Resource Insight, Inc.

Cost Allocation, Revenue Allocation and Rate Design

An Overview and Review of the Proposals by the Puerto Rico Electric Power Authority

For the Puerto Rico Energy Commission

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November 17, 2016

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I. Introduction and Overview

A. Introduction

1. About the Author

I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts. I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I have been involved in utility regulation and planning since 1977. I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, conservation program design and cost recovery, the valuation of environmental externalities from energy production and use, performance-based ratemaking, allocation of costs of service among rate classes, and design of retail and wholesale rates, including rates for distributed generation.

I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-four states and six Canadian provinces, and two US Federal agencies. This testimony has included many reviews of utility cost allocation, rate design, and related issues.

My professional qualifications are attached as Appendix PLC-1.

B. Scope of this review

In this report, I review the approaches that PREPA has used in its proposed cost-of-service study and rate design. I have organized this review into six high-level groups of topics, which I discuss in Sections II to VII:

- PREPA's embedded cost-of-service study.
- Revenue allocation among classes.
- PREPA's marginal cost study.

- Subsidies and contributions in lieu of taxes.
- PREPA's proposed reconciling riders, which would true up several cost categories for historical over- or under-collections.
- Intra-class rate design.

I also comment on PREPA's performance in this proceeding.

My review of each issue includes the following issues:

- whether the proposed methodologies are appropriate,
- whether the supporting data are reliable,
- what improvements PREPA should make in its approach,
- what input data and assumptions need to be improved, and
- whether the issues can be sufficiently resolved in this case to guide decisions regarding revenue allocation and rate design.

In this report, I discuss PREPA's proposals and data in some detail. I will be referring to the following testimony (and the associated exhibits):

- PREPA Exhibit 4.0, Direct Testimony of Ralph Zarumba and Eugene Granovsky on revenue allocation and rate design.
- PREPA Exhibit 8.0, Direct Testimony of Ralph Zarumba and Eugene Granovsky on the cost-of-service study and cost allocation.
- PREPA Exhibit 9.0, Direct Testimony of Ralph Zarumba on marginal costs.
- PREPA Exhibit 12.0, Direct Testimony of Ralph Zarumba on provisional rates.
- PREPA Exhibit 15.0, Direct Supplemental Testimony of Ralph Zarumba and Eugene Granovsky.
- PREPA Exhibit 24.0, Rebuttal Testimony of Ralph Zarumba and Eugene Granovsky.

To minimize confusion among these six documents by Mr. Zarumba or Messrs. Zarumba and Granovsky, I will primarily refer to these testimonies by the exhibit numbers. Since the analyses were performed by Navigant Consulting (Mr. Zarumba's former employer and Mr. Granovsky's current employer), I sometimes refer to the analyses as being the work of Navigant.

To the extent that intervenor testimonies overlap with the issues I address, I have attempted to reference them as well.

I will also be referencing PREPA's responses to the discovery I drafted, which I will cite in the following format:

CEPR-PC-[set number]-[question number]

For example, the response to the 26th question in my first set of questions, including in Requirement of Information 4, will be referred to as CEPR-04-PC-01-026. Note that two sets of my questions, in ROI 13 and ROI 15, were numbered as set 11.

Less frequently, I will refer to the responses to questions in other sets, using the initials of the requesting individual.

C. The Ratemaking Process

1. Components of a Rate Case

Conceptually, a general rate proceeding starts with determination of the utility's **revenue requirement**.[1] The **cost-of-service study** then allocates the responsibility for those revenue requirements among the tariff classes, based on a large number of judgments and estimates. Informed but not bound by the cost-of-service study, and taking into account the magnitude of the revenue requirement, the effect of increases on particular tariff classes, gradualism, and other policy considerations, the regulator determines the **revenue allocation**, which sets the revenue to be collected from each class. Finally, a **rate design** is developed for each class, setting charges—a fixed charge per month, a charge per kWh, perhaps charges for maximum hourly load or other factors—that are expected to collect from the customers in each class the revenue allocated to that class.

Throughout this process, the regulator may consider various special **cost-recovery mechanisms**, such as riders (which may update costs for new data and/or reconcile past revenue and costs) for the costs of fuel, purchased power, and DSM programs and updates to reflect changes in financing costs, investments, expenses, revenues and/or sales that occur during the period of time when approved rates are in effect. For each rate component, the regulator must determine whether it should be reflected in one of these special mechanisms, how much (if any) of the factor should be in base rates (the portions consumer bills that remain fixed, outside of the targeted riders), how the mechanism should be structured, how the rate adjustments should be supervised and reviewed, and how any costs flowing through the mechanism should be allocated to classes and reflected in rates. Consideration of cost-recovery mechanisms reflects and affects the revenue requirement, cost-of-service allocation, revenue allocation, and rate design, and thus is not really a separable step in the rate case.

In the actual process of most rate cases, all four-plus parts of the proceeding occur simultaneously. Some jurisdictions instead divide these steps, setting the revenue

[1] This step requires resolution of many issues complex issues, but it is a prerequisite to the processes I discuss in this report.

requirement in one proceeding, while considering alternative mechanisms and determining the rules for cost allocation, revenue allocation and rate design in one or more independent cases.

In the sections below, I review the issues that arise in each of the steps of cost allocation, revenue allocation, rate design and some aspects of the riders. Other Commission experts will be addressing revenue requirements and cost-recovery mechanisms.

I discuss the following three items in Sections II, III and VII.

1. **Cost allocation** is the determination of what costs are equitably allocable to each rate class. Cost allocation is accomplished through a "cost-of-service study" (COSS) that breaks costs down in great detail and attempts to identify an appropriate allocation for each cost category.[2] The Commission need not approve, or even review, a cost-of-service study in any particular rate proceeding. Some regulators review COSSs in every rate case, others review a COSS once a decade. Some regulators select a particular COSS methodology to guide their decisions about rates; others consider several methodologies, without explicitly accepting any one method.

2. **Revenue allocation** is the determination of how responsibility for paying the utility's revenue requirement will be divided among the classes. This is a decision that the regulator must make in every ratesetting proceeding. The revenue allocation may be based on a simple rule, such as the equal ¢/kWh allocation in the transition charge and in the provisional rates, or an equal percentage increase for all classes. Or it can be much more complicated, reflecting a cost-of-service study and other considerations.

3. **Rate design** is the determination of how the allocated revenue will be collected from each class, through monthly customer charges, energy charges and demand charges, in their many variations.

2. *Standard Principles of Ratemaking*

One of the industry standard references for ratemaking concepts, *Principles of Public Utiliity Rates* by James C. Bonbright (1961), lists the following criteria for a "desirable

[2] In the confusing world of utility regulatory terminology, "cost-of-service" is also sometimes applied to the determination of the utility's expenses in the revenue requirements portion of the rate case.

rate structure," a term that he uses to cover rate design, revenue allocation, and some parts of setting the revenue requirement:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements ….
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company:
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity…).

Criteria 1 and 2, while important, tend to be non-controversial: rate designs should be understood by customers and easy to administer. The application of demand charges to small customers and some complex time-varying rates raise questions regarding customer understanding.

Criteria 3 and 4 in this list are addressed in the determination of the revenue requirements and the updating of the revenue requirement to reflect changes in costs and sales, and are beyond the scope of my report.

Criterion 5, while desirable, is largely rendered impractical, due to the combination of PREPA's precarious financial position and the magnitude and volatility of its fuel costs—a situation Professor Bonbright could hardly have anticipated in 1961.

Criteria 6 and 7 require that the revenue allocation among classes be "fair" and avoid "undue discrimination." The resulting standard is far from a requirement of precise revenue allocation, since "fair" and "undue" are subjective terms.

Criterion 7 can also be read as requiring that the rate design not introduce "undue discrimination" within a tariff. Criterion 8 focuses the rate-design process on providing efficient price signals, which can be in conflict with other criteria.

3. Classes, Tariffs and Tariff Codes

PREPA typically speaks about the following customer classes:

- Residential,
- Commercial,

- Industrial,
- Agriculture,
- Public Lighting, and
- Other Public Authorities (which PREPA sometimes rolls into the commercial class for presentation purposes).

Within each of these broad classes, customers are assigned to different tariffs, depending the customers' characteristics. PREPA Exhibit 4.0 lists 17 tariffs:

- Tariff GRS (general residential)
- Tariff RH3 (municipal public housing)
- Tariff LRS (low-income residential)
- Tariff RFR (Public Housing Administration tenants)
- Tariff GSS (secondary general service)
- Tariff GSP (primary general service)
- Tariff TOU-P (time-of-use primary)
- Tariff GST (transmission general service)
- Tariff LIS (large industrial)
- Tariff TOU-T (time-of-use transmission)
- Tariff SBS (standby service)
- Tariff GAS (agriculture)
- Tariff PPBB (independent power producer)
- Tariff PLG (public lighting)
- Tariff USSL (some unmetered loads)[3]
- Tariff CATV

[3] Other unmetered loads, mostly for light, are sometimes treated as part of public lighting as sometimes as separate tariffs.

- Tariff LP-13 (sports-field lighting)

Many of these tariffs serve only one customer class, but GSS, GSP, GST and TOU-P all serve customers in the commercial, industrial and/or public classes.

PREPA (like many utilities) further divides most tariffs into several "tariff codes," reflecting such distinctions as:

- The size (measured in various ways) of customers on the RH3, RFR, LRS, TOU and LIS tariffs.
- Whether GRS customers are subject to the discount for students, the handicapped and the elderly.
- Whether the GSS, GSP, GST and TOU-P customers are commercial, industrial and/or public authorities.
- Whether the customer uses net metering or storage air conditioning.
- Whether the customer takes standby service, or has a rate discount for new or expanded loads.
- The end-uses served by public lighting and unmetered loads.

PREPA lists 71 tariff codes, of which 47 have customers. Thus, we are faced with five or six classes, 17 tariffs, and 47 active tariff codes.

D. The Utility System

An electric utility's assets and operations can typically be disaggregated into four functions:

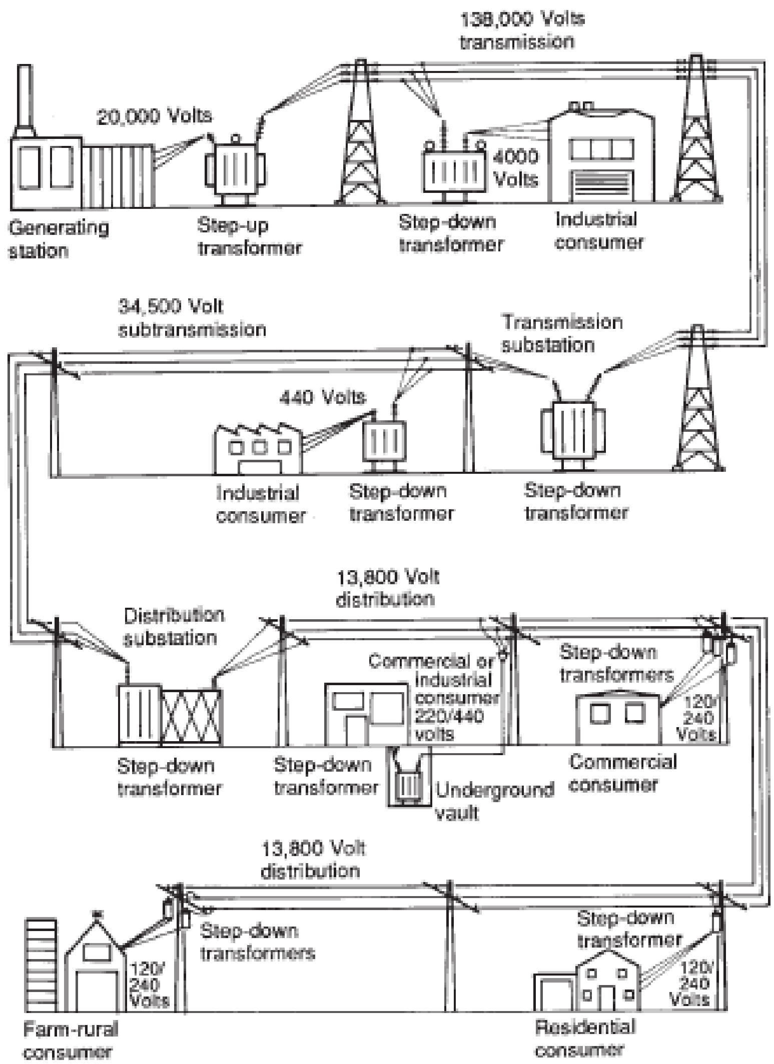
- generation (the production of electricity),
- transmission (the transportation of electricity over long distances at high voltages, at voltages over 30,000 volts, or 30kV),
- distribution (the transportation of electricity from the transmission system to the customers, at voltages under 30 kV), and
- customer service or retail functions (billing and otherwise interacting with customers).

In addition, there are overhead costs for general plant and services (e.g., offices, executives, finance, legal, personnel) that serve most or all of the functions, to varying extent.

Most utilities have some customers served directly from higher-voltage transmission lines (often defined as over 100 kV), some from lower-voltage (roughly 30 kV to 60 kV) subtransmission lines, and most from distribution lines (under 30 kV). Almost all electricity is actually used at distribution voltages, so customers served at transmission voltage must have facilities to transform the power down to a useful voltage.

Figure 1 illustrates the basic structure of a typical electric utility.[4]

Figure 1: Conceptual Diagram of an Electric Utility System



From: http://electricalengineeringdesigns.blogspot.com/2012/05/transmission-and-distribution-system.html

[4] The figure shows a single residential customer served by a single line transformer; more typically, a transformer would serve several customers.

1. Generation

PREPA's power supply comes from numerous generating units with different characteristics, which can be roughly organized into five groups:

- Steam-electric units that burn fuel in a boiler to produce steam to turn a turbine, which turns an electric generator. The steam must be condensed (usually using water) to keep the process operating. PREPA has 13 steam units at Aquirre, Costa Sur, Palo Seco, and San Juan, which burn the least expensive common grade of fuel oil, #6 residual. Costa Sur can also burn gas provided by the nearby EcoElectrica facility.
- Gas turbines (also called combustion turbines), which use hot gases from combustion of liquid or gaseous fuel to turn a turbine, which turns an electric generator. Gas turbines have been significantly less expensive to build than steam units (for the same construction year), but have usually been less efficient. Since the 1980s, the efficiency of gas turbines has been comparable to that of steam units, due to technological improvements, and have crowded out steam units, where both plants would burn the same fuel. Due to contact between the combustion gas and the turbine blades, gas turbines require high-quality clean fuels, usually natural gas or high-quality #2 distillate (diesel) fuel oil. Since diesel fuel is much more expensive than #6 residual, the cost of energy from PREPA's steam plants continue to be lower than from its gas turbines, all of which burn diesel oil. Gas turbines tend to be more flexible than steam plants, especially large steam plants, many of which tend to start up and shut down slowly. PREPA owns three old inefficient gas turbines at Cambalache, four new efficient gas turbines at Mayaguez, and 18 gas turbines distributed around the system.
- Combined-cycle units, which combine one or more gas turbines with a heat-recovery boiler fired by the gas-turbine exhaust. The boiler produces steam, much like a conventional steam plant. Each unit of fuel is used twice, in the gas turbine and in the boiler, significantly increasing the electric energy produced per unit of fuel. Combined-cycle units tend to be more expensive to build and maintain than gas turbines. Combined-cycle units require the same high quality of fuel as do the gas turbines. PREPA owns two old, inefficient combined-cycle units at Aguirre and two modern (and much more efficient) combined-cycle units.
- Power purchases from two independent power producers (IPPs): a steam-electric coal-fired power plant owned by AES and a combined-cycle unit owned by

EcoElectrica, the latter powered with liquified natural gas (LNG).[5] These types of plants have high fixed costs—especially due to AES's complex coal boiler and its maintenance and the construction and operation of the LNG terminal at EcoElectrica—but low fuel costs per kWh.

- Various renewable resources, including 60 MW of PREPA-owned small hydroelectric plants (in which water turns a turbine), plus some purchases from wind power plants (in which moving air turns a turbine) and from solar plants (which produce energy from sunlight).

PREPA plans to add small combined-cycle units, starting with at least one unit (and possibly up to three) at San Juan in 2020. Other potential generation projects (which would require Commission approval) include replacing the gas turbines at the Aguirre combined-cycle units with larger, more efficient turbines; building the Aguirre Offshore Gas Platform (AOGP) to provide natural gas to fuel existing and replacement generation at Aguirre; and potentially installing addition combined-cycle units. PREPA load is not expected to grow in the next several years; the generation additions are intended to replace retiring steam units, to improve fuel efficiency, and (if AOGP goes forward) reduce fuel costs and allow the old Aguirre steam units to operate at high load factors without violating air-quality rules.

PREPA may retire additional units, or relegate them to limited use, reducing O&M and environmental-compliance costs, depending on load levels and other factors.

