 Attach 2.pdf for the diesel fuel purchase agreement and amendments.

PREB-PREPA-01-33 b) Refer to file PREPA ROI_1_33 Attach 3.xlsx.

**PREB-PREPA-01-34** **Refer to Page 7-5 of the IRP Main Report, regarding natural gas from Trinidad and Tobago.**

**a) Indicate if PREPA has negotiated a new contract for LNG capacity from Trinidad and Tobago. If so, please provide a summary of the new contract terms and duration. If not, please explain why not.**

**b) Indicate if Trinidad and Tobago have the ability to meet the projected 6.5 MMtpa requirement for new natural gas generation.**

The following response was provided by Edwin Barbosa Viera, Administrator. Edwin Barbosa Viera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-34 a) PREPA does not have a contract for LNG from Trinidad and Tobago; PREPA acquires natural gas in terms of MMBtu for Costa Sur. Please contact EcoEléctrica for further information on this item.

PREB-PREPA-01-34 b) Please contact EcoEléctrica for further information on this item.

**PREB-PREPA-01-35** **Refer to Page 7-5 of the IRP Main Report, regarding the Costa Sur take-or-pay gas contract. Provide a copy of the contract referenced in the text.**

The following response was provided by Edwin Barbosa Viera, Administrator, PREPA. Edwin Barbosa Viera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** Please refer to answer for PRE-PREPA-01-26 b) above.

**PREB-PREPA-01-36** **Refer to Page 7-5 of the IRP Main Report, regarding the EcoEléctrica import terminal.**

**a) Indicate the amount of time it takes to unload an LNG cargo shipment at the import terminal currently.**

**b) Indicate the number of cargo ships deliveries would be required to meet the project send out of 372 MMcf/d.**

The following response was provided by Roberto Rivera Medina, Acting Manager, PREPA. Roberto Rivera Medina certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-36 a) Please refer to Ecoeléctrica for information on this item.

PREB-PREPA-01-36 b) Please refer to Ecoeléctrica for information on this item.

**PREB-PREPA-01-37** **Refer to Page 7-5 of the IRP Main Report, regarding coal.**

**a) Provide current pricing contracts and durations for coal that AES receives.**

**b) Provide information on shipment, quantity, and delivered price for coal that AES receives for each of the last five year**

The following responses were provided by Roberto Rivera Medina, Acting Manager, PREPA. Roberto Rivera Medina certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-37 a) Please refer to attachment PREPA ROI_1_37 Attach 1.docx. For further information regarding the AES coal contracts, please contact AES.

PREB-PREPA-01-37 b) Please contact AES for information regarding this item.

**PREB-PREPA-01-38** **Refer to Page 7-6 of the IRP Main Report, regarding the San Juan Units 5&6.**

**a) Provide a current status update on the conversion of Units 5 and 6.**

**b) Provide a current status update on the micro-fuel handling facility being constructed by New Fortress Energy to supply Units 5 and 6.**

**c) Provide a copy of the natural gas supply agreement between PREPA and New Fortress Energy for Units 5 and 6.**

**d) Describe how PREPA plans to maintain the capacity factor for the two units at 89-93%.**

**e) Provide the historical annual generation and capacity factors for each of the two units for the past ten years.**

**f) Describe the fuel handling capacity of the micro-fuel handling facility being constructed by New Fortress Energy to supply Units 5 and 6.**

**g) Indicate if the micro-fuel handling facility being constructed by New Fortress Energy to supply Units 5 and 6 has the ability to expand. If so, please explain.**

The following responses were provided by Jaime Umpierre Montalvo, Technical Advisor, PREPA. Jaime Umpierre Montalvo certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-38 a) The critical path items required in order to begin the San Juan Units 5 and 6 turbine conversion projects are the EPA and EQB air permits. These involve modifications to the existing PSD Environmental Permit for the Emission Source. The status of these modifications is as follows:

- EPA Conditions to the Existing PSD Permit (Non PSD Applicability): notification received on July 22, 2019.

- EQB Construction (Air) Permit application: filed with the EQB by PREPA on July 26, 2019.

The conversion works in the Unit 5 and 6 turbines are currently scheduled to proceed as follows:

- Unit 6: scheduled outage to begin by September 15, 2019. The outage will extend to the end of October 2019.

- Unit 5: scheduled outage to begin by December 2019. This outage will extend to the end of April 2020. This is a longer outage because of the required modifications to the HRSG for the SCR/CO Cat installations.

  Note: Mitsubishi Power Systems requires four weeks for mobilization and two weeks of pre-outage time on site to commence the turbine conversion works.

All required demolition works within the San Juan Power Plant have been completed. On July 1, 2019, immediately after receiving limited authorization from the local regulator, New Fortress Energy ("NFE") contractors commenced civil and welding works for the required infrastructure inside the San Juan Power Plant. By July 19, 2019, 26% of the required gas piping shop welds had been completed and 18% of total linear feet of gas piping had been installed.

The following response was provided by James Bowe, Partner, King & Spalding, and Petter Hubbard, Manager, Siemens. James Bowe and Peter Hubbard certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-38 b) Construction of the NFE micro-fuel handling facility is ongoing. All surveying and layout work has been completed, as has essentially all required demolition work. Activities currently underway include miscellaneous civil work, piles installation, construction of impoundments and foundations, installation of storm sewers and installation of underground electrical duct banks. As of July 25, 2019 (the date of the most recent project update report furnished by NFE), procurement of the gas metering skid, gas filters, isolation joints, control system components and mechanical piping and materials is in progress, with the relevant purchase orders issued and fabrication of the metering skid and gas filters more than 50% complete. Excavation work for foundations and piping was scheduled to commence during the final week of July, and forming was scheduled to commence during the first week of August. Concrete pouring is scheduled to commence during the second week of August. Pipe support installation is scheduled to commence during the second week of August; piping installation is scheduled to commence at approximately the same time. Electrical work is scheduled to commence during the first week of September; equipment and panels are scheduled to be installed beginning by October 1. The described work is currently scheduled to be substantially complete by the second week of November.

PREB-PREPA-01-38 c) Refer to file PREPA ROI_1_38 Attach 1.pdf.

PREB-PREPA-01-38 f) The micro-fuel handling facility's current design has the operational capability of vaporizing LNG in excess of 25 TBTU per year to supply PREPA Units 5 & 6. The micro-fuel handling facility's current design also has the capacity to load four LNG tankers or ISO containers per hour, giving the facility the operational capacity to support delivery of LNG by truck to industrial and commercial customers and to distributed generation units such as those currently installed at Palo Seco.

PREB-PREPA-01-38 g) The micro-fuel handling facility is capable of expanding its LNG vaporization capacity to approximately twice the capacity of its currently contemplated operations described above.

The following responses were provided by Nelson Bacalao Senior Manager, Siemens, and Dan Yu, Staff Consultant, Siemens. Nelson Bacalao and Dan Yu certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

Response: PREB-PREPA-01-38 d) The 89-93% capacity factor indicated was only used to calculate maximum fuel requirements.

