PREPA Ex. 9.0

COMMONWEALTH OF PUERTO RICO

PUERTO RICO ENERGY COMMISSION

IN RE: THE PUERTO RICO ELECTRIC POWER AUTHORITY	**No.** CEPR-AP-2015-0001
INITIAL RATE REVIEW	**SUBJECT:** TESTIMONY IN SUPPORT OF PETITION

Direct Testimony of

RALPH ZARUMBA

Director, Navigant Consulting, Inc.

On behalf of the

Puerto Rico Electric Power Authority

May 27, 2016

TABLE OF CONTENTS

I. INTRODUCTION

A. Witness Identification

Q. Please state your name, title, employer, and business address.

A. I am Ralph Zarumba and I am a Director at Navigant Consulting, Inc. ("Navigant"), a global business and advisory firm. My business address is 30 S. Wacker Drive, Suite 3100, Chicago, Illinois 60606.

Q. Please state your name, title, employer, and business address.

A. I am Ralph Zarumba and I am a Director at Navigant Consulting, Inc. ("Navigant"), a global business and advisory firm. My business address is 30 S. Wacker Drive, Suite 3100, Chicago, Illinois 60606.

B. Summary of Direct Testimony

Q. What are the purposes and subjects of your testimony?

A. I am testifying in support of PREPA's Petition requesting that the Puerto Rico Energy Commission (the "Commission") approve and establish new rates for PREPA. More specifically, the purpose of my testimony is to present and support PREPA's Marginal Cost of Service Study ("MCOSS"). The MCOSS was prepared properly and it meets the objective(s) of identifying the value of incremental costs required to serve new load.

C. Professional Background & Education

Q. Please state your professional background.

A. My resume, which reviews my education, professional qualifications, and experience in detail, is attached is PREPA Exhibit ("Ex.") 4.01.

D. Additional Attachments

Q. Besides your resume, are there any additional attachments to your direct testimony?

A. Yes. The following additional exhibits are attachment to my direct testimony:

- PREPA Ex. 9.02: Distribution Investments
- PREPA Ex. 9.03: Transmission Investments
- PREPA Ex. 9.04: Marginal Cost of Service Study Results

II. DESCRIPTION OF THE MARGINAL COST OF SERVICE STUDY

Q. Please describe what is an MCOSS?

A. In brief, an MCOSS provides estimates of the cost to provide the next unit of electric service which is consumed by the customer. Mathematically, MCOSS is defined as the first derivative of the Total Cost Function – in other words, the incremental change in cost – when the quantity of service that is being measured is allowed to change by one. Average Cost – which is calculated in the Embedded Cost of Service Study supported by PREPA witnesses Ralph Zarumba and Eugene Granovsky, PREPA Ex. 8.0, is the total cost divided by the total quantity produced. Economic theory tells us that marginal costs are important because they indicate to the utility and customers what cost impact an increase or decrease in usage would have on the total revenue requirement of the utility. For a complete discussion of the supporting theory of marginal costs I recommend Alfred Kahn's seminal work *The Economics of Regulation.*

Q. Why is an MCOSS provided in this proceeding?

A. Marginal costs were prepared for this filing to determine the additional cost to serve new load, albeit during a timeframe when total electric demand is forecast to decline.[1] It also provides data for appropriate price signals that may be employed in relation to demand-side programs or third-party generation.

Q. What are the components of the MCOSS?

A. The Marginal Cost of Service Study follows the functions of an electric utility. A vertically integrated utility such as PREPA provides:

1. Generation Service. The generation function is analyzed as marginal generation capacity costs and marginal energy costs;
2. Transmission Service. The transmission function only contains a capacity component; and
3. Distribution Service. The distribution costs are analyzed by voltage level as well as differentiated by demand related and customer related.

The following sections of my testimony walk through the calculation of marginal costs associated each of these services.

III. MARGINAL GENERATION SERVICE COSTS

A. Marginal Generation Capacity Costs

Q. Please define Marginal Generation Capacity Costs ("MGCC").

[1] This marginal cost analysis was prepared using a load forecast that was available at the time. It is the same forecast that originally was used by outside experts (Siemens) in the pending "Integrated Resource Planning" or IRP case.