2. Transmission

Figure 2 shows the high-voltage portion of the PREPA transmission system, comprising 230 circuit-miles of 230 kV lines and 725 circuit-miles of 115 kV lines.[6] This map, created by PREPA, does not show an additional 1,376 miles of 38 kV lines, probably because they would make the map too cluttered.[7]

Utilities use a variety of transmission voltages because a higher voltage allows more power to be delivered through the same size wires without excessive losses, overheating the conductor, or suffering excessive drop in the operating voltage over the length of the line. Higher voltages require taller towers to separate the power lines from the ground

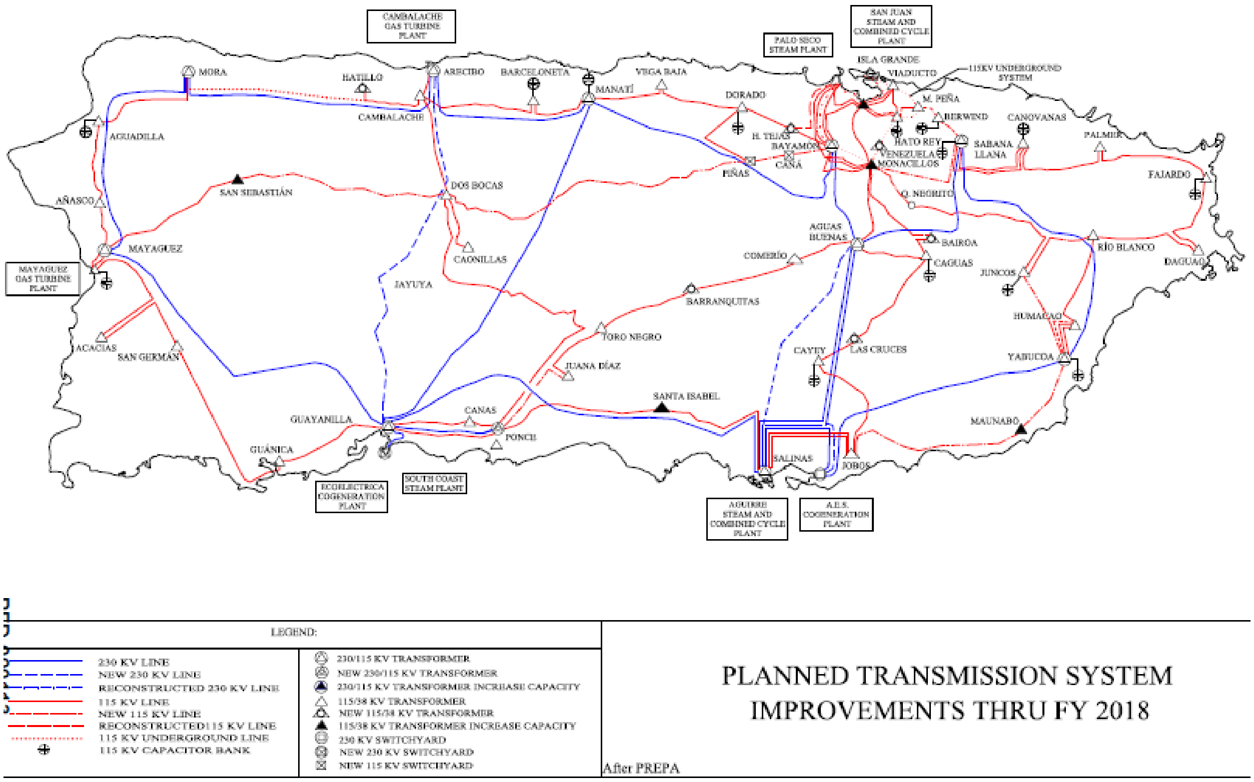
[5] These two plants are usually called "cogenerators" in Puerto Rico, referring to the original operation of the plants to produce both electricity and useful heat.

[6] A circuit-mile of transmission is one mile of line, consisting of three powered conductors and sometimes a neutral or ground line. A single transmission corridor, and even a single transmission tower, can carry multiple circuits.

[7] The circuit miles of transmission lines are from PREPA's 2014 Consulting Engineers Report, p. 3.

and other objects, and better insulation on underground cables, but may still be less expensive than running multiple conductors at lower voltages.

Figure 2: PREPA's Transmission System, as Planned in 2013



Source: Fortieth Annual Report on the Electric Property of the Puerto Rico Electric Power Authority, June 2013

Small percentages of the 115 kV and 38 kV transmission lines are underground or submarine cable, principally in dense urban areas. The vast majority of transmission lines are overhead, supported on steel towers or on poles of wood, concrete or other materials.

a. Network Lines

The high-voltage transmission network basically loops around the island, with additional lines connecting North and South, so power from the major generation stations can reach the main load centers. The high-voltage transmission connects to some major customers, to substations that step the voltage down to 38 kV subtransmission, and to substations that step the voltage down to distribution at 4.2 kV, 8.3 kV, or 13.2 kV.

In any utility system, some of this backbone transmission will be needed so that loads in any particular portion of the service territory can be served, even if the local generation is unavailable or uneconomic to operate. The low reliability of much of PREPA's generation, and the location of a disproportionate share of the most economic and reliable existing and planned generation on the South coast, makes this backbone transmission even more important for Puerto Rico.

The 38 kV subtransmission lines complement the high-voltage transmission, serving the same types of direct customers and substations.[8] Where load is relatively low, the utility can serve it with the less-expensive subtransmission; where load is high, the utility may need to upgrade to the more-expensive high-voltage equipment. A new energy-intensive factory that is willing to deal with stepping down transmission voltages to its end-use voltages will usually be able to take power in a range of voltages, depending on what voltage is available at its site.

A small number of customers (mostly on the GST tariff) are served directly from the transmission lines. Each of those customers must provide its own substation, to transform the power down to a usable voltage.

Some transmission assets may be part of and required for generation connection. For example, PREPA names several switchyards that are required primarily to connect one or more generators to the transmission system (CEPR-PC-02-026 (Confidential)).

To summarize, the uses of transmission equipment include the following:

- creating a network that can move power around from many sources to many delivery points,
- connecting radial load (substations and transmission customers) to that network, and
- connecting generation to the network.

b. Substations

Figure 2 also shows as various kinds of triangles the locations of the some of the 45 transmission substations that connect the generators to the transmission system and the various transmission voltages to one another, and house equipment for switching and controlling transmission lines. Most substations are centered on large transformers to convert power from one voltage to another.

c. Generation connection

Some of the transmission lines and substations are required to interconnect generators to the transmission system. These facilities are commonly treated as part of the generation function.

3. *Distribution*

As noted above, the distribution substations and lines are almost entirely incremental to the transmission system, and are required only for customers who take service at

[8] The 38 kV lines serve distribution substations that step down power to a feeders at 4.2 kV, 8.4 kV or 13.2 kV, just like the 115 kV lines, and also a few substations that step down to 4.8 kV or 7.2 kV.

distribution voltages. Very few of those customers would be able to take power at transmission voltages, even if a transmission line ran by their property.

a. Substations

The distribution system is fed power mostly from the transmission system, through distribution substations, although some power may be delivered to some distribution lines directly from small generators, such as PREPA's hydro plants and distributed renewables. These are smaller versions of the transmission substations.[9]

b. Primary feeders and branches

From each substation, one or more distribution feeders at 4.2 kV, 8.4 kV or 13.2 kV run up to a few miles, typically along roadways. These are mostly on wooden utility poles, shared with telephone and cable services. Several percent of the circuit miles of transmission feeders are underground. Again, a single pole or underground route may carry multiple circuits.

Each feeder may branch off to pick up customers on side streets. While distribution feeders leaving the substations are usually three-phase, like the transmission lines, branches that do not carry much load may be built as single-phase lines, with just one power conductor.

c. Line transformers

Some customers (mostly on the GSP tariff) take power directly at the primary voltage (4.2 kV, 8.4 kV or 13.2 kV) and transform it down to a secondary voltage (less than 600 V). All residential and most commercial customers (mostly on the GSS rate) take service from PREPA at secondary voltages (120, 208, 240, or 440 V). For that purpose, PREPA must provide line transformers, which are the large cylinders on some utility poles (for overhead distribution) and the rectangular metal boxes in front of buildings with underground distribution.

In urban and suburban settings, a typical transformer will serve several residential customers or small businesses, in one building (e.g., a large apartment building) or several. A single large customer on the GSS rate may be served by one or more dedicated transformers, and in very rural areas, even a relatively small customer may be so far away from neighbors as to require a separate transformer.

d. Secondary

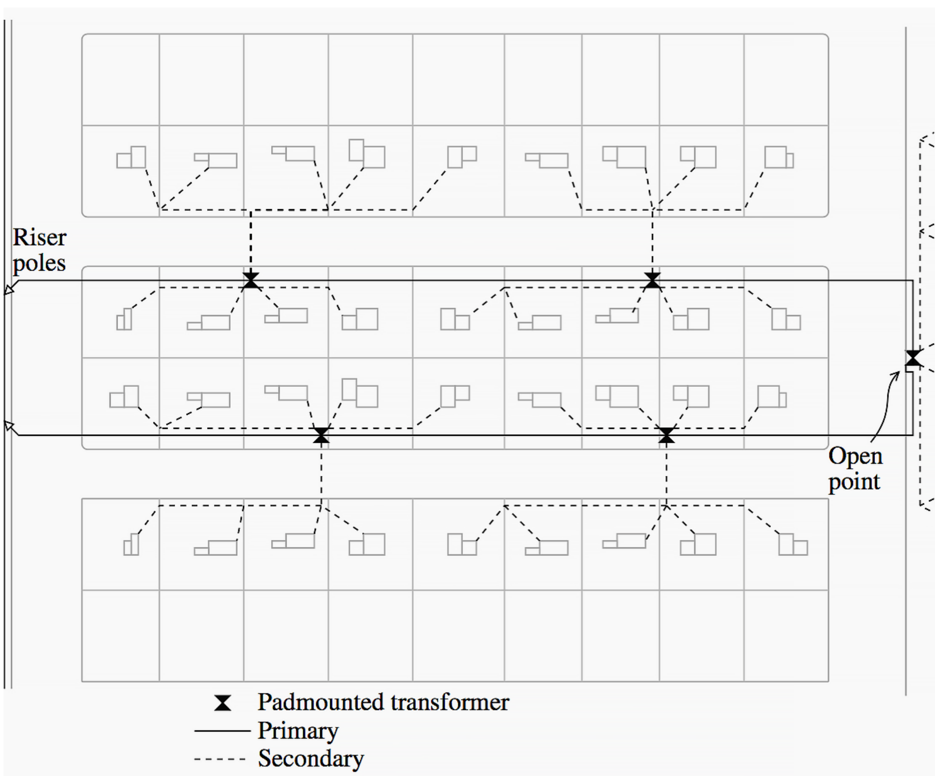
Some secondary-voltage customers will be served directly by a service drop from the transformer to their building. Other customers further from the up the road will be fed

[9] In some cases, a higher-voltage distribution line (e.g., 13.2 kV) may power a lower voltage line (e.g., 4.2 kV) through a substation. I have not identified that configuration in Puerto Rico.

from a secondary distribution line, attached to the same poles as the primary feeder, but lower down.[10]

Figure 3 illustrates these arrangements. In this example, each transformer serves two houses directly with service drops, and also feeds secondary lines from which service drops run to two or three other houses on the same side of the street, as well as four or five houses across the street. The illustration is for an underground system. The basic layout of an overhead system would be similar, but since it is easier to string overhead service drops across the street than to dig underground lines under the street, service drops might run directly from an overhead transformer to one or two houses across the street, and the secondary might just run on the transformers' side of the street, with service drops running across the street to additional customers.[11]

Figure 3: Line Transformers, Secondary Lines and Service Drops

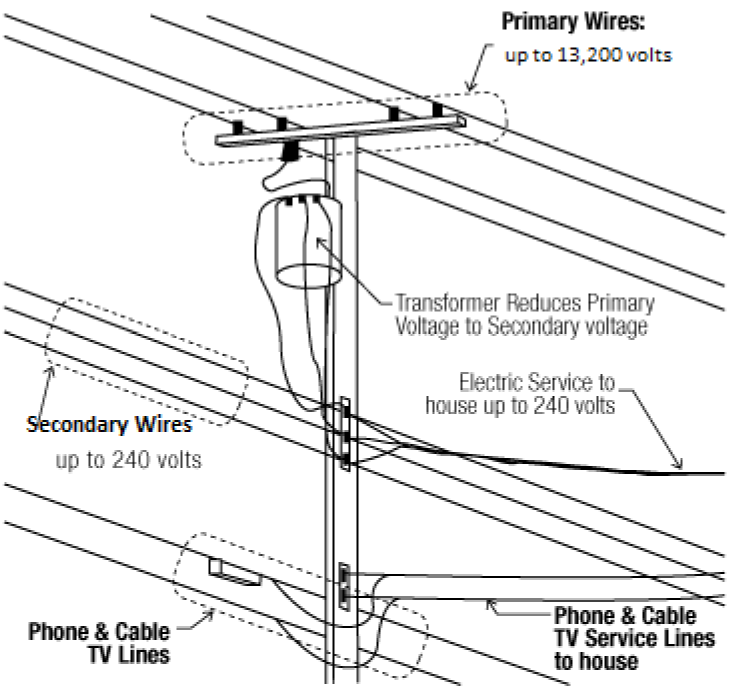


[10] The lower secondary voltage does not need to be separated from the ground quite as carefully as the higher primary voltage.

[11] The "riser poles" on the left are where the overhead primary lines run down the poles and go underground to serve this neighborhood.

Figure 4 illustrates a typical overhead distribution pole, showing the primary lines, a transformer, an electric service to one home, and secondary running in both directions to serve multiple homes.

Figure 4: Illustration of Secondary Distribution Layout



e. Service Drops

The final step in the delivery of power from the utility to the customer is the service line or service drop, from the common distribution facilities is the public way to the customer's meter.[12] That line may be overhead or underground; even where the distribution service is overhead, customers may opt for an underground service drop, out of concerns for aesthetics or reliability; underground lines are not vulnerable to damage from wind and falling tree limbs.

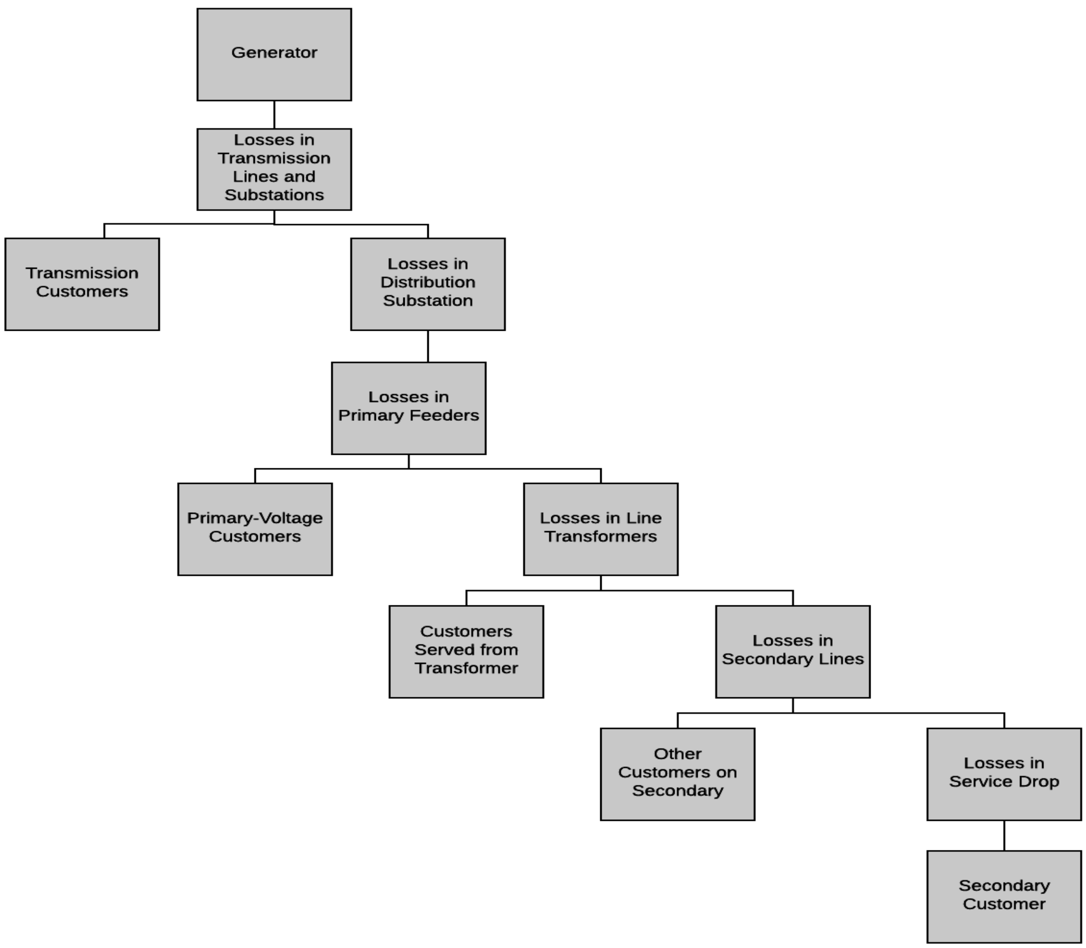
For primary-voltage customers, the service drop is a line at the primary voltage, attached to one or more phases of primary feeder. For secondary customers, the service drop may run from the transformer to the customer, or from some convenient point along the secondary lines.

[12] Since overhead service lines often slope down from their connection on the utility pole to the attachment point on the customer's building, they tend to literally drop the service down to the customer.

4. Line losses

The losses in conductors (including transmission and distribution lines and in transformers) varies with the square of the quantity of power flowing through the wire, so a 1% reduction in load reduces losses by about 2%.[13] The levels of conductor losses from the generators to a distributed generation customer at secondary voltage (such as a residential customer) are illustrated in Figure 5.

Figure 5: Line-Loss Schematic



Reducing a customer's load reduces the losses in the service drop from the street to the customer, the secondary line (if any) serving that customer, the line transformers, the distribution feeder, the distribution substation, and probably several transmission lines and transmission substations. Rates are usually designed to collect average line losses

[13] A 1% load reduction reduces losses to 0.99 × 0.99 = 0.98 times the original value.

from customers, so cost savings from any reduction in line losses above the average level flow to all customers.

E. Cost Drivers

Utilities make numerous decisions that cause them to incur costs that become part of the revenue requirement. Some of those decisions were made decades ago, as the utility made investments based on conditions or forecasts at that time. Some of the decisions are made every day, as the utility dispatches power plants or replaces overloaded equipment.

Many of the decisions that determine the utility's revenue requirement—such as the historical decisions to build particular power plants in particular locations—result from complex processes, involving past expectations and many practical complications and tradeoffs. For cost-allocation and rate-design purposes, it is important to identify relatively simple metrics (energy use in various periods, demand at various times, number of customers of various types) that can be associated with particular classes or customers. Effective cost allocation and rate design require the identification of these central cost-causation factors, or cost drivers.

1. Generation costs

a. Fixed and variable costs

Generation costs consist of costs that are variable in the short term and those that are fixed over the course of a year or more. The variable costs for utilities with fossil-fired generation (like PREPA) are mostly fuel costs, followed by portions of power purchases that vary with energy taken. In addition, some O&M costs are usually considered variable: some consumable materials (especially for pollution-control equipment), along with costs of replacements (such as of lubricants and filters) and overhauls that are required after a specified amount of output, equivalent full-load hours of operation, or similar measures.[14] In the IRP, PREPA estimated variable O&M of $3/MWh for small new combined-cycle units, $8/MWh for reciprocating engines, and $6.8/MWh for small new combustion turbines (IRP Tables 2-5 to 2-9).