The following responses were provided by Hugal R. Ríos Díaz, Executive Advisor, PREPA. Hugal R. Ríos Díaz certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-38 e) Refer to file PREPA ROI_1_38 Attach 2.pdf

**PREB-PREPA-01-39** **Refer to Page 7-6 and 7-7 of the IRP Main Report, regarding fuel infrastructure options.**

**a) Identify all fuel infrastructure options that would be needed to meet the proposed 6.5 MMtpa LNG requirement identified on Page 7-1 of the IRP Main Report.**

**b) Provide the associated capital costs with supporting documentation and calculations for each of the identified fuel infrastructure options.**

**c) Confirm that the AOGP terminal is only considered in Scenario 5 of the IRP.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-39 a) Siemens identified all fuel infrastructure options that could potentially be implemented to meet the estimated 6.5 MMtpa LNG requirement (which was a preliminary estimate). These options are summarized in Exhibit 7-4 of the IRP Main Document. Not all of these options would necessarily be required to meet the estimated LNG requirement. These options and the associated capital costs and supporting documentation include the following:

- Aguirre Offshore GasPort
    - CAPEX (2018$): $403 million
    - Documentation: CAPEX from 2017 Siemens Aguirre Site Economic Analysis (refer to file Confidential-PREPA ROI_1_39 Attach 1.pfd)
- Ship-based LNG at San Juan with pipeline to Palo Seco
    - CAPEX (2018$): $185 million ship-based LNG + $35 million pipeline to Palo Seco
    - Documentation: The CAPEX estimate has two parts. A mid-scale (Type C - 30,000 m$^3$) LNG carrier is estimated to cost $105 million, per a 2017 Energy Studies Institute (ESI) report (reference file PREPA ROI_1_39 Attach 2.pdf), plus $80 million to add gasification, jetty, and pipe infrastructure (see also PREB-PREPA-01-15 a) response). The pipeline CAPEX estimate is reduced (from $65MM in the 2015 IRP document to $35MM) because the pipeline distance is only 4.2 miles and follows an existing Right-of-Way (ROW). A more reasonable pipeline CAPEX estimate is $8.3 million per mile.
- Land-based LNG at San Juan with pipeline to Palo Seco
    - CAPEX (2018$): $457 million + $35 million pipeline to Palo Seco
    - Documentation: The $457 million figure comes from the 2015 IRP document, inflated to 2018$. The pipeline CAPEX estimate is reduced (from $65MM in the 2015 IRP document to $35MM) because the pipeline distance is only 4.2 miles and follows an existing Right-of-Way (ROW). A more reasonable pipeline CAPEX estimate is $8.3 million per mile.
- Ship-based LNG at Mayagüez (west)
    - CAPEX (2018$): $185 million ship-based LNG + $35 million pipeline to Palo Seco
    - Documentation: A mid-scale (Type C - 30,000 m$^3$) LNG carrier is estimated to cost $105 million, per the 2017 ESI report plus $80 million to add gasification, jetty, and pipe infrastructure.
- Ship-based LNG at Yabucoa (east)

    - CAPEX (2018$): $185 million ship-based LNG + $35 million pipeline to Palo Seco
    - Documentation: A mid-scale (Type C - 30,000 $m^3$) LNG carrier is estimated to cost $105 million, per the 2017 ESI report plus $80 million to add gasification, jetty, and pipe infrastructure.

- LNG or compressed natural gas (CNG) delivery to San Juan and potentially Palo Seco
    - CAPEX (2018$): $540 million
    - Documentation: This figure is based on Exhibit 18 (inflated to 2018$) from the Siemens' PREPA Fuel Delivery Option Assessment study dated March 2017 (reference file Confidential-PREPA ROI_1_23 Attach 4.pdf)

- Additional regasification capacity and new natural gas pipelines, first from EcoEléctrica LNG Import Terminal to Aguirre and then to San Juan
    - CAPEX (2018$): Costa Sur to Aguirre Pipe=$184 million; Aguirre to San Juan Pipe=$238 million
    - Documentation: A 2008 (Gasoducto del Norte aka Via Verde) report provided estimated costs for such a pipeline (not attached; hard copy available via PREPA). The Aguirre-San Juan overland route (not the route along Route 52) was about 52 miles long before adjustment for terrain. A 20-inch pipeline size was assumed for a flow volume of 249 MMcf/d. Costs included route surveying, engineering, project management, inspection, materials, construction and restoration. The cost of this line in mid-2008 U.S. dollars was $206 million, or $238 million in 2018 dollars. This comports well with Siemens' current estimate of a cost of $221 million for this South-North pipeline route, although Siemens estimated that a 16" pipe is sufficient to supply the combined 93.6 MMcf/d demand from San Juan and Palo Seco after conversion to natural gas. Other assumptions used by Siemens include a distance of 49 miles and $4.5 million per mile (2018$). The pipeline nominal length from Costa Sur to Aguirre is 42 miles. Using a cost of $5.1 million per mile (2018$) for 20" pipeline, which would carry 249 MMcf/d or sufficient gas volumes to supply Aguirre, San Juan and Palo Seco, this would cost approximately $214 million. This cost per mile is less than the San Juan to Palo Seco cost because it is not in a highly developed setting. The total cost for a pipeline from EcoEléctrica LNG Import Terminal to Aguirre to San Juan is estimated to be $470 million, including $35 million for a short 4.2 mile pipeline to the Palo Seco plant.

PREB-PREPA-01-39 b) See above response.

PREB-PREPA-01-39 c) Confirmed.

**PREB-PREPA-01-40** **Refer to Page 7-7 of the IRP Main Report, regarding Aguirre fuel conversion capital costs.**

**a) Indicate if Siemens or PREPA has estimated the capital costs for fuel conversion at the Aguirre units. If so, please provide a copy of the estimate. If not, please explain why not.**

**b) Indicate if the natural gas fuel consumption associated with the conversion of the Aguirre units is included in the 6.5 MMtpa estimate for LNG consumption. If so, please provided the estimated annual LNG capacity that would be required for the converted Aguirre units.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-40 a) Siemens estimated the capital costs for fuel conversion at the Aguirre units to natural gas, which can be found in Table 8-1 of the attached April 2017 Aguirre Site Economic Analysis document (refer to file Confidential-PREPA ROI_1_39 Attach 1.pdf). The conversion of the combined cycle units is estimated (in 2015$) to be $46.6 million while conversion of the Aguirre steam units is estimated (in 2015$) to be $87.5 million.

PREB-PREPA-01-40 b) The 6.5 MMtpa estimate for LNG consumption assumed conversion of the Aguirre units to natural gas (as well as all other existing fossil units, as explained in the response to PREB-PREPA-01-21). The existing Aguirre units include 1,420 MW of diesel- and residual fuel oil-fired generation (see Exhibit 4-5 of the Main IRP Document). If converted to natural gas, the expectation is that the maximum capacity of gas-fired generation would be 1,076 MW. The maximum daily volume of natural gas estimated to be required for this converted capacity would equal 155 MMcf/d.