A. MGCC are defined as the cost to add new generating capacity to serve an additional kilowatt ("kW") of load. The MGCC is the cost of maintaining electric generation ready to serve load on demand regardless of the price or quantity of energy produced.

Q. Please provide background on the environment for generation capacity in Puerto Rico as reflected in the marginal cost analysis?

A. The environment for generation capacity in Puerto Rico can be defined as follows:

1. The Island is projected to have reduced load in the near and intermediate term.
2. Presently, PREPA's "firm[2]" reserve margin for generation resources effectively is about 30 percent. This margin is consistent with reliability studies that identify the percent reserves needed to meet a Loss of Load Hours ("LOLH") expectation of 4 hours per year, which is roughly equivalent to a Loss of Load Expectation ("LOLE") of 2 days per year. Inasmuch as island electric systems require a higher reserve margin in order to maintain a reasonable level of reliability PREPA's reserve margin, it significantly exceeds what is considered a "normal" reserve margin in larger interconnected systems such as those located in contiguous areas in North America.

[2] Firm reserves is an approximation derived by subtracting the system peak load from the sum of the product of the installed capacity and availability of each generating unit. For PREPA, it is close to twice the size of the largest generating unit in its system (Aguirre 1& 2 450 MW). Actual minimum reserves could exceed this value. To achieve a LOLH of four hours or less, firm reserves as defined above must exceed 25 percent. Accordingly, a 30 percent reserve margin was deemed to be the minimum generating reserves needed to meet the 4-hour LOLH criterion.

3. Inasmuch as generation investments are proposed in PREPA's Integrated Resource Plan (IRP) these investments are being made for reasons other than to serve load growth – they are being made in order to:
    - Achieve legally mandated environmental policies:
    - Maintain local reliability;
    - Integrate renewables, including distributed generation;
    - Improve efficiency; and
    - Reduce energy costs.
4. In the past several years, the use of Distributed Energy Resources ("DER") has expanded in Puerto Rico. Examples of DER include cogeneration and rooftop photovoltaic ("PV") generation. The DER technologies include those that produce power intermittently, such as solar PV, which may require back-up support from conventional generation to meet reliability targets.

Q. **How does the generation capacity environment impact the approach used for estimating the MGCC adopted in your testimony?**

A. The environment (see the factors above) impacts MGCC is in two ways. First, it impacts the technology adopted as the marginal generation unit. Second, it impacts the timing of when new generation is required, which in turn impacts estimated MGCC costs. The environment reflected in the marginal cost analysis is one in which peak load is expected to decline, which lessens the demand for new generating capacity. This lower demand, in turn, decreases the marginal cost and capacity value of new generation.

Q. What technology was adopted in estimating MGCC?

A. Navigant analyzed all generation technologies, which could reasonably be used in Puerto Rico and determined that a Wartsila model 18V50Sgg reciprocating engine generation unit is appropriate for purposes of estimating MGCC. A reciprocating engine, the Wartsila model 18V50SG technology, was chosen rather than a simple-cycle combustion turbine because it is the lowest cost alternative to supply capacity independent of the value of the energy output of a generating unit. The characteristics of this technology are summarized in the table below. Please note that PREPA is not recommending use of reciprocating engines in the pending IRP case for reasons discussed therein. In brief, different options are recommended in the IRP not only to provide capacity, but also to provide energy, and this combination of these factors resulted in the selection of combined cycle options.

Item	Units	Assumed Value
Installed Cost	2017$/kW-year	$1,124
Annual Fixed O&M	2017$/kW-year	$18.00
Economic Life	Years	20

Q. The installed cost of the Wartsila model 18V50Sgg reciprocating engine generation unit is a one-time cost. However, the generating unit provides service over several years. What approach was used to recognize the cost of the asset over the 20 year life?