Some utilities also treat as variable costs certain capital replacements that are driven by wear and tear, rather than the passage of time.[15]

Generation costs fixed in the short term include the existing investment, most operating costs and capital additions already required by the conditions of the plants. All of these

[14] These costs are comparable to the costs of automotive oil changes and routine services that are driven by miles driven.

[15] These costs are comparable to tire replacements that are driven by wear and tear closely correlated with miles driven.

costs are variable in the long term, as loads determine whether new generators are added, and whether existing generators are rehabilitated and kept on line.

In many cases, utilities that treat some O&M and interim capital additions as variable for particular purposes (such as rate design or evaluation of potential generation resources) treat all such costs as fixed for cost-allocation purposes, for simplicity. Cost-of-service studies are normally driven primarily by accounting data that does not readily differentiate variable from fixed O&M and capital additions.

b. Capacity requirements

The amount of capacity (in megawatts) required by an isolated utility, like PREPA, determines whether the utility needs to add new plants, delay retirement of existing units, and keep plants in full operation (rather than relegating them to limited use).

PREPA, like most utilities, determines its capacity requirement by determining what amount of existing and new capacity will provide acceptable reliability, measured by such statistical parameters as the mathematical expected value of the number of hours in which it cannot serve load, or of the amount of customer energy it will not be able to serve in a year, due to insufficient available generation.[16] Those expected values are computed from models that simulate the scheduling of generation maintenance and the random timing of forced outages, for many potential combinations of outages and load levels.

The most important parameters in determining the required reserves, usually expressed as the reserve margin (capacity ÷ peak load – 1) are:

- High-load hours, including the annual and weekly peaks and the number of other hours with loads close to the peaks. The system must have enough capacity to endure multiple outages at the high-load hours. The near-peak hours matter because the probability of any given combination of outages coinciding with the peak hour is very low, but if there are hundreds of hours in which that combination of outages would result in a supply shortage, the contribution to expected loss of load would be much larger. PREPA's load varies over the course of the typical week day, but about 14 hours a day are within 200 MW (or the loss of any of a dozen PREPA units), so many hours must contribute to PREPA's risk of losing load.
- Maintenance requirements. Utilities attempt to schedule generator maintenance in months with loads lower than the peak. For PREPA, that would be months in the winter and spring. Utilities with (1) modest maintenance requirements and (2) several months with loads reliably well below those in the peak months can schedule all

[16] These measures are referred to as the loss-of-load hours (LOLH) and loss-of-energy expectation (LOEE),

routine maintenance in the off-peak months, while leaving enough active capacity to avoid any significant risk of a capacity shortage in those months. PREPA is not in that situation. Peaks in the lowest-load months are only about 300 or 400 MW lower than the annual peaks, so scheduling even one large plant for maintenance in a low-load makes its shortage risk comparable to the peak month. Mr. Zarumba explained that "the maintenance scheduling algorithm in the Promod production cost Model" would result in all the loss-of-load occurring in the "low season" (Exhibit 9.0, p. 20). As a result, high loads in any month (or perhaps any week) contribute to the need for installed capacity.

- Forced outage rates. All generation units experience some mechanical failures. The higher the frequency of forced outages, the more likely it is that a relatively high-load hour will coincide with outages at multiple units, eliminating PREPA's available reserve and resulting in the loss of load.
- Unit sizes. If all of PREPA's units were very small (say 20 MW), the random outages would be spread quite evenly through the year. But PREPA has four units over 400 MW; an outage at one of those units removes supply equal to about 13% of PREPA's annual peak. This is one reason that PREPA must maintain very high reserve margins of about 70% or 2,000 MW.[17] In contrast, Nova Scotia Power (which has an annual peak load about 65% as high as PREPA's) limits generators to 170 MW and finds a reserve margin of 20% to be adequate.[18]

Some of the factors discussed above have little effect on the types of load that increase required capacity and reserve levels, but high loads in all months contribute to PREPA's capacity requirement, due to PREPA's low seasonal load variation, high outage and maintenance requirements. In addition, PREPA's long daily period of high loads mean that many weekday hours (and some weekend hours) in each month will contribute to capacity requirements.

c. Cost of capacity

While PREPA's required capacity (measured in megawatts) is determined by demands in a relatively small number of hours with high loads, along with the characteristics of the power plants, the cost of capacity (measured in dollars power megawatt) is in large part determined by energy requirements. The least expensive plants to build and maintain tend to have low fuel efficiency (*i.e.*, requiring more fuel to produce a kWh of electricity)

[17] Mr. Zarumba asserts that "PREPA's 'firm' reserve margin for generation resources effectively is about 30 percent." (Exhibit 9.0, page 4) His definition of a firm reserve margin is the reserve margin minus the average amount of capacity that is unavailable at any time.

[18] NS Power also has a small interconnection with a neighboring utility, larger seasonal load variation than PREPA, and lower forced-outage rates.

and require premium fuels, while steam plants and combined-cycle units tend to be more expensive to build, but less expensive to run for many hours in a day or year. For PREPA, simple-cycle gas turbines would be suitable for meeting a few peak loads, but steam plants have historically had higher efficiency and used less-expensive fuel, while more recently combined-cycle units have used the same fuel as gas turbines, but more efficiently. Coal and LNG-fired combined-cycle plants (like AES and EcoElectrica have even higher fixed costs, but still lower fuel costs than PREPA's oil-fired steam and combined-cycle plants. The decision to build (or contract with) more-expensive capacity is driven by energy requirements, not peak loads.

2. Transmission costs

a. Lines

The costs of transmission lines depend on the length of the lines and the amount of power they need to carry. Carrying more power requires larger conductors, multiple conductors, and/or higher voltages, all of which increase costs.

If each load center in a utility's territory had about the amount of generation required to meet its peak load, and the power plants were similar, so the utility had no interest in exporting power from one area to another, the transmission system would exist primarily to allow each load center to draw on the others for backup supply when local generation was unavailable. In real utility systems, power plants are often distributed very differently from load, with large centralized plants built to capture economies of scale, often in areas far from major load centers. Generation may be sited remotely from load for environmental reasons, to facilitate access to fuel, to minimize land costs and land-use conflict. Generation plants also tend to vary considerably in fuel cost, efficiency and flexibility; allowing the utility to use the least-cost mix of generation at all load levels may require additional transmission.

While separating all the causes of the structure of an existing transmission system can be difficult (especially for a utility whose distribution of load and generation has changed over the decades), decisions about the nature and location of generation facilities can have important effects on the costs of the transmission system.

PREPA has chosen to locate the baseload generation plants (EcoElectrica and AES) on the south coast. The accident of the availability of natural gas from EcoElectrica has resulted in the conversion of Costa Sur, and the relative ease of siting a gas port in the south may lead to gas conversion of Aguirre. Combined with the retirement of generation in the north, the expected increase in relatively low-cost energy in the south has prompted PREPA to propose additional transmission to deliver power from the southern generation plants located to San Juan.

Energy load over the course of many hours also affects the sizing and cost of transmission. Underground transmission is particularly sensitive to the build-up of heat around the lines, so the length of peak loads and the extent to which loads decline from the peak period to the off-peak period affects the sizing of underground lines. An underground line may be able to carry twice as much load for a 15-minute peak after a day of low loads as for an eight-hour peak with a high daily load factor. To reduce losses and the build-up of heat, utilities must install larger cables, or more cables, than they would to meet shorter loads.

The capacity of overhead lines is often limited by the sagging caused by thermal expansion of the conductors, which also occurs more readily with summer peak conditions of high air temperatures, light winds and strong sunlight. Overheating and sagging also reduce the operating life of the conductors.

b. Substations

The costs of substations, including the power transformers around which they are centered, are determined by both peak loads and energy use.

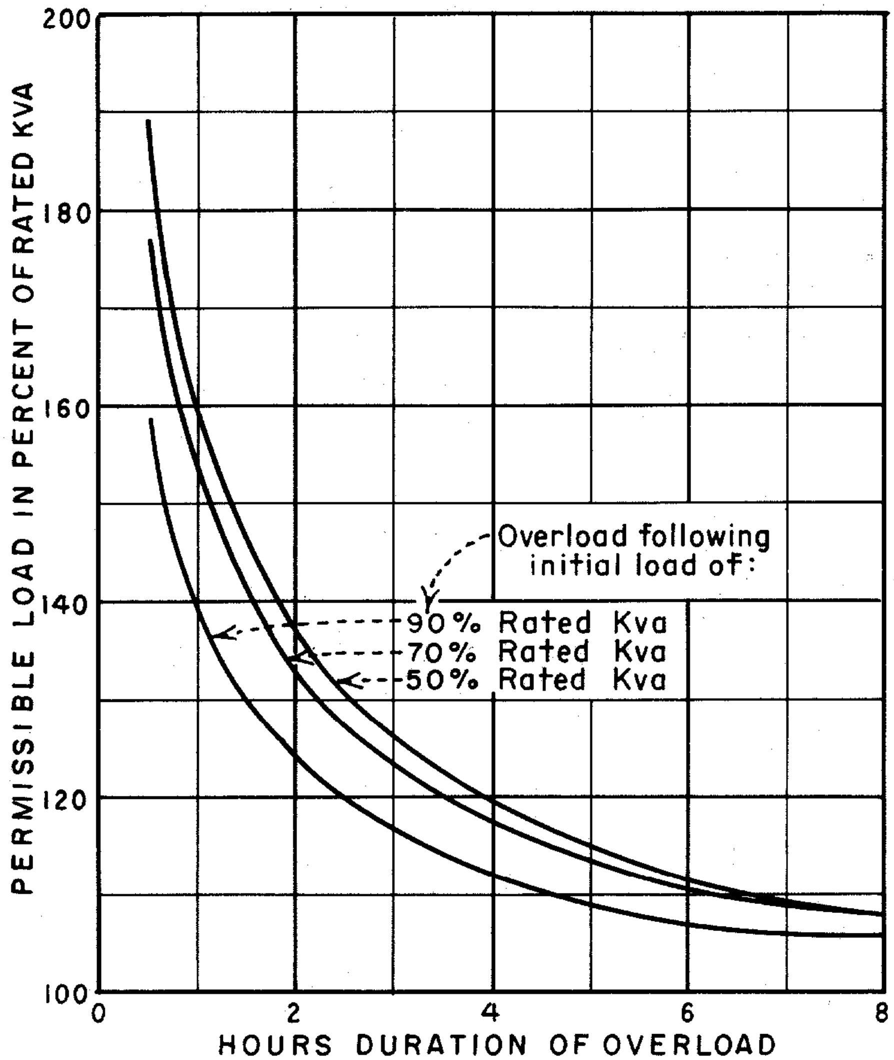
The capacity of a transformer is limited by the build-up of heat created by electric energy losses in the equipment. Every time a transformer approaches or exceeds its rated capacity (a common occurrence, since transformers can typically operate well above their rated capacity for short periods of time), its internal insulation deteriorates and it loses a portion of its useful life.

Figure 6 illustrates the effect of the length of the peak load, and the load in preceding hours, on the load that a transformer can carry without losing operating life.[19] The initial load in Figure 6 is defined as the maximum of the average load in the preceding two hours or 24 hours. A transformer that was loaded to 50% of its rating in the afternoon can endure an overload of 190% for 30 minutes or 160% for an hour. If the afternoon load were 90% of the transformer rating, it could only carry 160% of its rated load for 30 minutes or 140% for an hour.[20]

[19] The figure is from *Permissible Loading of Oil-Immersed Transformers and Regulators*, United States Department of the Interior, Bureau of Reclamation, Facilities Engineering Branch, Denver Office, April 1991. This specific example is for self-cooled and water-cooled transformers designed for a 55°C temperature rise; other designs show similar patterns.

[20] Utilities recognize that the length of overloads is critical to determining whether a transformer needs to be replaced. For example, PEPCo and Delmarva Power and Light have established standards for replacing line transformers when the estimated average load over a five-hour period exceeds 160% of the rating of overhead transformers or 100% for padmount transformers. They have not found it necessary to establish comparable policies for shorter periods.

Figure 6: Permissible Overload for Varying Periods



Similarly, if the transformer's high-load period is currently eight hours in the afternoon and evening, and the preceding load is 50% of rated capacity, afternoon load reductions cut the high-load period to three hours would increase the permissible load from about 108% of rated capacity to about 127%. Under these circumstance, the transformer can meet higher load without replacement or addition of new transformers.

Short peaks and low off-peak loads allow the transformer to cool between peaks, so that it can tolerate a higher peak current. Long overloads and higher load levels increase the rate of aging per overload, and frequent overloads lead to rapid failure of the transformer.

In a low-load-factor system, these high loads will occur less frequently, and the heavy loading will not last as long. If the only high-demand hours were the 12 monthly peak hours, for example, most transformers would be retired for other reasons before they experienced many overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life.

With high load factors, there are many hours of the year when the transformers are at or near full loads. Thus, the size of the transformer must be increased to limit overloads to the small amount that is compatible with acceptable loss of service life per overload for this frequency of overloads, or the transformer will burn out far too rapidly.

3. Distribution costs

The factors driving load-related distribution costs are similar to those for transmission. Substations and line transformers must be larger, or will wear out more rapidly, if they experience many high-load hours in the year, and if daily load factors are high. Underground and overhead feeders are also subject to the effects of heat build-up from long hours' use.

The allowable load on distribution lines is determined both by thermal limits and by allowable voltage drop.

F. Cost-of-Service Study

A cost-of-service study converts accounting data, load data, and other inputs into class cost allocations, typically through a three-step process of functionalization , classification and factor allocation.[21]

The principal objective of a cost-of-service study is the fair and equitable sharing of the utility's total revenue requirement among the rate classes. Equity has many dimensions, and is subject to multiple interpretations, leaving room for legitimate disagreements over allocation approaches. Important approaches to cost allocation include:

- Each class's contribution to the current *need* for the equipment and services.
- Each class's contribution to the current *usage* of the equipment, or of the services that require the expenditure. Some regulators have a policy prohibiting "free riders," and require any class that uses a type of equipment to contribute towards the cost of that equipment, even if that use does not drive the costs.
- Each class's contribution to the rationale for undertaking a cost. In some cases, transmission and distribution systems are extended into new areas to serve major

[21] Unfortunately, practitioners use the term "allocation" to refer to the any of the following: the last of the three steps in a traditional cost-of-service study, the entire process, and the final result. I will try to be clear about which meaning I am using in context.

customers (mines, factories, resorts); while some houses are served along the way, the line extensions would not have been justified without the anchor loads.

- How much each class currently uses the service that created a cost in the past. For example, if a power plant is retired and the building is used to house a small meter workshop, any costs left over from the property's use for generation may be allocated as generation, even though it is no longer providing energy or capacity.

Allocation of some cost items, such as DSM expenditures, can be complicated by differences between the classes that received the service and the classes that benefit from the service.

Other allocation issues are complicated by the fact that the same expenditure is required for each of several classes. For example, the cost of the right-of-way and towers for the branch transmission line that serves Daguao (or Acacias or Caonillas or Hatillo) is required for each of the classes in Daguao, just to serve the area, whether the other classes exist or not.

1. Functionalization

Most cost-of-service studies recognize four or five *functions:*

- Generation—the power plants and supporting equipment, such as fuel supply and interconnections.
- Transmission—high-voltage lines (for PREPA, 38 kV, 115kV, and 230kV) and the substations connecting those lines, moving bulk power from generation to the distribution substations.
- Distribution—lower-voltage primary feeders (for PREPA, 4.16kV and 13.2kV) that run for many miles, mostly along roadways, and the distribution substations that step power down to distribution voltages; line transformers that step the primary voltages down to secondary voltages (mostly the 120V and 240V).
- A group of activities—metering, billing, responding to customer inquiries, collecting and writing off bad debt—that various utilities call "customer services," "customer costs" or "retail costs."

- Sometimes overhead costs, such as management, public relations, human resources, and legal staff, and the general plant (buildings and equipment) that supports all the functions. [22]

In most cases, functionalization decisions can follow the utility's accounting. The investment that is booked as generation units is usually part of the generation function. But there are exceptions. For example, some equipment that looks like a transmission line, and is recorded on PREPA's books as transmission plant, functions as part of generation, connecting a generator to the transmission grid and stepping up the generator output to transmission voltage. Other equipment may be booked as transmission, but really function as part of the distribution system, such as parts of substations that transform transmission voltages to distribution,

Various utilities further divide these functions, sub-functionalizing such costs as the following:

- Within generation, segregating plants by technology or operating pattern (e.g., base load versus peaking).
- Within transmission, segregating lower-voltage sub-transmission (e.g., PREPA's 34-kV) facilities from higher-voltage 115-kV and 230-kV facilities.
- Within distribution, separating substations, poles, overhead and underground conductors, line transformers and services; and separating primary from secondary equipment.

2. Classification

A typical cost-of-service study *classifies* each function, sub-function, or account within a function as being driven by one or more of three categories of factors: demand, energy and the number of customers. Fuel is classified as energy-related, generation and transmission are typically classified as demand- and/or energy-related, and the various portions of distribution costs are classified as some combination of demand and energy.

[22]Some COS studies treat overhead as a function, and allocate those costs to classes in proportion to the total costs (or a portion of costs, such as plant or expenses) allocated to other functions, or on such drivers as the labor cost incurred by each of the other functions. Others functionalize a portion of each category of general plant and overhead expense to each of the other four functions. The same ultimate cost allocation can be achieved either way; the structure of the COS does not constrain or distort the allocation of overhead costs.

3. *Factor Allocation*

Finally, a cost-of-service study applies an *allocation factor* or *allocator* (a percentage breakdown among classes) to each cost category. Within each broad type of cost driver, a cost-of-service study uses multiple allocators for various cost categories. For example, within the demand classification,

- The demand-classified portion of generation plant may be allocated in proportion to class contribution to the average of the twelve monthly coincident peaks (CPs).
- The demand portion of transmission may be allocated on class contribution to the average of a few of the highest monthly CPs.
- The demand portion of distribution may be allocated in proportion to the class's non-coincident peak (NCP), for the classes that use distribution.