**PREB-PREPA-01-41** **Refer to Page 7-7 of the IRP Main Report, regarding Aguirre fuel conversion fuel costs.**

**a) Explain the basis for using Gulf Coast LNG offtaker pricing for the Aguirre units.**

**b) Confirm that the Gulf Coast LNG pricing assumes the existence of Jones Act compliant LNG vessels. If it does not, explain how the offtaker pricing reflects shipping availability and costs.**

**c) Compare the proposed Gulf Coast pricing formula with the pricing formula from LNG supplied from Trinidad and Tobago.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-41 a) U.S. Gulf Coast LNG is a nearby low-cost source of LNG that could potentially supply Aguirre's fuel requirements. U.S. Gulf Coast LNG was used as the basis for offtaker pricing for the Aguirre units due to the ongoing large-scale development of LNG export facilities on the U.S. Gulf Coast and the expectation that Jones Act compliant LNG vessels could be secured for delivery of LNG to Puerto Rico. In addition, as discussed in the response to PREB-PREPA-01-25 b), a U.S. Gulf Coast natural gas commodity price was used (the U.S. benchmark Henry Hub) with the assumption that U.S. Gulf Coast LNG pricing and Trinidad and Tobago LNG pricing would face similar competitive pressures, which would bring pricing into rough alignment.

PREB-PREPA-01-41 b) The U.S. Gulf Coast pricing assumes that Jones Act compliant LNG vessels could be secured for delivery of LNG to Puerto Rico, whether with or without a pending waiver that was requested by PREPA in December 2018.

PREB-PREPA-01-41 c) The U.S. Gulf Coast pricing assumes Henry Hub commodity cost pricing plus 15% plus $4.35/MMBtu to account for liquefaction, transport, and margin, which is a similar pricing formula to that used by large-scale U.S. Gulf Coast LNG offtakers. According to the U.S. DOE, vessel-borne imports of LNG to Puerto Rico from Trinidad and Tobago in the first five months of 2019 (total of 11 shipments) averaged $8.32/MMBtu landed price (see file PREPA ROI_1_41 Attach 1.xlsx or visit this DOE website: https://www.energy.gov/fe/downloads/lng-monthly-2019). Compare this to the average Henry Hub price in the first five months of 2019 of $2.81/MMBtu (source: https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm), which with the 15% adder and the $4.35/MMBtu adder comes to $7.58/MMBtu or 9% lower than the delivered price of LNG from Trinidad and Tobago.

**PREB-PREPA-01-42** **Refer to Page 7-9 of the IRP Main Report, regarding Ship-based LNG (or CNG) at San Juan.**

**a) Provide the capital and associated operating costs for the 14 configurations considered in the Galway report.**

**b) Identify the permitting requirements and project timeline to install a floating storage and regasification unit off the coast of San Juan.**

The following responses were provided by Peter Hubbard, Manager, Simens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-42 a) The Galway report is attached for reference (see file PREPA ROI_1_42 Attach 1.pdf. However, the Galway report scope of work did not include an assessment of the capital and associated operating costs for the 14 configurations considered. Siemens' scope of work also did not include an assessment of the capital and associated operating costs for the 14 configurations considered in the Galway report. Accordingly, this information is not readily available.

PREB-PREPA-01-42 b) Insofar as permitting requirements, the Galway report identified several U.S. agencies that would be required to provide permits for ship-based LNG or CNG at San Juan, including the Federal Energy Regulatory Commission (FERC), the U.S. Army Corps of Engineers (USACE), the U.S. Coast Guard, the Occupational Safety and Health Administration (OSHA), and possibly other agencies, including local agencies in Puerto Rico. The Galway report estimates that the permitting timeline for any dredging projects associated with these 14 options would require 1.5 to 4 years but would likely be on the lower end of this range.

**PREB-PREPA-01-43** **Refer to Page 7-10 of the IRP Main Report, regarding the FSRU Analysis.**

**a) Indicate if the $105 million cost estimate for the 30,000 m 3 LNG tanker would be the cost estimate for a Jones Act compliant tanker. If not, please provide a cost estimate and supporting documentation for a Jones Act compliant LNG vessel.**

**b) Indicate if PREPA has developed Puerto Rico specific cost-estimate for a FSRU. If so, please provide a copy of the analysis and supporting calculations. If not, please explain why not.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-43 a) The $105 million cost estimate for the purchase of a used 30,000 $m^3$ LNG tanker does not take into consideration Jones Act compliance. This is because an FSRU unit is not directly involved in the transportation of LNG between U.S. ports but rather indirectly. The FSRU is not transporting the LNG; it is receiving and storing the LNG. It is not clear from the language of the Jones Act whether an FSRU would fall under the purview of the Jones Act (though certainly the tanker delivering the LNG to the FSRU would).

A recent Congressional Research Service report (refer to file PREPA ROI_1_23 Attach 1.pdf) on the Jones Act indicates that, "On two occasions, in 1996 (P.L. 104-324) and again in 2011 (P.L. 112-61), Congress has permitted certain foreign-flagged liquefied natural gas (LNG) tankers to provide domestic service because none existed in the Jones Act fleet; [however] no ship owners have made use of these exemptions...There are no LNG tankers in the Jones Act fleet, and it is unclear why shippers have not utilized the 1996 or 2011 waivers for LNG tankers mentioned above. Puerto Rico, which currently imports LNG from Trinidad and Tobago, is seeking a 10-year waiver of the Jones Act to receive bulk shipments of LNG from the U.S. mainland."

PREB-PREPA-01-43 b) Siemens developed a cost estimate for an LNG FSRU (see response to PREB-PREPA-01-15 a)). To reiterate this response, the estimated costs for the ship-based LNG terminals (FSRU) were developed on the basis of two sources: (1) the July 2017 study conducted by The Oxford Institute for Energy Studies entitled "The Outlook for Floating Storage and Regasification Units (FSRUs)" (refer to file PREPA ROI_1_15 Attach 1.pdf), and (2) the June 2015 study prepared by Poten & Partners entitled "Interest in Floating Regas Units Grows in Asia" (refer to file PREPA ROI 1_15 Attach 2.pdf). In both studies, the cost of a converted LNG tanker was considered rather than a new build. In the Oxford study, the estimated cost to purchase and convert a used tanker to an FSRU is approximately $100-120 million (converted from £80-100 million). In the Poten & Partners study, the estimated cost to convert a full-size LNG tanker to an FSRU is $80 million. On the basis of these two studies and taking into account market comparables (see "Regasification Market Comparables" attached as PREPA ROI_1_43.xlsx), Siemens estimated that the capital expenditure for ship-based LNG delivery to Yabucoa and Mayagüez is $185 million. There are no further estimated costs for preliminary permitting and engineering costs or component-level estimates beyond these two studies and the market comparables.

**PREB-PREPA-01-44** **Refer to Page 7-11 of the IRP Main Report, regarding Ship-based LNG.**

**h) Provide the number of Jones Act compliant medium-scale (30,000 m3 – 60,000 m3) vessels.**

**i) Provide the number of Jones Act compliant large-scale (85,000 m3 – 170,000 m3) vessels.**

**j) Indicate if San Juan harbor meets the regulatory requirements to harbor medium and/or large-scale LNG vessels. If not, please explain.**

**k) Provide any reports, analysis, or other documentation that illustrates the relationship between LNG prices from U.S. mainland export terminals and LNG prices**

**offered by sellers exporting from other ports, in particular from Trinidad and Tobago.**

l) **In PREPA's or Siemens's experience, to what extent do U.S. export prices reflect Henry Hub or other mainland benchmarks, and to what extent do U.S. export prices reflect a global commodity market price for LNG? Provide any documents relied upon for this response.**

The following responses were provided by James Bowe, Partner, King & Spalding, and Petter Hubbard, Manager, Siemens. James Bowe and Peter Hubbard certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-44 a) Publicly available information PREPA has reviewed indicates that there are no Jones Act compliant medium-scale (30,000 $m^3$ – 60,000 $m^3$) LNG carrier vessels currently available. See response to PREB-PREPA-01-23 item a.