A. An accounting Fixed Charge Rate ("FCR") was calculated, which levelized the total cost of the generating unit, including both capital recovery and Operations and Maintenance ("O&M") over the life of the asset. The assumptions used in the FCR calculation are consistent with those used in the PREPA's IRP.

Q. When will PREPA require new generation capacity to serve load?

A. No new generation capacity is needed to serve new load (as distinct from other purposes) over the planning horizon, which is 20 years. New generation is proposed to comply with legal requirements and for other non-capacity purposes, such as efficiency and renewables integration, as noted earlier and which is addressed in the IRP case.

Q. How have you adjusted the MGCC to reflect the distant need for generation capacity for load?

A. One approach would be to state that because generation is not required for load in the planning horizon, it has no value during this time frame. Although this is a reasonable assumption given the PREPA load forecast employed in the marginal cost analysis, it may be a misplaced interpretation of the estimated value of generating capacity. As an alternative, I have adopted the "Discounted Peaker Approach." This approach is appropriate for PREPA as it recognizes the future value of generation in an environment where demand is forecast to decline over the next planning horizon.

Q. Please describe the Discounted Peaker Approach.

A. The Discounted Peaker Approach recognizes that if a surplus of generation capacity exists, the value of that capacity will be depressed. The Discounted Peak methodology quantifies the differences in prices over time. The Discounted Peaker calculation can be stated as follows:

$$DP = PP \cdot \left(\frac{1}{(1+r)^n} \right)$$

where DP = Discounted Peak Price

PP = Peaker Price

r is the discount rate

n is the number of years until new capacity is required to serve new load (excluding capacity constructed for energy savings)

Q. **What assumption was adopted for the number of years required until capacity is required?**

A. We assumed that capacity would be required in 20 years, which is the end of the planning horizon. The assumption reflects an optimistic view of the capacity market and results in the MGCC being potentially overstated because of the truncated nature of the analysis. The results of the Discounted Peaker Approach are summarized in the table below:

Item	Variable / Component in Formula	Amount
Peaker Price: Marginal Generation Capacity costs Using the Peak Approach	PP	\$93.03
Annual Discount Rate	r	9.00%
Number of Years Until New Capacity is Required to Serve New Load	n	20
Discount Factor	$\left(\frac{1}{(1+r)^n}\right)$	17.84%
Discounted Peaker Marginal Cost	$DP = PP \cdot \left(\frac{1}{(1+r)^n}\right)$	\$ 16.60

Q. Have the results been adjusted for voltage level?

A. Yes. The table below provides the MGCC by voltage level. The results are stated with and without the reserve margin required for long-term planning purposes.

Voltage Level	Loss Factor	Marginal Generation Capacity Cost w/o Reserve Margin \$/kW-year (\$2017)	Marginal Generation Capacity Cost w/ Reserve Margin \$/kW-year (\$2017)
Generation	N/A	\$16.60	\$21.58
Transmission	3.00%	\$17.10	\$22.23
Primary	8.31%	\$17.98	\$23.37
Secondary	10.16%	\$18.29	\$23.77

B. Marginal (Generation) Energy Costs

Q. How were Marginal (Generation) Energy Costs ("MEC") estimated?

A. We adopted the analyses performed by Siemens in the IRP process. Annual and seasonal marginal energy costs appear in PREPA Ex. 9.04 attached to my testimony.

Q. Would you provide commentary on the results that are unique to Puerto Rico?

A. As noted above, a unique situation in Puerto Rico is that PREPA is an isolated system and cannot rely upon neighboring utilities to provide reliability support. Therefore, as previously stated, a higher reserve margin is required. Further, the level of spinning and non-spinning operating reserve is higher than a utility with a higher number of interconnections with neighboring utility, which increases the level of fuel burn or "Must-Run Generation". These factors are incorporated into the generation marginal cost analysis via use of the 30 percent generation reserve margin cited above and marginal energy costs that reflect the additional reserve requirements associated with operating as an island. The production cost analysis conducted by Siemens and reported herein includes adjustments for these additional reserves.