Customer allocators are often weighted by the average cost of providing the service to customers in the various classes, so that the cost of customer relations may be allocated with a weight of 1 for residential customers, 2 for small commercial, five for medium commercial, and 20 for industrial.

4. *Multiple allocation pathways*

Any particular choice of functionalization, classification or allocation factor is not necessarily critical to the class cost allocations, since the cost-of-service study can get to the same final allocation in several ways. For example, the reality that a portion of transmission costs are driven by the need to interconnect remote generation can be reflected by functionalizing a portion of transmission cost as generation, classifying a portion of transmission as energy-related, or using a transmission demand allocator with some energy component.

5. *Results of the cost-of-service study*

The principle output of the cost-of-service study is a breakdown of the implied revenue requirement responsibility by class. In addition, cost-of-service studies usually also provide information on the breakdown of costs allocated to each class by function and classification.

G. Revenue Allocation

Even though the cost-of-service study involves many decisions and computations, it does not determine the revenues that will be collected from each class. That allocation of the rate increase is a policy decision, informed by the cost-of-service study; the degree of the regulator's faith in the cost-of-service study; concerns about rate shock, gradualism, financial capability of the classes, and other factors.

H. Rate Design

Once the revenue to be collected from each class has been determined, the regulator must determine how the costs will be collected. The following rate-design elements are the most common parts of retail rates:

- Fixed customer charges in $/month.
- Energy charges in ¢/kWh, which may vary:
  - By season.
  - By usage, with the rate increasing or decreasing as monthly use increases.
  - By time of day, if the metering supports collection of those data.
  - By system condition, if metering allows for measurement of hourly usage.
- One or more demand charges in $/kW-month or $/kVA-month, measured when the customer experiences its maximum load (where metering allows that measurement), with such variants as:
  - Measurement over fifteen minutes, an hour, or some longer period.
  - Measurement in all hours, or only during on-peak hours (e.g., 8 AM to 10 PM).
  - Computed on the maximum demand in the current month, on ratcheted demand from the past year, on contract demand, or some combination.[23]

Other rate-design options include splitting an existing class (based on usage pattern, usage level, end use, socio-economic status, etc.), merging existing classes, and closing existing rates to new customers while letting grandfathered customers remain on the rate.

I. Limits in PREPA Data and Filings

PREPA's cost allocation and rate-design proposals are based on data that is often not representative of customer usage patterns and cost causation. Each of the following challenges is discussed in detail in Sections II.D to II.H.[24]

[23] For example, the billing demand for PREPA's current GSP and GST tariffs are computed as the maximum of (a) the monthly metered demand, (b) 60% of the highest load in the previous 11 months, and (c) 60% of contract demand.

[24] The actions and errors I ascribe to PREPA may well be result of critiquing its consultants, past and current, rather than PREPA itself. It is not always clear who is responsible for problems in

- PREPA's estimates of class demand allocators do not represent the load characteristics that drive PREPA's costs.
- PREPA does not have consistent hourly usage data across classes.
- PREPA has not estimated any measure of coincident peak by class, or the class contribution to transmission and distribution peak loads.
- PREPA has not performed a recent loss study for transmission and distribution losses.
- PREPA analysis and presentation of its claimed subsidies in ratemaking, cost allocation and rate design have been inconsistent and confusing.
- PREPA's original cost-of-service study incorporated important conceptual and computational error, including the inability to properly compute the industry-standard average-and-excess demand (AED) allocator.
- The update cost-of-service study introduces new errors.
- PREPA's consultants were unable to justify many of their cost allocation and rate-design proposals, including the failed attempt to use the AED allocator and the proposed rate unbundling.

As a result of the numerous problems with PREPA's cost-of-service study, that study is not useful for allocating costs or revenues among tariffs. Some of the errors could be corrected within the duration of the current proceeding, but other problems, particularly the lack of load data, cannot be overcome during the schedule for this case. Turning PREPA's effort at cost allocation into a reasonable approximation of the cost-of-service studies widely implemented across North America will require at least one additional proceeding, and likely a series of reviews.

The PREPA marginal-cost study is also too badly flawed to use in rate design. Rehabilitating the marginal-cost study should be feasible in a rate-design proceeding in 2017.

These and other problems are discussed in more detail in subsequent sections.

J. Summary of Conclusions and Recommendations

1. *Triage of issues*

a. Issues ripe for determinations in the this proceeding

PREPA's initial filing in this proceeding had problems that PREPA has not been able to correct, and many of PREPA's responses to discovery have been misleading, incomplete,

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the analysis. PREPA must determine where the problems originate and improve future analyses, as I discuss in Section IX.)

and inconsistent.[25] As a result, it has been difficult and time-consuming to determine what PREPA and its consultants knew, and what they did in preparing the filing.

Nonetheless, the following issues can, and in many cases, must be decided in this proceeding:

- Allocating responsibility for revenues among classes.
- Determining whether to include base levels of fuel and purchased-power costs in base rates.
- Setting fixed monthly customer charges for residential and small-commercial tariffs.
- Distributing rate increases between energy and demand charges for larger non-residential customers.
- Retaining or changing the GRS inclining block.
- Retaining or closing the TOU rates.
- Resolving the level of subsidies to be recovered, as well as the recovery mechanism.
- Determining whether tariffs will be unbundled into generation, transmission and distribution components, as PREPA proposes.
- Making initial determinations regarding issues that will be considered in detail in later proceedings (*e.g.*, for distributed generation and net metering) or on a case-by-case basis (*e.g.*, load-retention and economic-development rates).

b. Issues that can be deferred to a separate proceeding

- Cost allocation and the cost-of-service study methodology
- Marginal cost study
- Estimating loss factors
- Rebalancing energy and demand charges
- Reviewing inclining blocks for residential rates

[25] Some of these problems arise from PREPA's history of budget constraints and lack of an overall vision for data collection and retention.

- Reviewing structure of discounted residential rates
- Optimizing TOU rate prices and periods
- Expanding TOU options
- Seasonal rates
- Improved unbundling
- Designing details for distributed generation and net-metering rates

The Commission deferred many of these issues in its Resolution of November 3, 2016 (CEPR-AP-2015-0001).

2. Revenue allocation

PREPA proposes to increase most non-residential customer classes' total revenue allocation (excluding the transition charge) by a bit more than half of the average percentage revenue increase. To make up the difference, the residential revenue requirement would be increased twice as much, about 117% of the system average. The public lighting rates (including the unmetered rates, which are also mostly lighting) would be increased by eight times the system average. Since the public lighting rates are mostly used by municipalities, who are not required to pay for the lighting service, this latter increase primarily increases the level of subsidies.

Given the serious deficiencies in PREPA's cost-of-service study, the Commission must decide how to allocate revenues in this current rate proceeding on some other basis. Faced with inadequate or inconclusive cost-of-service analyses (not an unusual occurrence), regulators frequently allocate revenue increases on an equal percentage or equal cent-per-kWh basis across rate classes. If no specific aspects of the revenue allocation can be determined to be inequitable, unfair, or unreasonable, there is no basis for assuming that any particular change in the allocation pattern would represent an improvement. I therefore recommend that the Commission apply an equal revenue adjustment for most tariffs in this proceeding, while moving to improve the available analyses in the upcoming rate-design proceeding.

As I discuss in Section VII.D, PREPA's proposed average revenue per kWh for the non-subsidized GRS tariff is low, compared to the proposed revenue per kWh for the general-service classes. Hence, I recommend that the Commission increase the revenue allocation to the GRS class (and hence to the other residential classes that use the GRS tailblock) by a few percent more than the system average.

3. *Riders*

Act 57-2014 and Act 04-2016 require that PREPA increase customer bill transparency by adding line items on the bill for subsidies, CILT, fuel and purchased power. PREPA has proposed that each of those items be a separate reconciling rate rider.

a. Subsidies and CILT

PREPA has proposed that subsidies and CILT be allocated to classes in proportion to energy sales and recovered through a uniform system-wide charge on all classes except the RH3 customer class.

The CILT costs are treated reasonably in rate design. Since it is likely that PREPA will be reconciling all costs at least annually for the foreseeable future, no special reconciliation mechanism is necessary for the CILT charge.

PREPA has proposed that customers in the LRS, RFR and RH3 tariffs be exempt from the subsidy charge, in addition to the RFR class being exempt from the CILT charge, and reflects those exemptions in its rate-design computations. The current record contains no analysis of the need of the low-income customers for this additional assistance, compared to the burden on other tariff classes, or the equity of exempting some subsidized customers but not others. The Commission should reconsider in the separate rate-design proceeding which discounted rates should be exempt from the CILT and/or subsidy charges, and how those charges should be reflected in rate design for tariffs in which some or all loads are discounted. Unless additional information emerges in the hearing, I recommend that the Commission accept PREPA's proposed exemptions for the purposes of this proceeding.

PREPA's treatment of the CILT and subsidies in cost allocation is inconsistent with the policy goals of the legislature and PREPA itself. PREPA fails to subtract intentional, policy-driven subsidies (including exemption of some customers from the subsidy and/or CILT changes) from the target revenues for each affected tariff class. PREPA should improve the tracking of CILT and subsidies in both the cost-of-service study and rate design.

As I explain in Section V.B, PREPA's proposed subsidy rider includes some costs that are not subsidies, and others that cannot be determined to be subsidies absent improved load and cost of service data.

b. Fuel and purchased power

Currently, PREPA recovers all of its fuel costs and purchased-power costs through two separate, but very similar, cost riders that it sets and reconciles on a monthly basis. PREPA proposes to include the forecast level of fuel and purchased-power expense in base rates, and to recover only the deviation from those forecasts through the FCA and PPCA. This approach is revenue-neutral and has no inherent adverse effects on cost allocation or rate design. Some rate-design options, such as inclining-block rates and time-of-use rates, may be easier to structure with the fuel and purchased-power costs folded into base rates as PREPA proposes.

On the other hand, PREPA is required by Act 4-2016 to show the customer's entire fuel charge in a single line on the bill, and the total purchased-power cost on another line. Since the base and rider portions of fuel and purchased power would need to be combined on the bill, keeping fuel and purchased power costs entirely in the rider rather than in base rates may be easier to present and less confusing for customers. Whether fuel and purchased-power costs are largely in base rates or entirely in riders, the customer should observe the same total rate, and a well-informed customer will respond to either rate design with the same pattern or consumption and conservation. Hence, customer understanding is a key consideration in this particular rate-design issue.

In addition, as noted in the report of Commission experts Fisher and Horowitz, the forecast of fuel costs for FY 2017 provided in the original filing and reflected in PREPA's rate-design proposal appears to be far too low. Messrs. Zarumba and Garnovsky agree that fuel costs for FY 2017 will be significantly higher than they originally anticipated, but recommend proceeding with the base rates that include only the original low forecast of fuel costs and recovering the difference in the fuel-cost rider. Customers may be further confused if PREPA initiates the new rate design, intended to include the bulk of fuel costs in base rates, with a large part of the fuel cost in the rider.

While there are pros and cons to moving costs into base rates, that action appears to be il-timed and premature.[26] Unless new information becomes available through the hearings, I recommend that the Commission require that all fuel and purchased-power cost be collected through the riders.

4. Tariff-specific rate design issues

In Section VII, I discuss a number of PREPA's rate-design proposals that should be modified. The major changes I would make are to keep the tariffs bundled, increase energy charges rather than demand charges; keep the time-of-use rates open; and maintain the GRS inclining-block rate.

[26] One of PREPA's objectives in combining a base level of fuel and purchased-power costs in base rates may be the desire to classify and allocate the fixed portion of purchased power on a basis other than energy. When the Commission determines the appropriate allocation of purchased-power costs, PREPA can reflect that decision in setting different PPCA rates for each tariff class.

II. The Embedded Cost-Of-Service Study

A. Purpose of an Embedded Cost-Of-Service Study

The purpose of an embedded cost-of-service study is to equitably divide responsibility for paying the utility's revenue requirement (in this proceeding, the projected costs for FY2017) among classes and rate tariffs. It is not a guide to rate design. The cost-of-service study results identify which classes use the services that resulted in today's costs, but do not really indicate who caused which costs.[27]

Rate design, in particular, should be driven primarily by marginal costs, rather than average embedded costs.

B. The Structure of an Embedded Cost-Of-Service Study

An embedded cost-of-service study can be structured in several ways, but the most common conceptual process consists of three steps: functionalization, classification and factor allocation. Generally speaking, functionalization identifies the purpose served by each cost, classification identifies the general category of factors that drive the need for the cost, and factor allocation selects the parameter to be used in allocating the cost among classes.[28]

1. Functionalization

Cost-of-service studies divide the utility's accounting costs into a handful of top-level *functions*, such as generation, transmission, distribution, plus a category of costs directly related to connecting and interacting with customers (which may be called "customer" or "retail" costs), and a category of shared overhead costs that serve the other functions (*e.g.*, administration, financial, legal services).

This top-level functionalization of costs is driven by accounting records, and most of the functionalization decisions are non-controversial. In some situations, the function of an investment may not match the accounting category. Examples include the following:

- Transmission lines and substations that are dedicated to connecting generation to the transmission network: These assets are often in the accounting records as transmission but are functionalized as generation.

[27] For example, an investment made in the 1980s to serve the energy requirements of factories that have since shut down may be equitably allocated to the classes in proportion to their current use of energy. But it would not be correct to say that today's customers caused that investment.

[28] The third step is usually called "allocation," which is the same as the name of the entire process. To reduce confusion

- The substations connecting transmission to distribution, but also providing transmission services: These which might be carried in the accounting records as entirely transmission or entirely distribution, but split between transmission and distribution in the functionalization process.
- Equipment within transmission substations that are look like distribution equipment (e.g., poles, line transformers, secondary conductors, lighting): These might be be booked in distribution accounts, but are functionally part of the substation.

In addition, many cost-of-service studies sub-functionalize some costs within a function, such as the following:

- Within generation,
  - Segregating baseload generation (which runs whenever it is available, or nearly so) from intermediate generation (which typically runs several hours daily) and peaking generation (which runs only in a few high-load hours and when other generation is unavailable)
  - Separating generators by technology, to recognize such factors as renewable resources procured to meet energy-based environmental goals and the differing reliability contributions per kilowatt of various technologies (e.g., wind, solar, thermal).
- Within transmission,
  - Segregating lower-voltage subtransmission facilities (under 100 kV) from higher-voltage facilities.
  - Treating interconnections differently from the internal generation network. (Not applicable to PREPA)
  - Separating substations from lines.
  - Separating underground from overhead lines.
- Within distribution,
  - separating substations, lines (comprising overhead poles, underground conduit, and the wires) and line transformers.
  - Dividing lines into primary and secondary components.
- Within customer costs,
  - Subfunctionalizing meters, services, meter-reading, billing, customer service and other components, each of which may be allocated separately.
- Within general costs,

- Subfunctionalizing by type of cost: pensions and benefits, property insurance, legal, regulatory, administration, buildings, office equipment, and so on.

2. Classification

The second step of the classic ECOSS *classifies* each function or sub-function (i.e., each type of plant and expense) as being caused by one or more categories of factors. In particular, most cost-of-service studies use the classification categories of demand, energy and customer number, and some use other categories. PREPA uses a relatively granular classification scheme, including four demand-related classification categories (production, transmission, primary distribution and secondary distribution), two energy categories (streetlighting and other), contributions (covering CILT and subsidies) and net income.

3. Factor allocation

The final step of the allocation process is the application of an allocation factor or *allocator* to each cost category.[29] An allocator is a percentage breakdown of the selected cost driver among classes. Within each broad type of cost driver, utilities use multiple allocators for various cost categories, such as various measures of contribution to coincident peaks (a single annual peak, or 1 CP; the average of several high-load monthly peaks; the average of all twelve monthly CP contributions (12CP); average of dozens of high-load hours), or the class annual maximum load (non-coincident peak or NCP) at any time during the year, all of which are used as measures of demand. Generation allocators are sometimes differentiated among resources, to reflect the usage of different types of capacity and to retain the benefit of legacy resources for historic loads. Customer allocators are often weighted by the average cost of providing the service to customers in the various classes.

4. Roles of functionalization and classification

While they are convenient parts of organizing a cost-of-service study, functionalization and classification decisions are not necessarily critical to the final class cost allocations. The cost-of-service study can get to the same final allocation in several ways. For example, the reality that a portion of transmission costs are driven by the need to interconnect remote generation can be reflected by functionalizing a portion of

[29]Note that allocation is the term normally used for the entire process of assigning revenue requirements to classes, and is also the term used for the last step of that process.

transmission cost as generation, classifying a portion of transmission as energy-related, or using a transmission demand allocator with some energy component.[30]

5. The COSS model

The ECOSS should be transparent and flexible, to allow both the utility and interested parties to examine and make changes in a consistent manner. Model users should be able to change allocation decisions in a central location on the spreadsheet and have those changes follow through the model's calculations.

When a cost-of-service study model is transparent and flexible, both the utility and interested parties are able to check the calculations, confirm their understanding of the methodologies, evaluate the impact of the Company proposals on rate classes, and develop alternative ECOSS methods.

C. Principles of Cost Allocation

1. General principles

In reviewing the COSS, the Commission should apply a number of guiding principles, particularly the following:

- The study should serve only as a guide to revenue allocation, not as the sole determinant. Even the best cost-of-service study reflects many judgments, assumptions and inputs; other reasonable judgments, assumptions and inputs would result in different cost allocations. In addition, concepts of equity extend beyond the cost-of-service study's assignment of responsibility for causing costs or using the services provided by those costs, to include relative ability to pay, gradualism in rate changes, and other policy considerations.
- Consideration of marginal cost and incentive effects should be reflected in rate design. Hence, cost allocation should not usually be driven by concerns about allocation affecting rate design.[31]
- The principal objective of a COSS is the fair and equitable sharing of embedded costs. These terms are subject to multiple interpretations.

[30] Nova Scotia Power, for example, uses a transmission demand allocator that is a driven about 62% by class energy use and 38% by class contribution to the peak loads in each of its three highest-load months.

[31] Occasionally, cost allocation may constrain rate design, by limiting the revenue requirements available to design rates. When those situations are identified, the allocation of revenues among classes may be modified to allow efficient and effective rate design. Given PREPA's high embedded costs, this is unlikely to be an issue in Puerto Rico.