PREB-PREPA-01-44 b) Publicly available information PREPA has reviewed indicates that there are no Jones Act compliant large-scale (85,000 $m^3$ – 170,000 $m^3$) LNG carrier vessels currently available. See response to PREB-PREPA-01-23 item a.

PREB-PREPA-01-44 c) San Juan Harbor's size, configuration and water depths are adequate to accommodate LNG deliveries within the harbor by small-scale LNG bulk carriers. By Letter of Recommendation issued on September 26, 2018, the Captain of the Port, U.S. Coast Guard Sector San Juan, "convey[ed] the Coast Guard's recommendation that the waterways approaching and entering San Juan Harbor to Wharves A and B in Puerto Nuevo, Puerto Rico be considered suitable for LNG marine traffic."

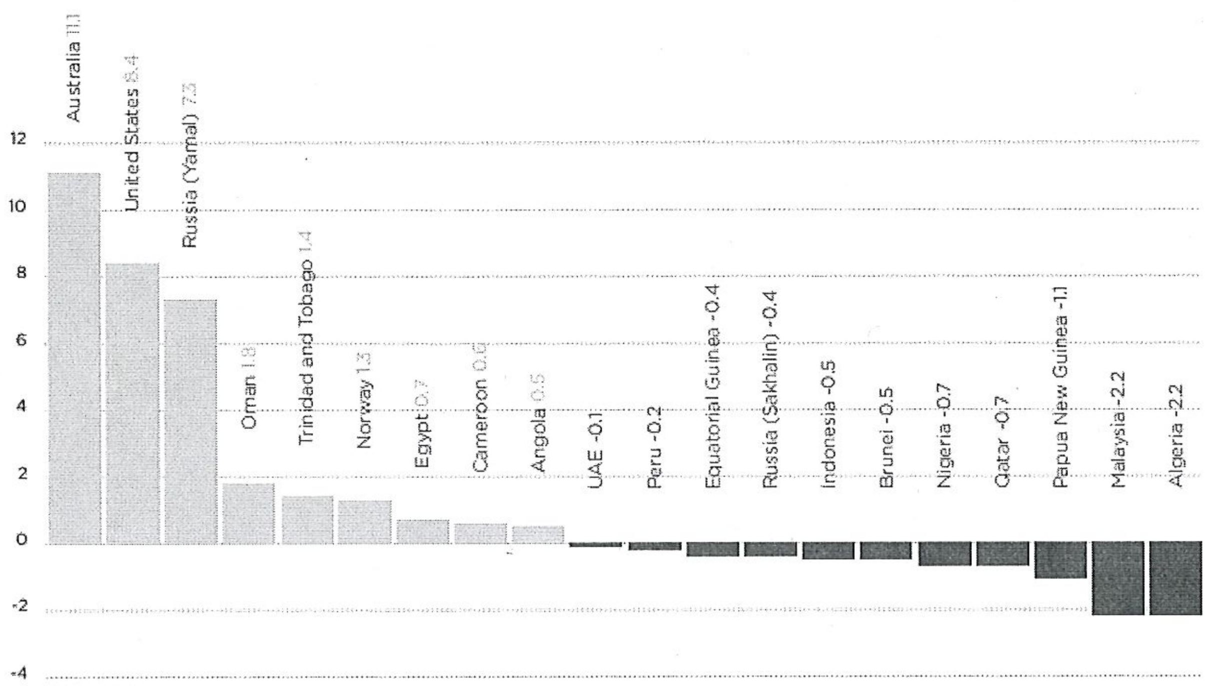
PREB-PREPA-01-44 d) As indicated in the IRP Main Report (at p. 7-26), Siemens expects that pricing of LNG delivered from sources such as Trinidad & Tobago will generally be competitive with the pricing of U.S.-sourced LNG. The IRP analyses incorporated U.S. Gulf Coast natural gas commodity prices (established by the U.S. benchmark Henry Hub) with the assumption that U.S. Gulf Coast LNG pricing and Trinidad & Tobago LNG pricing would face similar competitive pressures, which would bring pricing from U.S. sources and Trinidad and Tobago into rough alignment. Moreover, by focusing on U.S. Gulf Coast natural gas pricing, Siemens was able to utilize its fundamentals-based model (the Gas Pipeline Competition Model or GPCM.

Siemens has analyzed the relationship between prices for LNG sourced from U.S. mainland export terminals and LNG prices offered by sellers exporting from other ports, including Trinidad and Tobago, and as indicated expects that the pricing of LNG supplies from Trinidad and Tobago should tend torwards rough alignment with pricing from U.S. sources. The U.S. Gulf Coast pricing used in the IRP analyses assumes Henry Hub commodity cost pricing plus 15% plus $4.35/MMBtu to account for liquefaction, transport, and margin, which is a similar pricing formula to that used by large-scale U.S. Gulf Coast LNG offtakers. According to the U.S. DOE, vessel-borne imports of LNG to Puerto Rico from Trinidad and Tobago in the first five months of 2019 (total of 11 shipments) averaged a landed price of $8.32/MMBtu (see PREPA ROI_1_44 Attach 1.pdf, also available at https://www.energy.gov/fe/downloads/lng-monthly-2019). Compare this to the average Henry Hub price in the first five months of 2019 of $2.81/MMBtu (source: https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm), which with the 15% adder and the $4.35/MMBtu adder comes to $7.58/MMBtu or 9% lower than the delivered price of LNG from Trinidad and Tobago.

PREB-PREPA-01-44 e) As indicated in the IRP Main Report (at pp. 7-25 – 7-26), prices quoted for LNG sourced from U.S. mainland LNG export facilities often reference Henry Hub natural gas prices. This is true of the existing contract for deliveries of LNG to PREPA's Costa Sur generating facility, and of the contract between PREPA and New Fortress Energy for the supply of natural gas to the San Juan 5 & 6 units upon their conversion. A number of industry observers have noted that increasingly, the Henry Hub natural gas is being accepted as a global benchmark for the pricing of LNG, given growth of international demand for natural gas and a surge in shipments of U.S. gas in the form of LNG. See, e.g., CME Group, "LNG and the Importance of the Henry Hub Benchmark," The Street (Oct. 8, 2018), see file PREPA ROI_1_44 Attach 2.pdf.

The United States added significant new natural gas export capacity in 2018 compared to 2017. This is documented in a number of publications, including "The LNG Industry – GIIGNL Annual Report 2019," attached as PREPA ROI_1_44 Attach 3.pdf (available at: https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf) (the "GIIGNL Report") and is illustrated in the graph appearing below extracted from that report. Given the historically low prices for natural gas in the U.S. (*see, e.g.*, the attached IHS Market report, "LNG Market Profile – United States" (Sept. 7, 2018), designated as PREPA ROI_1_44 Attach 4.pdf), and an increasing proportion of spot trades, short-term contracts, and flexible destination contracts (see GIIGNL Report), U.S. LNG export pricing is becoming increasingly important in the global LNG trade.