IV. <u>MARGINAL TRANSMISSION SERVICE COSTS</u>

Q. Please describe the economic nature of electric transmission systems?

A. Most electric transmission systems lines operate in a grid or network configuration; that is, lines are configured in a manner such that the loss of a single line does not result in an interruption of supply to load. The capability to provide continuous supply is commonly referred to as meeting a single or double contingency criteria, where a contingency is generally defined as a state under which there is loss of one or more transmission system elements or generating units. Transmission systems are designed in this manner to provide continuous supply to the system in case a specific component of the system fails or is removed from service for maintenance. In some instances, transmission lines operate radially, without contingency back-up. Radial transmission lines typically are lower voltage lines serving smaller load centers or located in remote areas on the system. Transmission networks have unusual cost characteristics in that the cost to provide an additional unit of output – the marginal costs – is often significantly less than the average cost of service due to the relatively large amount of investment required for non-load related purposes such as system reliability and security.

Q. **What implications does the network nature of electric transmission systems have on the type of investments required?**

A. Transmission investments are made for a variety of reasons. The categories on these investments include the following:

1. Investments that are required to ensure sufficient transmission capacity is available under normal and contingency conditions to reliably serve new load, commensurate with reliability criteria assigned to the interconnected generation and transmission system. The capability of the transmission network to withstand contingency events is essential if PREPA is to meet LOLH reliability targets.
2. Transmission investments intended to interconnect a generation unit to the transmission grid;
3. Alleviation of intertie constraints that connect distant markets and provide the opportunity for energy costs to be reduced (*i.e.*, arbitrage opportunities), which are expected to exceed the cost of the transmission interconnection;
4. Investments which are made in order to maintain or increase system reliability or security and are unrelated to increases in load; and,
5. Replacement of outdated, obsolete or worn-out equipment.

Q. How is Marginal Transmission Capacity Costs ("MGCC") defined?

A. The Marginal Transmission Capacity Cost is defined as the annual investment cost incurred when an additional kW of load is served by the transmission network. Therefore, it is necessary to isolate and remove project costs that are not associated with load growth in the Transmission System Expansion and Integrated Resource Plans.

Q. What time period is evaluated when estimating MGCC?

A. Because major load-driven transmission projects occur infrequently, it is necessary to examine an extended time period in order to produce reasonable estimates of transmission investments, commonly referred to as Long Run Marginal Cost After discussions with PREPA Staff, the time period of 2015/16 through 2024/25 was chosen to review transmission investments made to accommodate load growth. The total dollar investment is determined in 2017, and measured against the change in Annual Peak Coincident Electric Demand for the same time period. Coincident Peak Demand is used because load diversity is generally accommodated in an electric transmission system and the system must be capable of reliably serving load at the time of the electric system peak.

Q. What transmission investments does PREPA propose over the next ten years, and what portion of these investments will be made to serve additional load?

A. The total transmission investment portfolio for the next 10 years as of the marginal cost analysis is $833 million (2017), and is presented in PREPA Ex. 9.03. The exhibit lists and assigns each investment to one of the five investment categories described above.

The following table summarizes 10-year transmission capital investments for each category.

	Category	**10-Year Total**
1	Capacity for Load Growth	$0-
2	Interconnection of generation	$0-
3	Alleviation Transmission Constraints	$47,886,500
4	Reliability Improvements	$464,033,877
5	Replacement of Deteriorated or Obsolete Equipment	$321,301,020
	Total	**$833,221,397**

The portion of these investments assigned to new load (Category 1) is zero. This is an expected finding, as PREPA's Coincident Peak (CP) is projected to decline over the next 10 years. All investments outlined in PREPA's IRP are required to connect new generators, improve economic transfer capability and maintain reliability due to retiring generation in the north, or to replace deteriorated and obsolete equipment. Capital investments for reliability improvements include increases in line or substation capacity that are needed to meet PREPA single or double contingency criteria, but otherwise not required to serve new load. Several individual projects span multiple categories, such as replacement of obsolete equipment with equipment that also improves transmission system reliability. Where projects provide multiple benefits, the cost of the projects is allocated to each category based on the relative benefits resulting from the investment. For example, 40 percent of the 10-year cost of the single largest investment, Structural

Reconstruction of 115kV Lines at $59 million, is allocated to reliability, the remaining 60 percent to replacement. Because none of the investments cited above is required for growth in electrical demand, the marginal cost of transmission is zero.