- The touchstone for equity in the COSS is class contribution to the current and historical causation of costs. Most costs are equitably allocated on the current usage of equipment and services; some legacy costs may be more equitably allocated on past usage.
- Cost of service allocation only splits costs among classes and does not directly determine rate designs or provide price signals to customers. In some cases, providing adequate price signals may require redefinition of rate classes or other changes to the cost allocation.
- Cost causation should be assessed by using the most realistic practical analysis of the measurable factors that cause or drive the utility to incur various costs. Excessively simplified concepts of cost causation should not be allowed to distort allocation in identifiable ways.
- Costs should be allocated on the best available data.
- Whenever possible, the rules for cost allocation should be consistent among classes.
- Cost causation should distinguish between complementary or alternative investments, which substitute for one another, and incremental investments, which add costs to the system.
- Allocation should strive for geographic equity, treating classes similarly, regardless of the historical accidents of the vintage and design of the system across the service territory. Thus, the fact that one class happens to have a disproportionate share of its members in areas with higher distribution costs should not normally be a consideration in the allocation of distribution costs.
- The factors used in the COSS should be derived from straightforward methods that can be revised in the future to reflect changes in customer characteristics, loads, and changes in system characteristics.

2. Incremental and complementary investments

Customers receive service at various voltages and with a variety of equipment. Most of the distinctions between types of equipment represent alternative or complementary methods for providing the same service. For example, various feeders operate at 4 kV, 13 kV, or 25 kV, and as overhead or underground construction, depending on load density, age of the equipment and other considerations. While the power flowing from generation to a customer served at 25 kV may not flow over any 4-kV feeder, the 4-kV feeders serve the same function as the 25-kV feeders and (in places in which they are adequate) at lower cost. Serving some customers at 4 kV and spreading the feeder costs among all distribution does not increase costs allocated to the customers served directly from the

25-kV feeders; converting the 4-kV feeders to a higher voltage would increase costs to all distribution customers, including those now served at 25 kV.

On the other hand, some distinctions in voltage level represent incremental investment:

- In some cases, a distribution substation and feeder can bring service to customers that would otherwise be served by an extension of the transmission system at higher cost. However, most customers served at distribution voltages cannot take service directly from the transmission system. Even if a transmission line runs right past a supermarket or housing development, PREPA must run a feeder from a distribution substation to serve those customers. Distribution in its broadest sense is thus principally an incremental service, rather than an alternative service, needed by and provided to some customers but not all.
- Similarly, most customers who take service at secondary voltage have a primary line running by or to their premises, yet cannot take service directly at primary.[32] The line transformers are incremental equipment that would not be necessary if the customers could take service at primary.[33]

These incremental costs should be functionalized so that they are allocated to the loads that incur them, while each group of complementary costs (such as various distribution voltages) should be treated as a single function and recovered from all customers who use any of the alternative facilities.

In other situations, distinguishing between incremental and complementary costs can be a little more complicated. Examples include the treatment of transmission equipment at different voltages and the treatment of secondary poles.

Yet many utilities treat subtransmission as an incremental cost, and charge more for delivery to customers at subtransmission, even though they are less expensive to serve.

Similarly, distribution poles carrying only secondary lines are less expensive than poles carrying primary. If a customer served by a secondary-only pole had decided to be served at primary instead, the primary pole would have been more expensive and that higher cost would have been allocated to all distribution customers. Secondary poles (unlike line

[32]Another way of looking at this relationship is that secondary customers are those for whom providing service at secondary has a lower total cost than providing service at primary. Sharing utility-owned transformer capacity is less expensive than having each building own its own transformer. See Section I.D.3 for a discussion of primary and secondary distribution.

[33] While most secondary conductors parallel primary lines and are incremental to the primary system, some secondary conductors that extend beyond the primary lines are complementary, since they avoid the need to extent primary lines.

transformers and most secondary lines) are lower-cost alternatives to some primary poles.[34]

D. PREPA's Approach to Functionalization

The PREPA/Navigant ECOSS model recognizes five top-level *functions*—Generation, Transmission, Distribution, what PREPA calls "Customer,"[35] and General, which includes shared costs supportive of the other functions. PREPA functionalizes a portion of each category of general plant and overhead costs to each of those four functions.

Other cost of service studies treat overhead as a function, and allocate those costs to classes in proportion to the costs allocated to other functions, or on such drivers as the labor cost incurred by each of the other functions. In this regard, the structure of the cost of service does not constrain or distort the allocation of overhead costs.

The basic structure of functionalization in PREPA's cost-of-service study is reasonable. While some transmission costs could be refunctionalized to generation, the same outcome can be achieved in the classification or allocation steps of the cost-of-service study.

E. Problems in PREPA's Load Data and Demand Allocators

The amount of generation, transmission and distribution capacity required to serve customers is determined in large part by aggregate loads on each component of the system. Depending on the system and the type of equipment, the important loads may be a few hours a year, a few hours a month, the highest fifty or hundred hours in the year, the average load in several contiguous high-load hours, or total hourly load. The maximum load of any one customer or even one class is much less important, in terms of cost causation, than the maximum total load in Puerto Rico, a city, or a neighborhood.

The COSS spreads costs among classes based on the class contribution to loads that are considered to incur each particular portion of the utility's cost. Frequently used load-related allocators include:

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[34] Similarly, a portion of the secondary lines replaces primary lines. If the customers that can be served with secondary poles required primary service, PREPA would need to extend the primary lines rather than secondary lines. Hence, a portion of secondary lines are also complementary to the primary system, rather than additive. While PREPA does not know how much it spends on secondary plant, the ECOSS treats 40.5% of distribution costs as being required only for secondary.

[35] The function name "customer" is confusing, since "customer" is also a classification, describing the factor that drives the cost. PREPA's "customer" function includes costs that do not vary directly by customer. Other COS studies use other names for this category, such as "retail costs"; I am not aware of a particularly clear title for this group of costs.

- the class contributions to the annual system coincident peak (CP),
- the average of the class contributions to multiple high-load hours, such as the twelve monthly peaks (12 CP) or all hours with coincident peaks greater than a threshold (such as 95% of annual peak),
- the average of class load contributions at times of particular types of stress, such as substation peak loads,
- the class maximum peaks regarding of timing (non-coincident peak or NCP),
- and energy in all hours or in high-load hours.

Most utilities develop estimates of class load factors using a program of hourly metering for a subset of customers in each class, to support an estimate of each class's load shape, including coincident peak by month, non- coincident peak by month, percentage of energy used in the high-load hours, and other information useful for planning and cost allocation.[36] Load research provides data needed to develop allocators that measure class contribution to periods of high system loads.

1. Inconsistent sources of load data

PREPA and its consultants understand how to conduct load research by constructing a statistically significant sample of the load data for a class:

> In terms of how the sample of customers was selected (when applicable), in a total group of customers (universe) of a particular tariff (or the ones with hourly data storage capability) it is possible to select a valid statistical sample. The universe of customers is categorized in strata classified by the consumption of that group of customers. Once the customers are stratified, it is proceed to extract a sample by means of the calculation of the average, mean, deviation and standard deviation, via a previously designed formula. When the formula is executed we will obtain a smaller number of customers representative of the customer strata. The number will be the sample (n) in the universe (U) of every strata. The number (n) is the number of customers to study to know the representative behavior of each strata of customers. (CEPR-PC-04-10)[37]

However, PREPA does not currently have a load research program.

[36] Most utilities have developed load shapes by class from hourly metering samples, since at least the 1970s. The Public Utility Regulatory Policies Act of 1978 required gathering of "daily kilowatt demand load curves for each electric consumer class for which there is a separate rate, representative of daily and seasonal differences in demand" (16 USC 2643. Sec. 133)

[37] A similar detailed explanation is provided in CEPR-PC-7-21.

> PREPA does not have an established meter data management and load research capability, neither in terms of hardware, software nor trained personnel to perform such analyses, and existing systems must be improved to achieve the desired daily reads. (CEPR-PC-08-04a)

In the absence of a current load research program, the cost-of-service study relies on a mix of data from several different years, as provided in CEPR-PC-02-020, CEPR-PC-04-016, CEPR-PC-04-17 and CEPR-PC-07-20a:

- Hourly load data from FY 2009 (July 2008 to June 2009) for tariff code 312, the industrial portion of the GSP rate.
- Hourly load data from FY 2010 (July 2009 to June 2010) for some sample of the customers in each of the RH3, LRS, GRS (codes 111 and 112), GAS, and GSS (codes 211 and 311) tariffs.[38]
- Hourly load data from FY 2014 (July 2013 to June 2014) for "the available clients" (some but not all customers) on some special rates (codes 603, 613 and 653).[39]
- Hourly load data from FY2009 for "the available clients" on GST (codes 213 & 313).[40] For tariff code 313, PREPA provides a particularly obscure response, which seems to be saying that PREPA invented much of the data for this tariff code:

  > The exercise was based on the customers connected to the different Transmission system bars, using real and simulated data. This was completed using three different approaches.

[38] Mr. Zarumba says that, for these rates, "load factors values are the same as used in FYs 2009 and 2010" (CEPR-PC-04-11). But if the load data are from FY 2010, as shown by the dates in CEPR-PC-02-020, they could not have been used in FY 2009. Resolving these inconsistencies in PREPA's descriptions of its data may be easier in a less formal stakeholder process leading to the rate-design proceeding.

While the cost-of-service study treats RH3 and LRS customers above and below 425 kWh/month as separate tariff codes, PREPA uses the same load shape for both the large and small customers. PREPA uses separate load data for the GRS customers covered by the fuel-oil discount (tariff code 111) and other GRS customers, and for the commercial and industrial customers on the GSS rate.

[39] The response to CEPR-PC-7-22a shows the number of hourly meters (which PREPA suggests were all MV90 meters in CEPR-PC-7-22b) by tariff code. Using data from a subset of customers that have MV90 meters may introduce bias, depending on how these customers were selected for the MV90 meters in the first place.

[40] The response to CEPR-PC-04-12 indicates that the GST data are from FY2013, but CEPR-PC-07-09 states that the data are from FY2009. The hourly data with date tags were not provided in CEPR-PC-02-020.

i. Available real data – there were customers which had real data for the full period (FY 2009) and some which had part of it. For these:

   a) Full period real data – hourly load curves were simulated using real data.

   b) Partial period real data – hourly load curves were simulated using real data and typical days, based on available real data.

ii. Non-available real data– there were customers for which real data was not available for the full period. For these customers, the hourly load curves were simulated based on other customers with real data available (normalized based on kWh). The normalized load curve used to represent a customer without data, depended on the type of client (i.e. commercial, industrial), type of business (i.e. pharmaceutical, utility water pumps) and LF value. (CEPR-PC-7-20c)[41]

- Hourly load data from FY 2014 for all customers on LIS and related special rates (tariff codes 333 & 673), PPBB, the Navy GST accounts (513), and the standard and special TOU rates.
- Load data from the RH3 sample applied to the RFR class.
- Load factors computed from a lost 2002 load study for unmetered cable TV tariff codes 70, 71 and 80.
- Data from a 1996 study for Public Lighting code 424.
- Assumed load shapes for other unmetered and public-lighting tariffs, based on daylight hours for Public Lighting codes 421 and 422, and Unmetered Services 060-061, 072 and 073.
- Data from FY2009 for commercial GSP (CEPR-PC-04-14). “For tariff code 212, data obtained from available meters was used to emulate a representative load curve (for a year) which provides monthly LF values” (CEPR-PC-04-15).[42] From CEPR-PC-04-21, it appears that these data were available for only one week, in October 2008.[43]

[41] I understand PREPA to be saying that it used real data for a portion of this class, a combination of real and made-up loads for a second portion, and entirely made-up loads for a third. PREPA does not specify the portion of the tariff code in each of these categories or provide any data on the process for estimating the missing data.

[42] The data and “emulation” have not been provided to the Commission's consultants.

[43] The response to CEPR-PC-07-022 suggests that PREPA obtained some current load data from MV90 meters for tariff code 212, but PREPA did not provide any such data in CEPR-PC-02-020.

- Similarly, CEPR-PC-04-016 claims that LP-13 (414) loads were estimated from "data from the available clients," but has not provided those data or specified the vintage of the data.

Much of the information essential to a review of the reasonableness of the load data and load calculations is not available

2. *Missing data and computations*

For the major secondary tariffs (RH3, LRS, GRS, GSS and GAS), PREPA describes its process for developing load data in general terms, but has not been able to provide any details:

> Almost all clients at secondary distribution voltage service have meters with capability for remote reading (daily). In addition, many of these meters can provide for hourly data storage. This exercise was performed for FY 2010.A random sample by tariff was selected, from a group of clients with remote reading meters with hourly data storage capability. CEPR-PC-04-016

The data used to derive demand allocators for these tariffs is not currently available because of a "data storage failure" affecting the tariffs (CEPR-PC-07-22a) that occurred "around May of 2010."[44] In particular, PREPA is unable to provide the number of meters sampled in each of these classes and the data from each meter (CEPR-PC 07-20b). It is also unable to document the load research method, including the usage strata developed for sampling customers and the number of customers selected for each stratum (CEPR-PC 07-21 b and c).

PREPA has not provided any hourly load data for tariff codes 212, 213, or 313. (CEPR-PC-2-20). It is not clear whether PREPA has these data or the workpapers from which the load shapes were estimated.

3. *Problems in PREPA's development of demand allocators*

a. Estimates of non-coincident peak loads

Messrs. Zarumba and Granovsky claim that, PREPA's lack of a load-research program precluded the estimation of the contribution of the various classes to the system peak load (the coincident peak or CP) (Exhibit 8.0, page 16). Their explanation for the absence of these important data is that customers equipped with hourly metering constitute only about 14% of the peak load (Exhibit 8.0, page 17), so PREPA lacks information about the peak contribution of the classes making up the other 86% of peak load.

[44] Since FY2010 extended through June 2010, and analysis would have required some additional time, it is difficult to see how PREPA could have lost these data in May 2010.

Instead, Navigant derived the allocators for fossil generation plant, fixed PPA charges, transmission and most distribution using an estimate of each tariff code's annual non-coincident peak (NCP) load in 2014. PREPA intends that the NCP loads represent the maximum combined load of the customers in that tariff code, whenever that load occurs.

The NCPs, even if they were properly computed, would be entirely inappropriate for allocating equipment shared among the rate classes. PREPA does not have one generation system for residential customers, another for street lights, another for secondary commercial customers, and so on. The vast majority of transmission lines serve a wide mix of classes. Most distribution substations and feeders also serve a mix of classes. In the real world, customers are mixed together in the real world, sharing distribution, transmission and generation resources. The loads that matter are at the times of high loads each line, each transformer, and the generation system, not at the times of the maximum load of a class or tariff code.

Just as PREPA did not know the load of most customers at the time of the system monthly or annual peaks, PREPA does not know the date or time of the 2014 NCPs, let alone the load of each class. Navigant produced its estimate of 2014 NCPs in a three-step process:

- For whatever year's load sample was available for each tariff code, determine the monthly energy and non-coincident peak of the sampled load and computed the NCP load factor for that month.[45]
- For each month in FY 2014, multiply the tariff code's monthly energy by the monthly load factor from the sample, to estimate a monthly NCP.
- For each tariff code, select the highest of the estimated monthly NCPs.

Navigant used the highest monthly NCP (as estimated in the three-step process) for each tariff code within a rate class, which is even less realistic as a cost driver than NCP at the class or tariff level. Applying an NCP-based allocator by tariff code uses different peak hours, days and months for neighboring customers in the same rate class. For example, in the non-public-housing residential class, small LRS and subsidized GRS customers are treated as peaking in February, large LRS and non-subsidized GRS customers in October, and net-metering in June. Navigant estimates that the public-housing tariff codes (which all use the same load shape) reach their NCP in yet another month (November). Non-residential tariff code NCPs are spread over eight months, as shown in Table 1.

[45] Monthly load factor = monthly average load ÷ monthly peak load
= (monthly energy ÷ hours) ÷ monthly peak load.

Table 1: PREPA's Claimed Non-Coincident Peak Month by Rate Code

	PREPA NCP Peak Month	
	Non-Net-Metered	**Net-Metered**
RH3 and RFR (103-107)	Nov	
LRS 109	Feb	
LRS 110	Oct	Jun
GRS 111	Feb	Jun
GRS 112	Oct	Jun
GSS 211	Oct	Apr
GSP 212	Oct	Feb
GST 213	Sep	Sep
TOU-P 862	Jun	
CATV 070-071	Aug	
USSL 082	Feb	
GSS 311	Feb	Nov
GSP 312	Nov	Nov
GST 313	Sep	Jul
LIS 333	Sep	
PPBB 343	Feb	
TOU-T 363	Nov	
TOU-T SBS 393	Oct	
TOU-T 963	Sep	
GST 513	Sep	
GAS 711	Jun	Jun
LP-13 414	Feb	
PLG 421	Oct	
PLG 422	Jan	
PLG 423	Feb	Jun
PLG 424	Feb	
Unmetered 01-045	Jul	

The timing of the NCP for the net-metering customers in several tariff codes demonstrates the arbitrariness of this allocation approach. Lacking load data for net-metering customers, Navigant assumed that the net-metering customers have the same monthly NCP load factor as the regular customers. Since many of the net-metering tariff codes were growing during FY2013, as additional customers installed solar equipment, Navigant's method tends to select the NCP for the net-metering customers in a later month than the rest of the tariff code, as shown in Table 1. For seven of the eleven net-metering tariff codes, Navigant identifies a later NCP month than the non-distributed generation counterpart. For one tariff code, PREPA identifies the base class NCP as being in June, at the end of the fiscal year, so the net-metering NCP cannot be later. The

NCP months are the same for two tariff codes; only one tariff code has an earlier NCP for customers with net-metering than those without.

b. The option of estimating coincident peak loads

While Navigant chose to develop estimates of NCP by tariff code by month, Messrs. Zarumba and Granovsky claim that they could not estimate coincident peaks, since they did not have current hourly load data for each tariff code.