SOURCE OF LNG IMPORTS: 2018 VS. 2017 (MT)




*Source: GIIGNL, Kpler*

**PREPA-PREB-01-45** **Refer to Page 7-11 of the IRP Main Report, regarding the San Juan and Palo Seco possible pipeline.**

**a) Provide the supporting documentation and analysis for the $35 million estimate for the 4.2-mile pipeline connecting the San Juan and Palo Seco plants.**

**b) Identify what permitting activities would need to be undertaken to construct a natural gas pipeline between the two plants.**

**c) Has PREPA or Siemens considered a ship-based option for LNG at Palo Seco? If not, why not? If so, explain why it was not included as an option in the analysis conducted to date and provide the analysis, costs, or other data used in this determination.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

PREB-PREPA-01-45 a) The original analysis for the 4.2-mile pipeline from San Juan to Palo Seco plant comes from the 2015 Galway report, which considered an onshore pipeline along one of two routes: Highway 165 (Avenida El Cano) or the previously contemplated Via Verde route closer to the industrial areas but still with the potential for impacts on wetlands and/or other environmentally sensitive areas. In the 2015 IRP, the estimated capital cost for this 4.2-mile pipeline was $65 million. However, Siemens revised this figure downward to $35 million on the basis that the route is along an existing right-of-way and based on recent land construction costs for pipelines. The source for updated construction cost estimates ($8.5 million per mile) came from a survey of costs collected and published by Oil & Gas Journal, an excerpt of which is copied below and can also be found at this website: https://www.ogj.com/pipelines-transportation/pipelines/article/17232529/pipeline-operators-net-incomes-rise-sharply.

**10 YEARS OF LAND CONSTRUCTION COSTS[1]**

Table 5

| Size | Year | ROW | Material | Labor | Misc. | Total | Low | High |
|---|---|---|---|---|---|---|---|---|
| | | Average cost, $/mile | | | | | Range, $/mile | |
| 16 in. | 2018 | 82,364 | 1,769,980 | 5,282,562 | 8,599,804 | 15,734,710 | 13,237,381 | 18,731,540 |
| | 2017 | 66,012 | 305,167 | 35,116 | 890,797 | 1,297,093 | 1,278,464 | 5,384,618 |
| | 2016 | 267,288 | 415,979 | 1,937,269 | 1,473,663 | 4,094,199 | — | — |
| | 2015 | 357,891 | 380,604 | 1,395,814 | 2,180,469 | 4,314,779 | 3,175,990 | 14,996,594 |
| | 2014 | 574,745 | 483,528 | 2,911,085 | 2,807,562 | 6,776,920 | 6,471,863 | 7,325,147 |
| | 2013 | 81,810 | 786,739 | 533,749 | 636,324 | 1,538,623 | 1,005,653 | 5,882,153 |
| | 2012 | 126,033 | 302,558 | 748,967 | 302,760 | 1,480,318 | — | — |
| | 2011 | 278,231 | 305,235 | 1,004,152 | 1,328,691 | 2,916,309 | 2,007,514 | 3,885,413 |
| | 2010 | 263,135 | 222,719 | 885,769 | 966,447 | 2,338,069 | — | — |
| | 2009 | 226,517 | 417,899 | 1,480,926 | 586,626 | 2,711,968 | — | — |
| 20 in. | 2018 | — | — | — | — | — | — | — |
| | 2017 | 66,012 | 305,167 | 35,116 | 890,797 | 1,297,093 | 1,278,464 | 5,384,618 |
| | 2016 | 199,333 | 329,680 | 2,728,127 | 1,740,590 | 4,997,730 | 4,457,245 | 5,142,938 |
| | 2015 | 324,055 | 425,218 | 985,093 | 1,689,816 | 3,424,182 | 2,476,789 | 6,049,136 |
| | 2014 | 473,329 | 632,417 | 2,264,767 | 2,142,928 | 5,513,441 | 2,723,642 | 11,975,448 |
| | 2013 | 103,333 | 338,025 | 998,560 | 701,317 | 2,141,235 | — | — |
| | 2012 | 8,941 | 275,292 | 69,647 | 1,349,884 | 1,703,766 | — | — |
| | 2011 | 97,553 | 402,232 | 1,208,048 | 816,998 | 2,524,831 | 1,773,309 | 7,970,976 |
| | 2010 | 64,198 | 1,194,239 | 1,663,457 | 1,504,568 | 4,426,461 | — | — |
| | 2009 | 164,377 | 820,867 | 1,993,079 | 1,061,331 | 4,039,654 | 3,866,474 | 7,528,043 |

PREB-PREPA-01-45 c) The 2015 Galway report considered several options for supplying vaporized LNG or depressurized CNG to Palo Seco, including an FSRU with subsea pipeline to Palo Seco. This option was considered by Galway to have a potentially high impact in terms of dredging and disposal impact (it would cross a coral reef area) and would be difficult to permit because of the proximity to roads and industrial sources. Ultimately, the Galway report identified and considered 14 options for supplying fuel to San Juan and Palo Seco plant, but discarded all options except one: the more traditional land-based LNG import terminal storage and vaporization configuration at the Warehouse Site adjacent to the San Juan plant (Option 14).

The following response was provided by Luisette X Ríos Castañer, Head Environmental Protection and Quality Assurance Division, PREPA, and Peter Hubbard, Manager, Siemens. Luisette X Ríos Castañer and Peter Hubbard certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-45 (b) In terms of permitting for an onshore pipeline, the Galway report identified the U.S. Department of Transportation (DOT) Pipelines and Hazardous Materials Safety Administration (PHMSA) as a key regulatory agency that would issue a permit for such a pipeline. Permitting activities to construct a natural gas pipeline between San Juan and Palo Seco may require federal agencies to prepare an Environmental Impact Statements (EIS) or an Environmental Assessments (EA). The EIS may take between 1 to 2 years; an EA may take up to 6 months. Refer to PREPA ROI_1_45 Attach 1.pdf for an updated document of permits that might be necessary to bring natural gas through pipelines to the power plant. Depending on the route selected are the studies and permit requirements that the agencies may require. Time included is approximate.

**PREB-PREPA-01-46** **Refer to Page 7-11 of the IRP Main Report, regarding Ship-based LNG San Juan. Please indicate if PREPA has calculated the required number of shipments to meet a projected natural gas need of: (i) 50.4 MMcf/d, and (ii) 93.6 MMcf/d for the plants located in San Juan. If so, please provide the calculation and supporting documentation. If not, please explain why not.**

The following response was provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** The figures cited on Page 7-11 are based on an estimated 350 MW gas-fired capacity at San Juan, which would require an expected daily gas volume of 50.4 MMcf/d. If a pipeline to the Palo Seco plant is included, adding an incremental 302 MW of gas-fired capacity at Palo Seco plant, the expected daily gas volume requirement would increase to 93.6 MMcf/d. A mid-scale (Type C - 30,000 $m^3$) LNG carrier would deliver approximately 651.6 MMcf/d of natural gas, using a conversion factor of 21,719 cf per $m^3$ of LNG. To satisfy San Juan's fuel requirements of 50.4 MMcf/d, this would require a shipment every 12.9 days or 29 shipments per year (rounding up). To satisfy San Juan and Palo Seco's fuel requirements of 93.6 MMcf/d, this would require a shipment every 7.0 days or 53 shipments per year (rounding up).