V. <u>MARGINAL DISTRIBUTION COSTS</u>

Q. Please describe an electric distribution system.

A. An Electric Distribution System delivers power received from the Transmission System to the customer via equipment operating at primary and secondary voltages (provided that the customer is not receiving service at a Transmission Voltage). Marginal Distribution Costs are classified into two categories:

1. Marginal Distribution Capacity Costs. Marginal Distribution Capacity Costs ("MDCC") are defined as the cost to serve an additional KW of load on the distribution system;
2. Marginal Distribution Customer Costs. Marginal Distribution Customer Costs (MDCSC) are defined as the cost to serve another customer connected to the system regardless of the level of usage they receive from the utility.

Q. Please describe the approach used to estimate Marginal Distribution Capacity Costs.

A. Distribution investments for the time period 2016 through 2025 were prepared by PREPA in order to determine what fraction of those investments are associated with serving new load as opposed to replacement of existing infrastructure or to maintain or improve system reliability.

Our estimates of MDCC were prepared in a manner similar to that of the Marginal Transmission Capacity Cost Analysis. The investments associated with load growth over a period of several years were divided by the level of load growth as measured by the increase in new customers connected to the distribution system over the period 2016 to 2025. A key difference in the distribution analysis is that the denominator in the calculation is the Non-Coincident Peak of new customer demand on PREPA's distribution system as opposed to the Coincident Peak used to derive Marginal transmission costs. The Non-Coincident Peak is used because distribution systems are generally constructed as radial systems and, therefore, the peak load on individual lines and substations may not coincide with the system peak. Unlike transmission, individual lines and substations each must be capable of supplying their respective peak loads; that is, capacity requirements are set based on the non-coincident peak or NCP associated with each new asset added to serve new customers, whereas transmission capacity requirements are established based on the coincident peak of the interconnected network. Thus, load diversity among distribution lines and substations as measured by coincident peaks does not apply nor diminish the level of investment made by the utility.

Because of the expected decrease in load growth and the relatively small number of new customers (approximately 7 thousand) that will be connected to PREPA's distribution system over the next 10 years, Navigant estimated distribution NCP based on the PREPA design standards for new load. For new customers, PREPA design standards are based on a minimum residential connected demand of 5 kW. Hence, new distribution capacity must meet current design standards as compared to average demand of about 2 kW for existing customers. Because some of the new customers will be larger commercial load, Navigant increased the average kW connected demand for new customers to 8 kW. It excludes a customer cost component as new customers pay all costs associated with line extensions and equipment needed to connect the new load.

The following process was undertaken to estimate Marginal Distribution Capacity Costs:

1. Identification of Investments Associated With Load Growth – Similar to transmission, the first step in this analysis was to identify the portion of proposed distribution investments associated with load growth. This data was requested from PREPA and information was provided for the period 2015 through 2025.

2. However, as previously determined in the Transmission Capacity Cost Analysis, a negative change in Coincident Peak would lead to negative Marginal Distribution Capacity Costs. Therefore, for Marginal Distribution Capacity Costs, an alternate approach was used by measuring the change in total new customers connected to PREPA's distribution system from 2014 through 2025. Although the coincident system peak is projected to decline, an increase in new customers in a given area may result in investments in new distribution capacity in areas of the PREPA system where growth is expected to occur. The increase in NCP demand was estimated by multiplying the average NCP of 8kW per customer cited above by the number of new customers over the years 2014 through 2025. MDCC was then derived by dividing total load-related distribution capacity investments between 2014 and 2025 by the increase in connected NCP demand. Load-related

distribution investments include two years' actual amounts spent for 2014 and 2015, and forecast investments for 2016 through 2025.