> In circumstances where all clients within a tariff have hourly load data available in PREPA's MV90, coincident peaks can be obtained. PREPA does not have hourly data for all classes of customers. NCP allocator approach was used, because it does not depend on the moment in where the system's peak happens, and it is possible to have a representative value in tariffs when hourly load data is not available for all clients, which is PREPA's situation since it has limited load research data. (CEPR-PC-02-023)

Contrary to Navigant's claim, reliable estimates of NCP also require hourly load data from a representative sample of customers, just as estimates of CP do. Just as Navigant estimated NCP load factors from whatever data were available, it could have computed the monthly CP load factors (either for a single peak hour in each month, or for an average of high-load hours) as easily as it computed the NCP load factors. Navigant's insistence that it was forced to use a single estimated NCP by tariff code, rather than coincident peak, is not supported by the reality of the data availability.

F. Generation Allocation

1. Classification to energy

Navigant classifies only fuel and fuel additives to energy, while treating all fixed costs of generation (debt service, non-fuel O&M, capital additions and associated overheads and general plant) as being 100% due to estimated annual peak demand.[46] This is not appropriate.

Classification of generation plant as though plant were installed only to meet peak was reasonable in the era when each fossil-fueled utility built only one type of power plant (e.g., coal-fired steam plants) and plants differed only due to their vintage. This notion led to classification of generation as 100% demand-related. Since then, different power production technologies have been developed. In modern utility systems, power-production facilities are built both to serve demand (i.e., to meet reliability requirements) and to produce energy economically. This change means that it is appropriate to allocate some of the plant costs to energy usage rather than to demand.

[46] Navigant uses different peak hours for different tariff codes.

Thus, utilities elsewhere classify fixed generation costs in a variety of ways: Manitoba 100% on energy, weighted to high-load periods; Nova Scotia about 66% energy; and Utah 25% energy, just to name a few I happen to be familiar with. Various jurisdictions derive these percentages from a number of specific methodologies (the equivalent-peaker method, probability of dispatch, base-intermediate-peak designations, and others). These methods consider the importance of energy on a plant-by-plant basis.

Under the equivalent peaker method, the demand- or reliability-related portion of the cost of each generation unit is estimated as the cost per kW of a peaker (usually a simple-cycle combustion turbine) installed in the same period times the effective capacity of the unit. The cost of the unit in excess of the equivalent gas turbine capacity is energy-related. Due to higher forced-outage rates, lengthy maintenance shutdowns, and the size of units (such as PREPA's Aguirre 1 and 2 and Costa Sur 5 and 6), a kilowatt of steam-plant capacity typically supports less firm load than a kilowatt of capacity from a small peaker.

In contrast to these methods, PREPA considers the fixed costs of the generation sources that contribute to system reliability to be incurred solely to meet peak demand. Following this outdated view of cost causation, PREPA classifies the "fixed" costs of generation plant (debt payment, depreciation, operating and maintenance costs) and the "fixed" charges for IPP as 100% demand-related.

The only generation costs that PREPA recognizes as energy-related are its hydro plants, the cost of purchasing wind and solar energy from independent power producers. Since the hydro generation is run-of-the-river (*i.e.*, the power is available only to the extent that there is water flowing through the dam and energy cannot be stored for use when most needed), PREPA not consider the hydro to provide reliable (*i.e.*, firm) capacity (CEPR-PC-04-09). The solar and wind IPPs are treated similarly. For this reason, PREPA classifies these three types of generation as 100% energy-related (PREPA Exhibit 8.0, page 14).

Some fixed costs of the fossil power plants should be considered energy-related, as described below.

a. PREPA fossil

As I discuss in Section I.E.1.c, PREPA's steam-electric and combined-cycle plants are more expensive to build and maintain than gas-turbine peakers.[47] Those excess costs should be classified as energy-related.

PREPA's filing included $56 million for the Aguirre Offshore Gas Port (AOGP) project and related expenditures for converting the Aguirre steam plant from oil to gas (CEPR-

[47] Or reciprocating engines, as Mr. Zarumba suggests would be the lowest-cost capacity.

PC-02-014). In the IRP order, the Commission limited recovery of the AOGP costs to $15 million in FY2017, pending further analysis of the project's economics. From the IRP, I understand that the purpose of this investment is to reduce fuel costs and to the Aguirre steam plant to operate at a high capacity factor. The fuel-conversion costs should therefore should be classified as 100% energy-related.

The rationale for pollution control costs is similar to that for AOGP. The purpose of pollution controls is to reduce emissions from fossil plants, to allow them to continue burning low-cost fuel at high capacity factors. Peaking units that are only needed in a few high-load hours annually can afford to burn expensive clean fuels, and are often allowed to have higher emission rates, since they operate so little. Hence, need for the pollution controls is driven primarily by the energy-serving function of the other fossil plants.

PREPA explains that "No significant air pollution control costs have been made due to (1) the financial condition of PREPA (2) the company is awaiting the decision on the Integrated Resource Plan" (CEPR-PC-02-13), so the allocation of pollution-control investments would not be relevant to the cost-of-service study for FY2017. Future investments for environmental controls should be treated as energy-related.

b. Fossil power purchases

PREPA's contracts with EcoElectrica and AES are structured with two types of charges: fixed charges in dollars per month that PREPA must pay, regardless of how much energy it takes from the power producer, so long as the plant meets contracted requirements for availability; and variable charges in $/MWh that PREPA pays for the energy it takes.

Navigant proposes to classify the fixed portion (about 44%) of its payments to EcoElectrica and AES as demand-related. (Schedule G-1, G-2, tab Calc-3.1b). Messrs. Zarumba and Granovsky appear to assume that any generation cost that is committed for the rate year should be considered "fixed" and therefore demand-related. (Exhibit 4.0, page 5)

This treatment is not consistent with cost causation. The purchased power agreements with EcoElectrica and AES would not have been the lowest-cost way to meet peak loads. The only rational purpose for PREPA to have entered into these contracts would have been to access lower-priced fuels (coal and LNG) and high efficiency. The fixed portions of the contract payments include the costs incurred to import, store and burn coal and LNG. The excess of those costs, over the fixed charges for a contemporaneous gas-turbine peaking plant, should be classified as energy-related.

2. Allocation of demand-related generation

Typically, utilities allocate demand-related generation based on some form of class contribution to system peak loads, referred to as coincident peak (CP). The loads that determine how much capacity a utility requires may be concentrated in a few hours a year, a few hours in each month, the highest fifty or hundred hours in the year, or some other measure of the loads stressing system reliability. Some utilities skip the classification step and use an allocator for generation that combines peak demands and energy consumption.

Messrs. Zarumba and Granovsky propose a third option, an Average-and-Excess-Demand (AED) allocator, based on a single annual NCP for each tariff code. The standard computation of the AED allocator is fairly simple. It is just the sum of the following two computations:[48]

class share of average demand (which is the same as its share of energy use) × system load factor, plus

the class share of excess demand (peak minus average) × (1 – system load factor).

The AED supposedly reflects energy use, since average load for each class is just annual energy requirement divided by the number of hours (8,760 in a non-leap year). But adding in the excess portion of the allocator (computed as class peak minus class average load), with the weighting of the average and excess portions, result in an allocator that is actually very close to the NCP allocator.[49]

PREPA's use of AED to allocate demand-related generation has several problems. First, Navigant cannot explain what the AED allocator is intended to represent or why a utility might use it. The explanations of the use of the AED from Messrs. Zarumba and Granovsky suggest that they would have preferred to use the CP allocator, if the data were available, and settled for the AED as if it were the only alternative to a coincident-peak allocator (PREPA Exhibit 8.0, p. 17; CEPR-PC-02-01 and CEPR-PC-02-03). In CEPR-PC-02-06, Mr. Zarumba says:

> NCP is not the only appropriate allocator. There are other allocators besides NCP that can be used to allocate generation plant. However, PREPA had limited load research data and, therefore, other allocators (e.g. CP) were unavailable. (CEPR-PC-02-06)

[48] This computation is explained and illustrated with examples in the NARUC Electric Utility Cost Allocation Manual (January 1992), Table 4-10A. Even when I directed Messrs. Zarumba and Granovsky to this explanation in CEPR-PC-02-01, they were unable to correctly implement the standard computation or explain their deviations from the standard method.

[49] Some regulators correct this problem by developing an average-and-peak allocator, which allocates a portion (often the system load factor) on energy and the remainder on peak load, rather than using the excess load. The average-and-peak allocator is usually computed using some type of coincident peak.

As I described in Section II.E.3, Navigant could have developed estimates of class CP contributions in the same manner as it developed estimates of NCP by tariff code. Even once PREPA's consultants gave up on the CP approach, they still had several potential options based on the NCP estimates, including (1) using the annual NCP or the average of monthly NCPs, and (2) using the NCP directly, an AED allocator, or allocators combining the NCP with measures of energy consumption. They made no attempt to provide a rationale for their use of the AED allocator, based on considerations of cost causation.

Second, Messrs. Zarumba and Granovsky calculate the AED allocator incorrectly. They introduced three errors into the computation:

- First, they computed the average demand (Sch. G-1, G-2, Tab Calc-1) as sales ÷ (class annual load factor × hours). Average demand is simply the total number of kWh consumed in the year divided by the total number of hours in the year. Load factor does not belong in the calculation of average demand.
- Second, they increased excess demand, but not average demand, by the ratio of gross to net generation at PREPA power plants, an odd adjustment that inflates one component of the calculation relative to the other.
- Third, they computed "Average & Excess Demand after Correction" as the simple sum of "Average Demand after Loss Adjustment" and "Excess Demand after Adjustment," rather than weighting those demands, respectively, by system load factor and (1 – system load factor). Without the weights, NCP plus excess of NCP over average load (however average load is calculated) would simply be the NCP, but for the previous error.

In response to CEPR-PC-02-02, Messrs. Zarumba and Granovsky acknowledged two errors in its calculation, claimed to have already "reworked the schedule" to correct them, but did not actually provide the revision at that time. In response to CEPR-PC-02-016, they stated that "load factors are no longer applied to energy sales to achieve average demand." Two months later, Messrs. Zarumba and Granovsky submitted a revised COSS that corrects only one error and retains the miscalculation of average demand. With the one correction, the result of Navigant's calculation is a straight NCP allocator, not an AED allocator. (see Sch. G-1, G-2 (Workbook) REV 2016-10-11.xls, Tab Calc-1, Row 71 ("NCP Demand" versus Row 73 (Average & Excess Demand")).[50] It is not clear whether they understand that they have effectively abandoned the AED method.

[50] This supposed correction is not mentioned, let alone explained, in the supplemental testimony (PREPA Exhibit 15.0).

Third, most important, neither the AED nor the underlying annual NCP estimates make sense as an allocator for generation and transmission, since different classes are charged for peaks in different months. As I explain in Section E.3, PREPA's own evidence indicates that all months are equally important; any generation demand allocator should include at least one hourly load from each month, and perhaps more.

PREPA should not be using any AED computation or NCP loads to allocate costs. In the rate-design proceeding, PREPA should do its best to develop estimates of coincident peaks and a CP allocator recognizing the hours that are important in determining capacity requirements. Those estimates should be improved and updated as PREPA develops improved load data.

G. Transmission Allocation

1. Functionalization

As discussed in Section I.E.2, transmission lines are needed both to serve load and to integrate generation. The generation-related portions of transmission equipment—including switching stations, substations and transmission lines required to tie generators into the general transmission network and reinforcements of the transmission system required by remote generation locations and by economic dispatch, are often functionalized as generation.

PREPA identified several switchyards that are required primarily to connect one or more generators to the transmission system, but could not quantify their costs (CEPR-PC-02-026 (Confidential)). Hence, PREPA functionalizes all the transmission investments to transmission.

2. Classification

Navigant classifies transmission as entirely demand-related. For most transmission costs, this approach is reasonable, but some assets that are carried on PREPA's books as transmission may actually be related to interconnecting or integrating generation. Those facilities should be functionalized as generation-related and thus classified in the same manner as the fixed costs of the associated generation. Facilities connecting peakers should be treated as demand-related, those connecting the baseloaded IPPs should be primarily treated as largely energy-related, since the facilities were built to access the IPP energy benefits.

3. Allocation of demand-related transmission

PREPA proposes to allocate transmission on its AED factor, based on estimated NCPs.[51] As with generation, the NCP demand allocator does not reflect the drivers behind transmission costs or the diversity of load on that system. Using any NCP factor (but especially the NCP by tariff code) to allocate transmission costs therefore is not related to cost causation or an equitable allocation of costs

The hours of maximum transmission loads may be different from the hours of maximum generation stress. For example, the power lines from the south shore to San Juan may be most heavily loaded at moderate demand levels, as power from AES and EcoElectrica is shipped north. At high load levels, more of the southern generation is probably used in the south, generation on the north shore increases, and the line loadings may decline. In addition, generator maintenance does not necessarily smooth out transmission reliability risk across months in the same way that it spreads generation shortage risks.

In the rate-design proceeding, PREPA should attempt to develop an allocator based on the hours in which the transmission lines experience their peak loads. If that is not possible in the near term, PREPA can temporarily an allocator based on loads in a large number of hours with high system loads.

H. Distribution Allocation

1. Classification

PREPA classifies all distribution plant as 100% demand-related. Some utilities classify a portion of distribution as customer-related based on a conceptual view that the size of distribution components (e.g., the diameter of conductors, the capacity of transformers) is load-related, but the number and length of equipment are customer-related. This view is overly simplistic. PREPA's is a more realistic approach to distribution classification, for several reasons.

First, much of the cost of a distribution system is required to cover an area, and is not very sensitive to either load or customer number. The distribution system is built to cover an area, because the total load expected to be served will justify the expansion. Serving many customers in one multi-family building is no more expensive than serving one commercial customer of the same size, other than metering. The distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers.

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[51] As I discuss above, due to a mathematical error, Navigant's so-called AED allocator is actually just an NCP allocator.

Second, load levels help determine the number and type of units, as well as their size. In many situations, additional conductors are added to increase capacity, rather than to reach an additional customer. For example, as load grows, utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line, to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder, to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase.

Similarly, the number of poles does not vary with the number of customers. As PREPA acknowledges, "[i]f an additional service is added into an existing street with electrical service, there is usually no need to add additional poles" (CEPR-PC-02-036) and "it would not be reasonable to assume any pole savings if the number of customers had been reduced by half." (CEPR-PC-02-037)

Third, load can determine the type of equipment installed, in addition to size and number. Electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles).

While distribution costs are driven by load levels, the maximum load on each piece of equipment is not the only important load. As explained in in Section I.E.3, increased energy use, especially at high-load hours and prior to those hours, can also affect the sizing and service life of transformers and underground lines is driven by the energy use on the equipment in high-load periods. PREPA does not classify any portion of distribution costs as energy-related or use a demand allocator that recognizes the effect of multiple hours of high use on distribution costs.

In the rate-design proceeding, PREPA should develop a distribution allocator that reflects load in the periods in which the peak loads occur on the distribution substations and feeders, as well as the near-peak and pre-peak loads that contribute to thermal overloads on that equipment. .

2. *Subclassifying distribution costs*

One important issue in cost allocation is determination of the portion of distribution cost that is related to primary service (the costs of which are allocated to all customers, except those served at transmission voltage) as opposed to secondary service (the costs of which are borne solely by the secondary-voltage customers—residential, GSS, streetlighting, etc.).

PREPA recognized that "the ideal situation will be to segregate accounts between Distribution Primary and Distribution Secondary voltage services." (CEPR-PC-02-

031_Attach 01). However, the Company does not keep records of distribution plant cost by voltage level. Instead PREPA provided an aggregate estimate of the percentage breakdown of distribution costs:

> PREPA's plant accounting information does not maintain distribution plant for primary and secondary voltages. However, the PREPA planning department provided Navigant with a ratio of 59.5% for Primary and 40.5% for Secondary, which was subjectively determined for distribution costs that were not directly assigned to secondary voltage (i.e., line transformers). (Exhibit 8.0, p. 14) [52]

Navigant applied this single factor to all distribution system costs from substations to lines and poles (except line transformers).

Navigant's use of this ratio presents two basic problems. First, Navigant presented this ratio as an estimate of the percentage of distribution cost that is secondary *equipment*. It turns out that the ratio that PREPA provided is an estimate of the secondary portion of total distribution *load*, which Navigant took to be equivalent to the secondary portion of costs.

PREPA estimated that 40.5% of distribution NCP load is served at secondary. PREPA then assumed that, for secondary customers, the secondary system cost as much per kW of load as the primary system, and hence that the 40.5% of NCP served at secondary should pay for 40.5% of the system as the assumed cost of secondary, plus 40.5% of the 59.5% of the distribution cost at primary, or 65% of the distribution costs, resulting in secondary customers being assigned 2.7 times as much as primary customers, per kW of NCP (CEPR-PC-02-31). This is an arbitrary basis for functionalization; there is no reason to expect that that costs of primary and secondary service would match loads.

Second, the primary-secondary cost breakdown differs by distribution component. PREPA did make an exception from its generic 40.5%/59.5% split for the Line Transformer account because it can be "directly associated…[with] a specific voltage level service." (CEPR-PC-02-31). Since the purpose of line transformers is to step down voltage from primary to secondary level, PREPA appropriately charges line transformer costs to secondary customers only. However, PREPA overlooked two other components that can also be directly associated with a specific voltage level: costs of both substations and poles are driven by demand at the primary level. PREPA should allocate both of these capital accounts and associated operations and maintenance based on primary loads.

[52] The Secondary Only portion changed from 40.5% to 41.8% in the Revised COSS Zarumba presumably as a result of the change in the calculation of Tariff GSP (212) NCP (PREPA Exhibit 15.0, p. 13; Sch. G-1, G-2 (Workbook) REV 2016-10-11, Tab "Calc 2.1"). PREPA's estimate of the costs of its equipment should not vary with its assumptions about loads.

The cost-of-service study model that Navigant created for PREPA is constructed so that the subfunctionalization of distribution plant accounts between primary and secondary essentially requires that a single ratio be applied to each distribution accounts other than line transformers. (Schedule G-1, G-2.xls, Tab Calc-2.1) The model can accommodate different primary/secondary ratios for different type of equipment only if the relationships are manually traced through cell-by-cell, formula-by-formula to make sure all associated costs are changed in concert with a change in inputs. Even Messrs. Zarumba and Granovsky do not seem to know how to make such a change to their own model. When asked to treat all substation costs as primary distribution, Mr. Granovsky responded "Unfortunately, substations are not a line item on the distribution revenue requirement" and could not perform the computation (CEPR-PC-07-23b).