**PREB-PREPA-01-47** **Refer to Page 7-11 of the IRP Main Report, regarding the pipeline from EcoEléctrica to San Juan.**

a) **Please indicate if PREPA has conducted an analysis of the feasibility of a pipeline from the EcoEléctrica import terminal to San Juan. If so, please provide a copy of the analysis.**

b) **Please indicate if PREPA has estimated the cost of a pipeline from the EcoEléctrica import terminal to San Juan. If so, please provide a copy of the estimated cost.**

c) **Please describe the direct pipeline route from EcoEléctrica to San Juan.**

**d) Please indicate if PREPA has conducted an analysis of the feasibility of a pipeline from the EcoEléctrica import terminal to San Juan via Aguirre. If so, please provide a copy of the analysis.**

**e) Please indicate if PREPA has estimated the cost of a pipeline from the EcoEléctrica import terminal to San Juan via Aguirre. If so, please provide a copy of the estimated cost.**

**f) Please describe the direct pipeline route from EcoEléctrica to San Juan via Aguirre.**

**g) Please describe the permits that would be required and a project timeline for both pipeline proposals.**

**h) Please indicate if a natural gas pipeline from EcoEléctrica to San Juan via Aguirre would also serve the Aguirre plant. If so, please indicate if PREPA has estimated the additional natural gas requirements for supplying Palo Seco, San Juan, and Aguirre units.**

**i) Please provide a copy of all analyses undertaken or commissioned by PREPA for the natural gas requirements required for a pipeline connecting EcoEléctrica to San Juan via Aguirre.**

The following responses were provided by Luisette X Ríos Castañer, Head Environmental Protection and Quality Assurance Division, PREPA. Luisette X Ríos Castañer certifies that, to the best of her information and belief, all answers provided by her herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-47 a) A study for a North Coast Pipeline was prepared by Power Technologies Corporation in August 2008. A voluminous hardcopy exists which PREPA can make available for review at the earliest convenience.

PREB-PREPA-01-47 b) Please refer to answer PREB-PREPA-01-47 a) above.

PREB-PREPA-01-47 c) Please refer to answer PREB-PREPA-01-47 a) above.

PREB-PREPA-01-47 d) The study prepared by Power Technologies Corporation in August 2018 included pipeline corridors and specific route alignments from Aguirre to San Juan. PREPA can make the report hardcopy available at the earliest convenience.

PREB-PREPA-01-47 e) Please refer to answer PREB-PREPA-01-47 d) above.

PREB-PREPA-01-47 f) Please refer to answer PREB-PREPA-01-47 d) above.

PREB-PREPA-01-47 g) Refer to PREPA ROI_1_45 Attach 1.pdf for an updated document of permits that might be necessary to bring natural gas through pipelines to the power plant. Depending on the route selected are the studies and permit requirements that the agencies may require. Time included is approximate.

PREB-PREPA-01-47 h) Please refer to answer PREB-PREPA-01-47 d) above.

PREB-PREPA-01-47 i) Please refer to answer PREB-PREPA-01-47 d) above.

**PREB-PREPA-01-48** **Refer to Page 7-12 of the IRP Main Report, regarding the San Juan warehouse district. Please indicate if PREPA would be required to purchase additional land in San Juan in order to site an onshore LNG terminal in San Juan. If so, please indicate if additional real estate and permitting costs have been factored in PREPA's estimated cost for a San Juan LNG terminal.**

The following response was provided by José Vazquez Vera, Superintendent, PREPA. José Vazquez Vera certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** For an onshore LNG terminal in San Juan, additional land will be required to locate both the tank and related infrastructure, including the resulting buffer or exclusion zones. It has been identified that the land in the vicinity of the San Juan Power Station is government-owned by one or more agencies or public corporations, such as the Puerto Rico Ports Authority, Puerto Rico Land Administration, and PRIDCO. Proper coordination is to be established with those agencies and public corporations, in order to allocate the required land by either transfer or purchase. Estimated costs for land transfer transactions within government agencies and /or government-owned corporations are not included in the project cost estimate.

**PREB-PREPA-01-49** **Refer to Page 7-12 of the IRP Main Report, regarding the Shuttle tankers.**

**a) Under the shuttle tank scenario described in the Galway analysis, please indicate if the LNG shuttle tankers would need to be Jones Act compliant. If so, please indicate if PREPA is aware of any Jones Act LNG shuttle compliant vessels available to meet PREPA's projected need.**

**b) Please indicate if the capital and/or operational costs associated with LNG shuttle vessels have been included in PREPA's LNG infrastructure estimates. If so, please provide a copy of the estimates with supporting calculations and documentation.**

The following response was provided by Peter Hubbard, Manager, PREPA. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-49 a) Currently, LNG shuttle tankers would need to be Jones Act compliant, in the absence of a Jones Act waiver. Siemens is not aware of any LNG shuttle vessels that are currently Jones Act compliant. A May 2019 Congressional Research Service report (Refer to file PREPA ROI_1_49 Attach 1.pdf) confirms that no LNG shuttle vessels are currently Jones Act compliant. Siemens understands that Puerto Rico submitted a request in December 2018 to the current U.S. Government administration for a Jones Act waiver to be able to procure LNG from the U.S. mainland, but the administration has not yet taken action on this request.

PREB-PREPA-01-49 b) The capital costs associated with LNG shuttle vessels were not included in PREPA's LNG infrastructure estimates. However, the $4.35/MMBtu adder that is included in the delivered LNG fuel price to Puerto Rico assumes transportation of LNG via LNG shuttle vessel from the U.S. Gulf Coast. The cost components of the $4.35/MMBtu adder include $2.80 for liquefaction, $1.00 for transport on a shuttle-style 30,000 $m^3$ LNG tanker, and $0.55 for margin (profit).

**PREB-PREPA-01-50** **Refer to Page 7-20 of the IRP Main Report, regarding Henry Hub Natural Gas.**

**a) Indicate if the Siemens GPCM® tool has the capability to model gas prices at the Aguirre delivery point.**

**b) Indicate if Siemens model gas prices at the Aguirre delivery point in GPCM®. If so, please provide results of the delivery point modeling. If not, please explain why not.**

**c) Indicate if Siemens model gas prices for proposed delivery points across the island. If so, please provide the results of any additional GPCM® analyses.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-50 a) The GPCM® tool is a fundamentals-based model focused on continental North American supply, demand, and natural gas infrastructure. The GPCM® tool is an industry-standard tool widely used by utilities, natural gas production firms, consultants, and other market participants. Siemens uses the non-proprietary GPCM® tool and customized the inputs database with its own assumptions in order to create a proprietary database with forecasts of prices and other outputs.

PREB-PREPA-01-50 b) The GPCM® tool does not include the capability to model gas prices delivered to Puerto Rico. Rather, Siemens estimated natural gas prices at the Aguirre delivery point on the basis of a comparison with liquefaction, delivery, and margin (profit) cost estimates from U.S. Gulf Coast LNG export facilities. The cost components of the \$4.35/MMBtu adder (in addition to the Henry Hub commodity cost) include \$2.80 for liquefaction, \$1.00 for transport on a shuttle-style 30,000 m$^3$ LNG tanker, and \$0.55 for margin (profit).