Q. What distribution investments does PREPA propose over the next 10 years, and what portion of these investments will be made to serve additional load?

A. The total distribution investment portfolio for the next 10 years as of the marginal cost analysis is $818 million ($2017), and is presented in PREPA Ex. 9.02. The exhibit lists each distribution project or program investment to one of the five investment categories outlined in the section on transmission. The following table summarizes 10-year distribution capital investments for each category.

	Category	**10-Year Total**
1	Capacity for Load Growth (in distribution system elements)	
1a	Expansion	$40,066,380
1b	Improvement	$126,317,703
2	Interconnection of Generation	$0
3	Alleviation Transmission Constraints	$0
4	Reliability Improvements	$382,761,168
5	Replacement of Deteriorated or Obsolete Equipment	$268,727,163
	Total	**$817,872,413**

R2

The majority of PREPA's distribution capital forecast is to replace deteriorated, obsolete or inefficient equipment; or to construct new lines to improve reliability or operating flexibility. The amount of PREPA's 10-year distribution investment portfolio assigned to load growth (in distribution system elements) is $40.1 million. The $40.1 million is based on the portion of PREPA's distribution capital forecast that is for the expansion of its distribution lines and substations. Of this amount, about 50 percent or $20 million is reimbursed to PREPA in the form of contributions in aid of construction and therefore, excluded from the marginal cost calculation. The remainder of capacity investments related to load growth is $126.3 million, all of which is for improving the performance of the grid, and therefore excluded from Marginal Distribution Capacity Cost calculations. When the $20.1 million is combined with load-related distribution capacity investments of $8.3 million, net of customer contributions, total load-related capacity investments for years 2014 through 2025 is $28.4 million. The majority of expansion projects that are load growth-related are for new distribution substations, or for extension of overhead and underground feeders.

Q. What is the expected increase in total distribution NCP demand resulting from the connection of new customers?

A. The total number of new customers between 2014 and 2025 is projected at 6,795, which equates to an average annual growth of about 0.05 percent. When the 2014 average NCP of 8 kW per customer is applied, the increase in connected NCP demand is about 55.8 MW, or 4.7 MW on an annual basis.

Q. Please present MDCC based on the preceding analysis and values derived for incremental capacity, NCP demand and incremental O&M associated with load-related capital investments.

A. The following table presents marginal costs based on actual values for 2014 and 2015, and projected values for 2016 through 2025 stated in 2017 dollars. It includes distribution O&M associated with load-related capital projects as described earlier in my testimony.

Description	**Total**
2014-2015 Actual Load-Related Capital Investment	$8.3 MM
2016-2025 Forecast Load-Related Capital Investment	$20.1 MM
Total 12-Year Load-Related Investment	$28.4 MM
2014 – 2025 Increase in Connected NCP Demand	55.8 MW
Total 12-Year Load-Related Investment	$508.4/kW
Distribution Carrying Charge Rate	7.71%
Annual Marginal Distribution Capital Cost	$39.3/kW-Yr
Annual Incremental O&M	$0 /kW-Yr
Total Annual Marginal Distribution Capital Cost	**39.3/kW-Yr**

The result of the analysis produces an annual MDCC of $39.3/kW-Year. The annual value is then allocated on a seasonal basis during on-peak and off-peak hours, and combined with allocated Generation Marginal Capital Cost to produce Total Marginal Capital Cost that appears in PREPA Ex. 9.04.