For the rate-design proceeding, PREPA should develop a cost-based estimate of the division of costs between primary and secondary equipment. PREPA can easily identify several accounts as being either due to primary load (substations, poles) or secondary load (line transformers), but may not have the data necessary to subclassify conductors, and may need to develop an estimate based on typical configurations. In the longer term, PREPA can develop better data, perhaps in conjunction with the rebuilding of failing feeders.

a. Substations

Distribution substations take power off transmission and feed it into the distribution system at primary voltage. All distribution substations deliver only primary power, and therefore should be classified as 100% primary, as opposed to PREPA's classification of 40.5% of substation costs as secondary-related.

b. Poles

Poles should also be functionalized as 100% primary. Nearly all poles carry primary lines and the incremental pole cost for adding secondary lines to a pole carrying primary is often negligible.[53] PREPA confirms that secondary service adds little to the cost of poles that carry both secondary and primary lines: "If a pole [that] is currently [used] for both secondary and primary lines had its secondary lines removed, the difference or reduction in costs would be very small. Equipment used in holding secondary lines has a very low cost compared to those used for primary lines." (CEPR-PC-02-031, d and e). Furthermore, the small number of poles that are secondary-only replace primary poles at lower cost, as explained in Section II.C.2.

[53] Secondary-only poles are usually shorter and skinnier than primary poles, which typically also require cross-arms. Where only secondary lines are needed (for the last couple pole spans at the end of a street, for example), PREPA would save on pole costs due to the customer taking secondary service, rather than requiring primary supply and a bigger pole.

3. Distribution demand allocators

Class NCP is commonly used for demand allocation of distribution costs. This allocator would be appropriate if each component overwhelmingly served a single class, and if the equipment peaks occurred roughly at the time of the class peak. PREPA's use of NCP by tariff code takes this treatment a step further; it implicitly assumes that each piece of distribution serves only one tariff code.

These conditions do not actually apply to PREPA's system, for the following reasons:

- Most substations and feeders serve several tariffs, in different classes, and many tariff codes. (CEPR-PC-02-029)
- Customers in a single class, in different area and served by different substations and feeders, may experience peak loads at different times.
- The peak months for substations do not align with the months at which Navigant estimates the class NCPs.

Table 2: Distribution of Peak Loads By Month (% of MW)

	Substation Annual Peaks	PREPA Estimates of Tariff-code NCPs
Jan	4.6%	0.01%
Feb	3.7%	6.2%
Mar	3.6%	-
Apr	8.8%	0.1%
May	4.4%	-
Jun	3.9%	0.8%
Jul	6.6%	2.1%
Aug	20.9%	0.1%
Sep	10.8%	17.3%
Oct	22.1%	68.6%
Nov	4.5%	4.8%
Dec	6.1%	-

In the rate-design proceeding, PREPA should estimate the contribution of each class to the hours when load on the substation and feeder is highest. The resulting allocator should reflect the variety of seasons and times at which the load on this equipment peaks. In addition, the allocator should reflect the near-peak and pre-peak loads that contribute to overheating and aging of equipment. Selecting the important hours for distribution loads and the weight to be given to the pre-peak loads may require some judgments.

PREPA needs to develop additional information on its system loads for cost-allocation, planning, operational and rate-design purposes. Specifically, it needs to understand when each of its feeders reaches its maximum loads and the mix of rate classes on each feeder and distribution substation.[54]

Once PREPA has more reliable customer load data, it can develop a more appropriate allocator for distribution costs, such as the distribution classes contribution to load at the times of substation peaks.

I. Allocation of Customer-Classified Costs

PREPA classifies the following costs as 100% customer-related costs: service drops (the lines from the street to the customer), meters, customer installations, meter O&M, and customer billing expense (Schedule G-1, G-2,Tabs Calc-2.2 and Calc-3.1b). Navigant allocated each of these costs based on a weighted number of customers. It based the weights on estimates of the relative cost of the meter by tariff code (Schedule G-1, G-2,Tab G-5e). As explained by Messrs. Zarumba and Granovsky, the utility incurs higher customer costs to serve higher-use customers:

> A weighing approach was adopted as an average residential customer generally uses less customer-related facilities (i.e., an individual residential customer does not have nearly the same billing expense as a large industrial customer). The weighing factor chosen was meter costs, as meter costs for larger customers are higher than for smaller customers. (Exhibit 8.0, p. 19)

PREPA refers to this weighted customer allocation factor as the "Client allocator," as shown in the following table for a sample of tariff codes. A weighted customer factor can be an appropriate method for allocating customer-related costs. For example, the cost of a customer's service drop clearly varies with a number of factors that differ by class: customer load (which affects the capacity of the service), the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service (or the number of services required by a single customer),[55] and whether customers require 3-phase service.

However, PREPA's approach has three problems. First, PREPA was not able to provide the derivation of the relative meter costs. In response to CEPR-PC-11-01, Mr. Zarumba points to his marginal cost study as the source of the values used in the cost-of-service study, but its relative meter cost weights in the two reports are not consistent, as shown in Table 3. The marginal cost study provides cost estimates for single-phase and three-phase secondary meters, and for two types of three-phase primary meters. Somehow, Mr.

[54] PREPA does not have data on the loads on feeders (CEPR-PC-02-030).

[55] The number of services is smaller than the number of customers in the residential class (and to some extent small commercial), since several customers can share a service drop in multi-family housing and some commercial buildings.

Zarumba derived meter charges for transmission and streetlighting customers without input from the marginal-cost study, and derived primary meter weights lower than the range of primary weights in the marginal-cost study.

Table 3: Meter-Cost Weights in the Cost-of-Service Study and Marginal-Cost Study

			In MCS	
Tariff Code	**Voltage**	**In COSS**	**Low**	**High**
PLG 423	S	0.86		
PLG 421	S	0.97		
Residential	S	1.00	1.0	
PLG 424	S	1.02		
PLG 422	S	1.07		
GSS 211	S	1.15	1.0	2.0
LP-13 414	S	1.33	1.0	2.0
GAS 711	S	1.34	1.0	2.0
GSP 312	P	1.41	1.6	2.0
GSP 212	P	1.43	1.6	2.0
GSS 311	S	1.45	1.0	2.0
TOU-T 363, 643,653	T	1.48		
GST 313	T	1.51		
GST 213	T	1.52		
TOU-P 862	P	1.57	1.6	2.0
LIS 333, 663; 673	T	1.57		
TOU-T 963, 393, 623, 633	T	1.57		
GST 513, 603, 613	T	1.57		
PPBB 343	T	19.67		

In addition, the marginal-cost workpaper (at Calc-5 in the updated version), uses a different set of weights for billing and meter expense than for meters, with primary costs at 9.4 to 9.8 times the residential cost. Again, the marginal-cost study is inconsistent with the cost-of-service study and indicates that the cost-of-service study erred in the use of a single set of class weights for all customer costs.

Second, Navigant has not provided any support for assuming that a weighted customer allocator based on relative meter costs is an appropriate allocator of other customer costs. There is no reason to expect the variation in the average cost of a meter to be a good measure of the difference among classes in other average customer costs. For example, the variation in the average cost of a service drop among classes depends on a number of factors that have nothing to do with the cost of meters—the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service drop—and others that may have very different effects on meters and service drops, such as load and 3-phase service.

Third, the number of services drops is smaller than the number of customers in the residential classes (and to some extent small commercial classes), since several customers can share a service drop in multi-family housing and some commercial buildings. No adjustment to the allocation of services for the number of customers sharing a service, or the number of services lines required by a single large customer (CEPR-PC-02-045, 02-47).

J. Overheads

Overheads are costs that cannot be directly assigned to particular functions. In the category of overheads, I include the capital costs that PREPA records as General Plant in Accounts 389-399 (which includes office buildings and warehouses) and the O&M expenses that PREPA records as Administrative and General (A&G). (Sch. G-1, G-2, Tabs 8.04 and Input-2). The cost-of-service study provides a breakdown of General Plant by account, but does not do the same for A&G. PREPA has not considered the mix of A&G expenses, and what causes each of them.

Some of the A&G accounts in the standard utility accounting systems serve a single function and are driven by a single factor. For example, pension expenses and other employee benefits vary with the number of employees and/or salaries.

On the other hand, many of the standard A&G accounts serve multiple functions. Administrative salaries pay employees in human resources, financing, public relations, regulatory affairs, the law department, purchasing, and senior management. Some of their work is driven by employee numbers (e.g., human resources), others by capital investment (finance), and most by a mix of labor, fuel procurement, non-fuel expenses, and capital investments, including dealing with disputes with suppliers, customers, regulators and other parties. Purchased services may include consultants on new power plants, fuel and equipment procurement, power transactions, environmental compliance, worker safety, and many other activities.

Rather than consider these overhead costs separately on an account-by-account basis, which is the approach typically used by utilities, Navigant functionalized and classified General Plant and A&G on a single labor factor, ignoring how overhead costs support all other aspects of utility operation. (Schedule G-1, G-2, tabs Calc-2.2 and Calc-3.1b).

PREPA acknowledged that not all A&G expenses are related to labor and that:

- some expenses are related to plant, such as insurance and finance (CEPR-PC-02-052)
- factors that drive PREPA's legal expenses including "regulatory matters, environmental issues, licensing issues, legal opinions, local legislative requests and evaluations, eminent domain, general lawsuits, among others," which are not clearly related to labor. (CEPR-PC-02-053)

Nevertheless, Navigant declined to provide a justification for classifying each Administrative and General Expenses account based on labor and simply alleged that "Labor ratios are a generally accepted approach to cost allocation" (CEPR-PC-02-051).[56] PREPA should revise its cost-of-service study to functionalize and classify overheads on an account-by-account basis.

Navigant did break out one A&G expense, the Energy Commission assessment, for separate consideration in the cost-of-service study, but classifies this cost improperly. Utilities normally include regulatory commission expenses as an overhead and spread it over an allocator that reflects the benefits of regulation. PREPA classified the Commission assessment as 100% customer-related (meaning the assessment is based on the number of customers), giving the following rationale:

> The justification for functionalizing the PREC Assessment as 100% Customer and allocating…that cost using the Client allocator is based upon the assumption that all customers equally benefit from the oversight of the PREC. (CEPR-PC-02-57)

The benefits of the Commission's oversight will be distributed more in proportion to the classes' total bills than to number of customers in the classes. In terms of cost causation, the PREC Assessment covers expenditures on many types of proceedings before the Commission, including rate cases, Integrated Resource Planning, review of generation plant investment and power purchase contracts, and the Fuel-Purchase Adjustment Clause. Demand and energy use are the major contributors to the size of the assessment and the cost of its regulatory efforts.

The Commission assessment should be allocated on revenues, or a close proxy, such as energy.

K. Treatment of CILT and Subsidies

The Legislature or PREPA have instituted a number of provisions that provide bill discounts or credits to various groups of customers. The decision to reduce the revenue responsibility of some customers increases the revenue responsibility of other customers. PREPA recognizes the allocation of free electricity to municipalities as contributions in lieu of taxes in the CILT charge and about 14 other discounts in a subsidy charge. These are described in detail in Section V.

The cost-of-service study recognizes the need to recover subsidies, and adds a subsidy cost to the revenue responsibility of each class. PREPA even allocates CILT and subsidies to classes (LRS, RH3, and RFR tariffs) that it proposes to exempt from the

[56] While labor is an appropriate factor for functionalizing or allocating some overhead costs (*e.g.*, pensions, payroll taxes and employee benefits), it is not a suitable allocator for all overhead costs.

subsidy and/or CILT charges in the rate-design process. If PREPA does not believe that these tariff classes should be paying those costs, allocating the costs to those tariffs results in a confusing cost allocation that is not a useful guide to revenue allocation.

While PREPA allocates the costs of CILT and the subsidies over all classes, it does not similarly allocate the benefits of those subsidies to the recipient classes. Table 4 shows how the cost-of-service study could reflect the intended reduction in revenue recovery for each tariff with subsidies. This example just shows PREPA's summary of the cost allocation to each of the residential tariffs, from Schedule G-1 REV 2016-10-11, Calc 5.2. I have added a line reflecting the intentional transfers of costs that PREPA has identified for each of the tariffs (the RH3, RFR, and LRS discounts, the life-preserving equipment discount, the fuel subsidies, and direct-deposit discount). These costs are transferred to from these specific tariffs to the subsidy account that is allocated across all customers.

Table 4: Correction of PREPA Class Revenue Requirement for Subsidies

Classification:	RH3	RFR	LRS	GRS
Production Energy	$1,451,156	$16,940,982	$39,147,501	$366,474,489
Production Demand	$1,380,651	$17,025,087	$33,964,830	$324,229,988
Transmission Demand	$372,358	$4,591,623	$9,160,229	$87,444,006
Distribution Demand - Primary	$485,475	$5,986,484	$11,942,960	$114,008,101
Distribution Demand - Secondary	$589,481	$7,269,006	$14,501,574	$138,432,757
Customer	$1,084,005	$6,542,688	$27,363,644	$179,383,811
Contributions (CILT and Subsidies)	$269,467	$3,145,796	$7,269,358	$68,051,194
Other Income	-$50,042	-$584,202	-$1,349,984	-$12,637,708
Direct Assignment	$10,634,579	$25,731,367	$2,984,692	$17,437,359
PREPA-reported Requirement	$16,217,129	$86,648,830	$144,984,804	$1,282,823,999
Transfers	**-$1,406,384**	**-$20,076,641**	**-$24,942,245**	**-$11,398,515**
Corrected Revenue Requirement	**$14,810,745**	**$66,572,188**	**$120,042,559**	**$1,271,425,484**

Table 4 includes only the residential tariffs, but The same approach could also be applied to the CILT and subsidies received by various customers in the commercial classes, the tax credits in the industrial classes, and the subsidies received by public streetlighting and unmetered classes.

PREPA's task of tracking discounts to classes might be easier if it added a tariff code for each rebate, so it could separately report the sales and revenues from churches on the analog rate (who are charged the GRS tariff rather than the GSS tariff that would normally apply), hotels receiving the hotel discount, residential energy in each class provided under the life-preserving equipment subsidy, and so on.

L. Miscellaneous COSS issues

1. Transmission use by the PPBB class

The PPBB (Power Producer Bus Bar) tariff supplies AES and EcoElectrica with power during planned maintenance and unplanned outages. PREPA claims that it can provide service to the PPBB customers without transmission and therefore does not allocate any transmission costs to that class. The best explanations I have been able to get from PREPA on this point are as follows:

> PREPA provides service to these two customers at bus bar voltage (230 kV). These are the cogenerator backup electrical service, not by definition a transmission voltage service. (CEPR-PC-04-03)
>
> Depending on the location of the PPBB, service can be provided to the delivery point without external transmission, since they are connected to the 230 kV generation bus. (CEPR-PC-10-04a)

PREPA has not explained how it could deliver that energy at 230 kV without the transmission system, or why "backup electrical service [is] not by definition a transmission voltage service."[57] On its face, the PPBB customers receive service at transmission and should pay their share of transmission capacity. While this problem has less effect than several of the other errors in the cost-of-service study, it is yet another example of why the Commission cannot accept the PREPA cost-of-service study.

In the rate-design proceeding, PREPA should either include the PPBB class load in the allocation of transmission costs, or provide a more convincing rationale for the special treatment of this tariff class.

2. Allocation of debt service

a. Functionalizing debt service

Most utilities compute the revenue requirements associated with investments in plant and equipment by (1) collecting the investment over the life of the investment, through depreciation and (2) charging an annual return on the unrecovered balance, at the utility's cost of capital. The total investment is called *gross plant*, and the gross plant minus accumulated depreciation is called *net plant*.

Different types of utility plant have different useful lives, and the mix of gross plant across functions is usually different than the mix of net plant across functions. Cost-of-service studies usually functionalize depreciation expense in proportion to the mix of gross plant and functionalize return in proportion to net plant.

[57] The only power that can be delivered to these plants at their 230 kV buses without the use of PREPA generation would be from the plant itself.

PREPA's cost-of-service study does not include separate expenses for depreciation and return, but combines those items into a single item called debt service, to reflect PREPA's cash requirements. The magnitude of the debt service includes the repayment of bond principal (akin to depreciation) and the payment of interest (return). Debt principal is typically amortized over the life of the investment, so the amount of debt outstanding is proportional to the net book value of the plant. Logically, debt service should be functionalized partly on gross plant and partly on net plant.

PREPA functionalizes legacy debt entirely in proportion to gross plant, which is inappropriate.

PREPA does not appear to have organized its plant records in a manner that would allow it to estimate accumulated depreciation (or debt repayment) by function. In the rate-design proceeding, the Commission should determine whether correcting this error is possible with a reasonable level of effort.

b. Misallocation of the transition charge

The Commission approved the calculation methodology Transition Charge in Docket No. CEPR-AP-2016-0001, requiring that the charge be recovered as a uniform ¢/kWh charge (initially 3.1¢/kWh) from all customers other than the RFR tariff fixed blocks and grandfathered net-metering customers. The allocation of the Transition Charge among classes is required by law to be "based on historical kWh usage of each class" (Section 6.25A(d)(1) of Act 57-2014). PREPA proposes to charge the same Transition Charge per kWh of sales to all tariffs in Schedule M-3 (excluding deliveries to municipalities under the CILT program).

Yet in the cost-of-service study, PREPA functionalizes the transition charge in proportion to gross plant and hence allocates costs differently to different tariff classes. The resulting allocation of costs ranges from 1.2¢/kWh for GST to well over 4¢ for some residential rates and over 10¢/kWh for some lighting tariffs. While the actual bills for all customers would show the same Transition Charge rate, the cost-of-service study would understate the assignment to some tariffs (such as GST), and understate the allocation to other tariffs.

3. Other income

PREPA allocates other income in proportion to energy consumption. PREPA says that "Other Income…consists of items such as non-operating rental income, sinking fund interest income, and other miscellaneous non-operating income" (CEPR-RS-03-07h). I assume that it also includes fees on customers (such as connection fees). The rental income may include rental of unused buildings and land, as well as rental fees on PREPA's poles and other structures for cable companies, cellular phone antennae, and the like. The fees should be allocated to the tariffs (or at least classes) that pay them, and the rental fees should be credited to the classes that pay for the equipment that is rented out (e.g., distribution load should be credited with cable connection fees). Sinking fund interest (an offset to debt service) should be allocated in the same manner as debt service.