PREB-PREPA-01-50 c) Siemens used the GPCM® tool to develop the base commodity forecast of natural gas prices at the benchmark Henry Hub. Siemens then added \$4.35/MMBtu that includes \$2.80 for liquefaction, \$1.00 for transport on a shuttle-style 30,000 m$^3$ LNG tanker, and \$0.55 for margin (profit). This methodology served as the basis for estimate delivered LNG prices to all delivery points across the island of Puerto Rico.

**PREB-PREPA-01-51** **Refer to Page 7-25 of the IRP Main Report, regarding San Juan/ Palo Seco, Mayagüez, and Yabucoa delivered natural gas price.**

**a) Provide the basis and supporting evidence why the forecasted delivered natural gas price for the proposed San Juan/ Palo Seco, Mayagüez, and Yabucoa plants be lower than the delivered natural gas price for Costa Sur 5 and 6.**

**b) Indicate if Siemens modeled different assumptions for liquefaction, transport, and margin adders in its analysis. If so, please provide a copy. If not, please explain why not.**

The following responses were provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-51 a) In developing the forecasted delivered natural gas prices to Puerto Rico, Siemens assumed that the San Juan / Palo Seco, Mayagüez, and Yabucoa plants (as well as Aguirre) would follow the Costa Sur / EcoEléctrica contracted pricing through 2021. Beginning in 2022, the EcoEléctrica fuel supply contract ends and the price forecast reverts to the fundamentals-based outlook developed using the GPCM® tool with the \$4.35/MMBtu adder for liquefaction, transport, and margin.

PREB-PREPA-01-51 b) The San Juan / Palo Seco, Mayagüez, Yabucoa, and Aguirre delivery points are all assumed to have the same \$4.35/MMBtu adder for liquefaction, transport, and margin, and accordingly have identical delivered fuel price forecasts. This assumption is included in the attached 2018 IRP Fuel Forecast spreadsheet on the Delivered Fuel Forecast tab.

**PREB-PREPA-01-52** **Refer to Page 7-31, Exhibit 7-14, of the IRP Main Report. Confirm that the EcoEléctrica delivered natural gas price shown in Exhibit 7-14 follows the same formula as the delivered natural gas price of Costa Sur 5 and 6 of 115% times Henry Hub plus $5.95.**

The following response was provided by Peter Hubbard, Manager, Siemens. Peter Hubbard certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** The pricing formula used for delivered natural gas to Costa Sur units 5 and 6 is shown below. The Henry Hub component is only 50% of the price formula, while No. 6 fuel oil is the other 50%. The forecast for delivered natural gas to EcoEléctrica when the capacity factor is equal to or greater than 76 percent (>=76%) is assumed to follow that of Costa Sur through the end of 2021. When the capacity factor is less than 76 percent (<76%), EcoEléctrica delivered natural gas prices follow the formula: 0.033725*(CPI for 2017 / CPI for Base Year 2003)*0.5 + 0.01957*(Prior Year Henry Hub price / 1.99930695)*0.5. In both cases (all capacity factors), the delivered natural gas to EcoEléctrica in 2022 and beyond is assumed to revert to a fundamentals-based price outlook, which is the same as the delivered pricing to all delivery points on the island.

*Contract Price Tier 3 (US$/MMBtu) = 50% P1 + 50% P2*

*Where:*

***P1***= *12.15% F#6603 + 1.125*

*F#6603 (in US$/bbl) is the unweighted average for the 6-month period prior to the relevant quarter of the mean dated fuel with zero point five percent (0.5%) sulfur as interpolated from the means of zero point three percent (0.3%) sulfur LP and zero point seven percent (0.7%) sulfur fuels, as published by the Platts's Oilgram Price Report PRICE AVERAGE SUPPLEMENT, Estimated New York spot No. 6 Fuel Oil Cargo columns, rounded to two (2) decimal places".*

***P2***= *115% HH + 5.95*

*HH (in US$/MMBtu) is the final settlement price for the New York Mercantile Exchange's Henry Hub natural gas futures contracts for the month previous to the month of delivery, rounded to two (2) decimal places".*

**PREB-PREPA-01-53** **The following questions are related to the Aurora Nodal Analysis – Congestion and Price Data.**

a) **Provide the nodal analysis hourly file for S1S2B.**

b) **Confirm that the first line of text under Page 8-71, Section 8.4.7 "Nodal Analysis of the S1S2B", of the IRP Main Report is referring to Scenario 1, not Scenario 3.**

c) **For each of the four nodal analysis files provided, and for a nodal analysis file for Scenario 1 (S1S2B), supplement the provided hourly data for 2025 and 2028 with (i) the system price (with energy, congestion and loss components, if/as available) and (ii) the locational prices, (also with components) at least on a "minigrid" or other zonal configuration basis.**

d) **Refer to Page 10, line 203, of PREPA Ex. 6.0, Direct Testimony of Dr. Bacalao. Confirm, as stated the referred testimony that the transmission congestion is generally absent. Provide detailed explanation if the nodal analysis results do not show generally absent transmission congestion.**

The following responses were provided by Nelson Bacalao Senior Manager, Siemens, and Dan Yu, Staff Consultant, Siemens. Nelson Bacalao and Dan Yu certify that, to the best of their information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-53 a) Please refer to file PREPA ROI_1_53 Attach 1.xlsx

PREB-PREPA-01-53 b) The first line of text under Page 8-71, Section 8.4.7 "Nodal Analysis of the S1S2B" should refer to Scenario 1.

PREB-PREPA-01-53 c) Please refer to the following attachments for LMP data (energy, congestion and loss components) for the system and nodal aggregated areas of Arecibo, Bayamon, Caguas, Carolina, Mayaguez, Ponce-ES, Ponce-OE and San Juan. The system LMP and its components were derived using load weighted prices of the nodal aggregated areas.

PREPA ROI_1_53 Attach 2.xlsx (for ESM)

PREPA ROI_1_53 Attach 3.xlsx (for S1S2B)

PREPA ROI_1_53 Attach 4.xlsx (for S3S2B)

PREPA ROI_1_53 Attach 5.xlsx (for S4S2B)

PREPA ROI_1_53 Attach 6.xlsx (for S5S1B)

PREB-PREPA-01-53 d) Transmission congestion is generally absent in the nodal scenarios simulated, except for S3S2B. As shown in the hourly LMP data for 2025 and 2028 provided in response to PREB-PREPA-01-53-c, the marginal cost of congestion ("MCC") spread between the nodal aggregated areas are very minimal.

ESM – average MCC spread of less than $0.03 for both years.

S1S2B – average MCC spread of less than $0.09 for both years.

S3S2B – average MCC spread of less than $0.19 for 2025. For 2028, average MCC spread increased to $4.22 due to increased congestion on the Cana-Bo Piñas 138 kV line (modeled at 80% rating) under separate contingencies of Bayamon-Manati 230 kV and Costa Sur-Aguirre 230 kV. This is a currently a known constraint on the system. The increase in congestion is likely due to the placement of the Solar PV which is not known in detail at the moment.

S4S2B – no congestion was seen for this scenario for both years.

S5S1B - average MCC spread of less than $0.02 for both years.