VI. CONCLUSION

Q. Please summarize the results of your analysis.

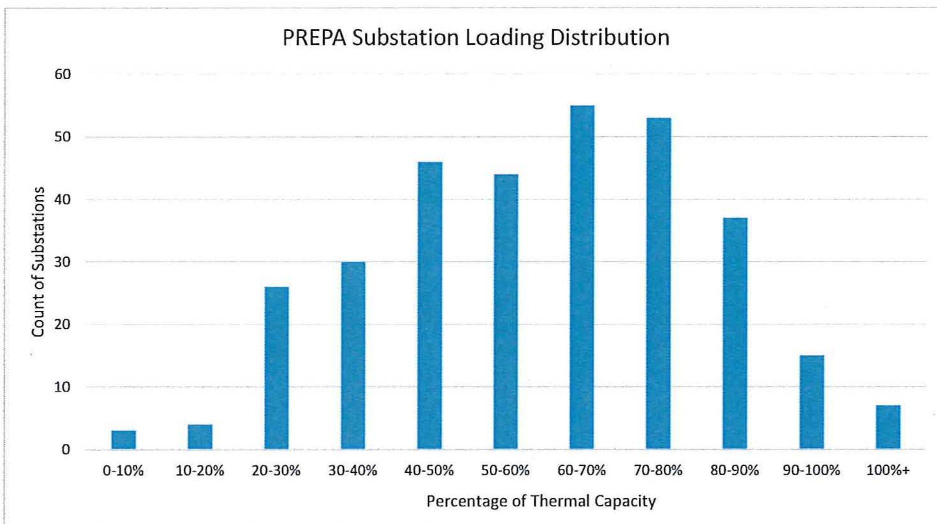
A. PREPA Ex. 9.04 summarizes the results of the study, which are stated in FY 2017 dollars. I have stated the results for transmission, distribution primary and distribution secondary in an unbundled basis with MGCC, MTCC, and MDCC stated in dollars per KW. The values that appear at the transmission, primary and secondary levels are adjusted based on PREPA loss factors outlined below. The allocation of capacity costs for both generation and distribution is based the percent hours within each time period. For generation, LOLH typically is used to allocate capacity cost. However, the use of LOLH would have resulted in the assignment of all generation capacity costs to the low season due to the maintenance scheduling algorithm in the Promod production cost model, so hours per period was deemed appropriate in lieu of LOLH. Because of this adjustment, it may be appropriate to apply annual values for marginal costs that appear in Ex. 9.04.

Loss Factors	On-Peak	Off-Peak	On-Peak	Off-Peak
Transmission	3.00%	3.00%	3.00%	3.00%
Primary	8.31%	8.31%	8.31%	8.31%
Secondary	10.16%	10.16%	10.16%	10.16%

Results also are presented on a KWH basis assuming an 80 percent load factor.

Q. Is there any additional information you believe it is important to convey regarding the marginal costs presented in your testimony?

A. Yes. The distribution component of MCOSS presented in PREPA Ex. 9.02 is based on a very small number of distribution facilities where local growth will cause substations or lines to become overloaded. The chart below confirms that less 10 substations of PREPA's 300+ substation are expected to experience overloads, some of which can be addressed by minor upgrades such as load transfers to adjacent substations with lower loads. Thus, unless load reduction initiatives or distributed generation, in sufficient quantities, are located at these few locations, actual avoided distribution costs would be zero. Further, many substation experience peak loadings during late evening hours. Thus, any solar-based distributed generation would not reduce peak distribution loads that would enable capacity deferral.



Q. Does this complete your direct testimony?

Yes.

No. CEPR- AP-2015-0001
PREPA Ex. 9.0

ATTESTATION

Affiant, Ralph Zarumba, being first duly sworn, states the following:

The prepared pre-filed Direct Testimony and the Schedules and Exhibits attached thereto and the Schedules I am sponsoring constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the pre-filed Direct Testimony if asked the questions propounded therein at the time of the filing. Affiant further states that, to the best of his knowledge, his statements made are true and correct.

Ralph Zarumba

Affidavit No. 3,582

Acknowledged and subscribed before me by Ralph Zarumba, of the personal circumstances above mentioned, in his capacity as a Director of Navigant Consulting, Inc., who is personally known to me or whom I have identified by means of his driver's license number from Illinois 2651-7345-9297, in San Juan, Puerto Rico, this 26 th day of May 2016.

Public Notary

JAIME J. ORTIZ RODRIGUEZ
PUERTO RICO
NOTARIO PUBLICO

EXENTO PAGO ARANCEL
LEY 47
4 DE JUNIO DE 1982