**PREB-PREPA-01-54** **Exhibit 8-3 of the IRP Main Report illustrates that Scenario S3S2S8B is a lower NPV cost than the ESM plan; and when including the "NPV Deemed Energy Not Served" component, S3S2S8B is lower cost than either the ESM plan or S4S2. On Page 8-72 of the IRP Main Report, the text states that Scenario 3 implementation "would be a significant challenge and could be difficult to achieve for practical reasons" and also states that implementation would put "strain and reliance on the energy storage".**

a) **Provide the specific underlying economic rationale for not choosing the lower cost Scenario 3 (S3S2S8B, or S3S2B) as part of a preferred resource plan.**

b) **Explicitly state all "practical reasons" that implementation of this scenario would be a challenge other than those reasons based on "strain and reliance on the energy storage".**

c) **Explicitly state what is meant by "strain and reliance" on the energy storage? In particular, explain in your answer if this is a reference to battery energy storage systems operating outside of their design and operating regime. f not, explain what form of strain and reliance underpins the concern that system operation would be a challenge. f so, explain why the analyses assume battery energy storage systems operating outside of their design attributes or operating regimes.**

d) **The Metrics file for Scenario 3, Strategy 2 (base) indicates zero loss of load hours in all years for this scenario. Reconcile the "challenge" noted above with the results indicating load is met in all hours.**

e) **Is the reference to "strain and reliance" only for Scenario 3? Does it not apply to the other scenarios that also incorporate substantial amounts of battery storage? Is there a threshold level of battery storage system installation that PREPA or Siemens sees as the point at which operational challenges are unacceptable to ensure reliable operation? If so, please provide all analyses or explanation of why certain threshold levels apply. If not, then explain why operations will be challenged with high levels of battery storage.**

The following responses were provided by Nelson J Bacalao, Senior Manager Consulting, Siemens. Nelson J Bacalao certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB_PREPA-01-54 a): If Scenario 3 assumptions on low cost of renewable materialized over the planning period from a purely economic point of view this would be a preferred resource plan and we incorporate it indirectly when we express that it provides an indication of a future development if these lower cost did materialize and the renewable implied by the plan could be effectively be incorporated. However, if the renewable capital cost were equal to our base forecast then this plan (S3S2S8B) would have similar present value as for example the S4S2B; $14.36 billion versus $14.35 billion, but its capital cost is 28% higher and would be heavily affected by higher (than the base) renewable prices. In summary this plan shows a potential path forward if the cost assumptions and integration do materialize. Finally, it should be indicated that in the short term, both the S3S2B and S3S2B call for important levels of PV (2,820 MW and 2,220 MW) and have the same storage levels (1,320 MW), so the key differentiator between these plans in the short term decisions is that S4S2B does call for the development of the new CCGT in the north (Palo Seco), while in S3S2B this is not developed and large amounts of PV are installed after 2025 (4,140 MW by 2038 in S3S2B).

PREB_PREPA-01-54 b): In S3S2B the amount of PV 4,140 MW is 233% of the expected peak demand over the long term (1,780 MW) and the storage 3,040 MW is 171% of the peak demand. This means that daytime hours the PV will be several times the system load and most of it will be going to storage, that is expected to manage its intermittency. There is no experience with these levels of generation and in general we found that the dispatch models have difficulty in finding a solution. So, we are not assuming that the storage is not working properly, we are basically concerned on the practical feasibility of running such system. In fact, the comparable values for S4S2B are also challenging; 2,820 MW of PV equal to 159% of the demand long term and 1,614 MW of storage 92% of the demand and we suggest caution and have a learning curve as we integrate these levels of renewable.

PREB_PREPA-01-54 c): The main practical reason for this plan not to be selected as the preferred plan was its high reliance on low cost of renewable as mentioned above and the associated risk of this not being the case. Other practical problem is the dependence on PV and over the long term the entire installed thermal capacity in this plan would only cover 44% of the expected peak demand versus 62% in the S4S2B.

PREB_PREPA-01-54 d): Yes, that is correct, and this is the result of the simulations. However, these simulations assume perfect operation of the resources and as mentioned above this can be challenging given how much larger is the PV and storage with respect of the load served. In fact, if the storage is not managed properly (optimized commitment), we have seen unexpected results as energy not served in the early hours of the day as storage became depleted due to excessive use during the night peak.

PREB_PREPA-01-54 e): We measure the technology risk that is behind the "strain and reliance" by a ratio of the installed PV to the peak demand and this value is 232% in S3S2B while in S1S2B, S4S2B, S5S1B and ESM is 150% and as mentioned above we find that these values can make the operation challenging already, thus going to 232% we find it extreme. Considering the storage necessary for the integration of this resource we arrive at similar conclusions in the S3S2B storage is 171% of the peak demand (almost twice), while the average of the other scenarios is 81%, highlighting the much greater reliance of Scenario 3 on storage as compared with other cases and of course actual experience in the industry.

**PREB-PREPA-01-55** **The questions below relate to the Scenario Results Peaker Builds.**

**a) Why does S3S2S8B build 357 MW of peakers (similar to Scenario 4), while exhibiting a "lowest reserve margin" of 48%, above the threshold reserve margin capacity?**

**b) Is the peaker build for S3S2S8B, and Scenario 4, due solely or primarily to the Strategy 2 local reserve margin constraint presence? Explain in detail.**

The following responses were provided by Nelson Bacalao Senior Manager Consulting, Siemens. Nelson Bacalao certifies that, to the best of his information and belief, all answers provided by them herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-55 a): As was indicated in the IRP report; Section 5.4 "Peaking generation was added to all LTCEs under Strategy 2 and Strategy 3 to ensure that the critical loads located in each of the recommended eight electric islands into which the system would be segregated after a major storm (the MiniGrids), could be served on grid isolated mode. The bulk of the 357 MW of peaking generation added by S3S2S8B correspond to this generation as shown in the table below and they are all required to meet the expected levels of critical load after a major event with local thermal resources.

| Area | Units | MW |
|---|---|---|
| CAGUAS | 4 | 93 |
| CAROLINA | 4 | 93 |
| CAYMG | 1 | 24 |
| MAYAGUEZ | | |
| NTH | 3 | 70 |
| PONCE ES | 2 | 46 |
| Total | 14 | 325 |

In addition to the above the LTCE does install a couple of diesel peakers in 2028 (32 MW), probably related with the integration of renewable as the reserves are fairly high that year (63%) but on the other hand 600 MW of PV are placed in service to address the retirement of AES Coal.

PREB-PREPA-01-55 b): No, it is not related to reserves under Strategy 2 but rather the input that critical loads to be served with thermal resources.

**PREB-PREPA-01-56** **The questions below relate to the NPV of Scenario Results and Exclusion of Transmission/Minigrid costs.**

**a) Confirm, or explain otherwise, that the NPV's listed in Exhibit 8-3 of the IRP Main Report exclude any transmission costs associated with either minigrid or non-minigrid transmission infrastructure build out.**

**b) What is the applicable NPV of transmission costs that would apply to each Scenario? Explain and provide all quantitative detail and workpapers.**

The following responses were provided by Yan Du, Staff Consultant, SiemensEnergy. Yan Du certifies that, to the best of his information and belief, all answers provided by him herein are true and no false or misleading information has been provided.

**Response:** PREB-PREPA-01-56 a) No, it does exclude the transmission cost.

PREB-PREPA-01-56 b): The NPV of the transmission costs applies to applies to all the scenarios otherwise there will be much larger value of Energy Not Served as illustrated in the VoLL analysis of Carolina MiniGrid. See Confidential-PREPA ROI_1_56 Attach 1.xlsx for a calculation of the NVP.