M. The Task Ahead

As described throughout this section, PREPA's cost-of-service study is so badly flawed that the Commission cannot determine whether cost-causation considerations would justify any aspects of PREPA's proposed allocation of the revenue increase.

PREPA has a large amount of work to do before it will have a cost-of-service study on which the Commission can rely to guide revenue allocation—one whose methodologies are consistent with best practice of North American utilities—with variations appropriate for PREPA's unique characteristics. Some of those changes, such as tracking revenues and subsidies more accurately, or allowing changes in classification to flow through to all subsequent computations, are relatively simple, even though correctly modifying a workbook as complicated as the cost-of-service study requires some care and quality control.

Other changes will require some greater effort, to apply information that PREPA already has to the development of improved classification and allocation factors. Examples in this category would be the breakdown of the A&G expenses by account and determination of an appropriate classification and/or allocator for each group of expenses; classifying fixed generation costs between demand and energy; and determining the hours that contribute to the need for generation, transmission and distribution capacity. A serious analysis of the portion of distribution plant attributable to secondary lines might also be in this category.

Even more work would be required to determine the class contributions to load in the hours that drive generation, transmission and distribution capacity. For most tariffs, PREPA has some sort of hourly load data for some year, although there are a few tariffs for which PREPA has not been able to provide a full year's worth of data. Over a few months, PREPA may be able to develop rough estimates of the class contributions to critical hours, based on the available data. Developing a fully-consistent, statistically valid load shape for each tariff will require over a year from the time that the Commission instructs PREPA to start the process of sample selection, structuring daily meter reading, recording a year's worth of data, and analyzing those data.

Even under favorable conditions, regulatory review of a cost-of-service methodology that has not been reviewed in many years is a time-consuming process. For example, the Nova Scotia Utility and Regulatory Board started a review of Nova Scotia Power's cost-of-service methodology in 2012, for the first time since 1995. Including stakeholder consultation and adjudication, the process took until March 2012, when the NSUARB issued an order in the proceeding. Even that order recognized that several important issues needed to be resolved by additional data collection and analysis, including the capacity value of wind resources, sub-functionalization of distribution between primary and secondary, review of the load research program and line loss determination. Additional consultations and interim reports continued through 2014 into 2015. Nova Scotia Power has not filed a rate case since that review (and now is not allowed to file a rate case until 2019), and has not submitted the required supplemental analyses, probably because the cost-of-service study is not a particularly high priority.

III. Revenue Allocation

While the purpose of the cost-of-service study is to estimate the amount of costs that might equitably be considered to be causally related to the characteristics of each tariff class, the revenue allocation actually specifies the portion of the revenue requirement that would be recovered from each tariff. While a good cost-of-service study can be a valuable input to the revenue allocation, the cost-of-service results are just one consideration in determining the revenue allocation. For example, while PREPA appears to be comfortable that its cost-of-service study provides useful information, its proposed revenue allocation bears little relationship to the cost-of-service results.

Given the flaws in the cost-of-service study, the revenue allocation should not be driven by the cost-of-service study. Without a useful cost-of-service study, the Commission must find other approaches to determining the revenue allocation, as I discuss below.

A. PREPA's Proposed Revenue Allocation

In various documents, PREPA presents its proposed percentage rate increases in several ways and is not always careful to explain how it computes those increases. The existing revenues can be defined to include only the existing base rates, or also fuel and purchased power charges (at the level in effect in FY2014 or projected for FY2017), which include the adder for CILT and subsidies, or all of the preceding plus the already-approved transition charge. The proposed revenues can be defined to include only the existing base rates; base rates plus the CILT and subsidy charges; base rates plus CILT, subsidies, fuel and purchased-power charges; or all of the preceding plus the transition charge.

In order to be meaningful, the comparisons must be between comparable scope of charges; existing base rates without CILT or subsidy costs should not be compared to proposed rates with those costs. It is also important to understand whether a percentage increase applies only to the base rate or to some much larger revenue base.

Table 5 summarizes PREPA's proposed increases in retail rates by customer class. The percentages reflect the retail revenue increases (excluding the transition charge), divided by the existing total rates (base, FCA and PPCA, also excluding the transition charge).

Table 5: PREPA Proposed Increases in Total Retail Rate Increases

	Original Proposal	Revised Proposal
Residential	9.5%	8.9%
Commercial	4.5%	3.9%
Industrial	4.5%	3.9%
Other Public Authorities	4.5%	3.9%
Agriculture	4.5%	3.9%
Public Lighting	66.7%	86.6%
Total	8.1%	8.1%

Sources:
Original: PREPA Exhibit 12.0, p. 5
Revised: Schedule M-3 REV 2016-10-11b, Tab 'Mitigation', Row 73

The rate increases requested for individual tariffs vary within the broad rate classes, as shown in Table 6. The three computations compare the following revenues by tariff:

- Proposed base rates (net of fuel and purchased-power costs) versus existing base rates.
- Proposed total retail rates, including the proposed CILT and subsidy charges, and 8.547¢/kWh of fuel and purchased-power costs versus existing total rates, including the 8.547¢/kWh of fuel and purchased power, with the CILT charge that would be collected with that level of fuel and purchased power.
- Total rates, adding the transition charge to both the proposed and existing rates.

With a higher and more realistic estimate of fuel costs, the percentage increases in total retail rates and total rates would be lower than shown in Table 6.

Table 6: PREPA Proposed Final Increases by Tariff

		Proposed Increase		
Tariff Class	**Rate**	**Base Rates**	**Total Retail Rates**	**Total Rates**
Residential	GRS	23.3%	9.6%	8.1%
Residential	RH3	57.2%	3.5%	2.8%
Residential	LRS	50.6%	4.6%	3.7%
Residential	RFR	7.4%	7.4%	7.1%
C/I/OPA	GSS	6.0%	3.8%	3.3%
C/I/OPA	GSP	3.8%	3.1%	2.6%
C/I/OPA	GST	.8%	2.9%	2.4%
C/I/OPA	TOU-P	41.9%	16.4%	13.6%
Industrial	TOU-T	14.1%	7.0%	5.6%
Industrial	LIS	4.8%	4.1%	3.3%
Industrial	PPBB	23.5%	22.2%	21.7%
Industrial	SBS	74.0%	28.5%	23.3%
Commercial	CATV	6.3%	3.8%	3.3%
Commercial	USSL	4.9%	3.8%	5.0%
Agriculture	GAS	6.2%	3.8%	3.2%
Lighting	LP-13	184.3%	88.4%	83.1%
Lighting	PLG	133.5%	88.4%	98.4%
System Total		17.1%	8.1%	6.9%

C/I/OPA indicates that tariff serves the commercial, industrial and other public authorities classes

Data computed from Schedule M3 (Revision b Oct, 2010), Tab 'Rate Design'.

Of all these proposals, the only one that Navigant specifically justifies is for public lighting.

> Public Lighting tariffs were moved to Full Cost of Service. Public Lighting is a subsidized class, and therefore required a redistribution of the overall revenue requirement. Therefore, adverse customer impacts are artificially high. (PREPA Exhibit 4, p. 25)

Since the public lighting tariffs are used primarily by municipalities, who do not pay for public lighting services, increasing these rates will increase the computed revenue that the municipalities will not be billed. PREPA includes the lighting provided to municipalities in the subsidy charge, so increasing with public lighting rates will increase the magnitude of the subsidy charge, shifting costs back to other customers. PREPA agrees that higher public lighting rates will translate into higher subsidy rates, rather than increasing actual revenues from public lighting customers. (CEPR-PC-11-02) So PREPA's proposal will shift base-rate revenues from other classes to the public-lighting tariffs, which will then flow back to other classes in the subsidy charge.

PREPA has not explained why this shift of revenues from base rates to the subsidy charge is desirable, or even quantified the effect on the subsidy charge. A small portion of the public lighting sales go to non-municipal customers, who are actually billed for their service and will bear the "artificially high…adverse customer impacts" that Navigant foresees.

I recommend that the Commission deny this dramatic increase in the public lighting rates, unless PREPA provides a compelling justification for it in the hearing.

B. Options

Given the serious deficiencies in PREPA's cost-of-service study, as well as the gaps in its underlying data, the development, full review and approval of a suitable cost-of-service study is not practical in this proceeding. It is not clear that PREPA's filed cost-of-service results have any significance. Hence, the Commission must decide how to allocate revenues in this proceeding on some other basis. Faced with inadequate or inconclusive cost-of-service analyses, regulators frequently allocate revenue increases on an equal percentage basis across tariffs. In the absence of a demonstration that the revenue allocation to some particular tariff can be determined to be inequitable, unfair, or unreasonable, there is no basis for assuming that a change in the allocation pattern would represent an improvement. That would be a reasonable approach for the Commission to take in this proceeding, while moving to improve the available analyses in the upcoming rate-design proceeding.[58]

An alternative approach, which the Commission employed in setting the provisional rates, would be to increase base rates for each tariffs by the same ¢/kWh value. This pathway requires fewer methodological decisions and is independent of the quality of PREPA's data.

Nor is the Commission limited to equal changes across all tariffs, where there is some clear reason to vary from its selected revenue-allocation approach. I have identified two tariffs for which such a deviation may be.

First, the average revenue per kWh for the non-subsidized GRS tariff is low, compared to the revenue per kWh for the general-service classes. Table 7 summarizes PREPA's

[58] An equal percentage increase could be applied to a number of different revenue levels by tariff class. The starting point would certainly include the base-rate revenues (perhaps reduced for net-metering credits), but could also include the CILT and subsidy charges, charges for purchased-power and fuel (at the level anticipated in the filing, or updated), and even the anticipated transition charge.

estimates of FY2017 revenues under existing rates for the standard residential tariff (GRS 112), and the general-service (non-residential) secondary, primary and transmission tariffs, computed from WP-1 (Billing Determinants) REV 2016-10-11.

Table 7: PREPA Estimates of Average Existing Rates, Major Tariffs ($/kWh)

Tariff and Code		Existing Rates	Δ from GRS
General Residential	**GRS 112**	$0.268	
GS Secondary	**GSS 211**	$0.297	$0.029
GS Primary	**GSP 212**	$0.275	$0.007
GS Transmission	**GST 213**	$0.228	-$0.040

The relative prices of the three general-service tariffs make sense. Primary service requires distribution substations and feeders, while transmission service does not. Secondary service also requires line transformers and some secondary lines. The transmission customers tend to be larger than the primary customers, who in turn are typically larger than secondary customers. As a result, costs as services, meters, and billing (while they may be higher for the larger, higher-voltage customers) are spread over more energy per customer, contributing less cost per kWh.

Depending on load shapes, the costs of serving residential loads at secondary could be higher or lower than the costs of serving general-service loads at secondary.[59] I reviewed the average monthly revenue per kWh from about 300 utilities in states without general direct access for competitive power suppliers.[60] About 24% of the reports showed the average residential to be lower than the average commercial rate; since most of those utilities probably included some primary (and perhaps even transmission) load in the commercial class, it does not appear uncommon for residential rates to be lower than general-service secondary rates.

It is less likely that the cost of serving residential load would be lower than the cost serving primary load. Hence, equity would likely be furthered by increasing the revenue allocation to the GRS class (and hence to the other residential classes that use the GRS tailblock) by a few mills more than the system average, to gradually move the GRS toward the GSP rate.

The other tariff that justifies special treatment is the PPBB tariff, the a rate for back-up service to the two large fossil power producers, and recovers most of its revenue through demand charges. Allocating the revenue increase on energy would result in the PPBB

[59] Some costs tend to be higher per kWh for serving residential customers (and especially single-family homes) than the larger secondary general-service loads.

[60] I used monthly revenue and sales from the Energy Information Administration’s Form EIA-826 detailed data for 2015.

almost entirely avoiding the increase. Hence, if the general revenue allocation is based on an energy rate, the PPBB rates should be allocated an increase based on its share of total revenues. [61]

C. Recommendation

For simplicity, I recommend that the revenue increase from PREPA's expected revenue in FY2017 under current rates to the FY2017 revenue requirements be allocated primarily on an equal cent-per-kWh basis with two exceptions. Prior to the computation of the general cent-per-kWh increase, I recommend that Commission require that PREPA make two other changes:

- Increase the PPBB revenue requirement by the average increase in the system revenue requirement, excluding the fuel, purchased-power and transition charges.
- Increase the GRS revenue requirement by $3/MWh (0.3¢/kWh).

The remainder of the allowed revenue increase would then be divided by projected FY2017 sales to yield a general cent-per-kWh revenue increase rate. The revenue allocation for each tariff would be increased by the tariff sales times the revenue increase rate.

IV. Marginal Cost Study

A. Marginal-cost Overview

1. Role of the marginal-cost study in ratemaking

The purpose of a marginal cost study is to estimate the costs of:

- serving one more customer, for each of the various types of customers served (with single-phase and three-phase service; at transmission, primary or secondary voltage; for various size connections, and/or with various types of metering);
- generating or purchasing one more kWh of energy at various times, plus the line losses associated with delivering the energy to the customer;
- providing enough generating capacity to serve another unit of customer load (e.g., a kilowatt at the coincident peak hour(s)) plus the line losses associated with that load;
- providing enough transmission capacity to serve another kilowatt of the customer loads driving transmission requirements;

[61] A similar, but much smaller, issue arises for the standby rates, which can be addressed in the rate-design proceeding.

- providing enough primary distribution capacity to serve another kilowatt of the customer loads driving primary distribution requirements;
- providing enough secondary distribution capacity to serve another kilowatt of the customer loads driving secondary distribution requirements.

Alternatively, the marginal costs can be stated as the savings from serving one fewer customer or unit. A handful of jurisdictions use marginal costs to allocate costs among classes.[62] Most jurisdictions base their cost allocations on embedded cost-of-service studies, without any reliance on marginal costs.[63] In contrast, marginal costs are widely used as a guide to rate design, providing comparisons between a class's marginal customer cost and its customer charge, or between the energy charge and the marginal costs that the Commission intends be reflected in that charge.

2. *PREPA's marginal-cost study*

PREPA's marginal-cost study (described in PREPA Exhibit 9.0) provides estimates of the cost of additional energy and capacity usage, as a guide to rate design, including:

- setting energy rates (PREPA Exhibit 4.0, p. 34, 41),
- setting customer charges (PREPA Exhibit 15.0, p. 6–7),
- estimating whether net-metered customers are subsidized (PREPA Exhibit 4.0, pp. 34–35),
- justifying the load-retention rider (PREPA Exhibit 4.0, p. 36), and
- setting avoided-cost rates for non-renewable distributed generation (PREPA Exhibit 4.0, pp. 32–33).

The marginal-cost study has some serious deficiencies, including the following:

- Dramatically under-estimating fuel prices, and hence marginal energy costs.
- Ignoring the costs of renewable resources to meet the renewable portfolio standard.

[62] Since the sum of marginal costs times billing determinants will usually vary significantly from the revenue requirement, an adjustment is required to reconcile the marginal costs to total revenues. This reconciliation has some peculiar effects, such as that the allocation of distribution costs to classes varies inversely with volatile marginal energy costs. The fairness of marginal-cost allocation of embedded costs is questionable.

[63] Occasionally, an embedded cost-of-service study will use a marginal cost concept to allocate some cost component, such as determining the relative importance of energy use by season and time of day.

- Assuming that no load-related generation investments are avoidable for 20 years, ignoring PREPA's proposals to add hundreds of megawatts of capacity starting in 2020.
- Assuming that no transmission investments are avoidable for more than 20 years, ignoring PREPA's plans to add large amounts of load-related transmission in the next three years alone.
- Excluding large amounts of load-related distribution investments.
- Assuming that additional distribution plant will not increase O&M.
- A failure to distinguish between average and marginal losses.

Given the number and magnitude of these flaws, review and improvement of the marginal-cost study will require detailed analysis of T&D investments project by project, and should be delayed to the rate-design proceeding.

B. Generation Energy Costs

1. Fuel costs

While the PREPA marginal-cost analysis uses estimates of long-term costs for some components, it computes marginal energy costs only for 2017.[64] Those marginal energy costs are very low. They are much lower than the FY2016 production costs that PREPA reports for its power plants (CEPR-AH-03-07(e)) and appear to be consistent with residual fuel prices around $30/bbl. As discussed by Commission experts Jeremy Fisher and Ariel Horowitz, PREPA's fuel costs for 2017 are likely to be about 70% higher than PREPA estimated in its filing.

I also understand from PREPA's IRP filing that its production-cost modeling assumes that its steam plants will be kept on line for an entire month, if they are needed at all in that time period. Thus, PREPA's marginal costs would not include the fuel costs of starting up its steam units or bringing them to their minimum stable load levels, or the costs of dispatching more-expensive resources when the steam plants cannot be started in a timely fashion. When the steam plants are the marginal units, the computer model would count only the incremental fuel costs of increasing output from an already hot boiler.

Finally, PREPA's estimates of the marginal costs for energy delivered to customers appear to be understated because PREPA uses a simple average of the hourly marginal

[64] See the spreadsheet entitled "WP 1 (Marginal Cost Worksheet) REV 2016-10-11.xlsx."

costs, rather than a weighted average of hourly prices, reflecting the correlation of as a function of load. In general, the highest-load hours will have higher marginal energy costs than lower-load hours; the load-weighted average kWh a customer consumes or saves will tend to be somewhat more expensive than the simple average.

2. Variable non-fuel costs

It is not clear whether PREPA's estimate of its marginal energy costs include variable O&M costs. If not, adding those costs would increase the marginal energy costs by several mills.

3. Renewable requirements

In the Final Resolution and Order for the Integrated Resource Plan (Case No. CEPR-AP-2015-0002), the Commission reported that "PREPA…says that the currently expected cost of new contracts in 2021 would be only $130/MWh" and suggests that new renewable projects can be procured for "approximate $100/MWh." Even the $100/MWh value would be $43/MWh higher than PREPA's $56.6/MWh estimate of avoided energy costs at generation.

Puerto Rico's current schedule for renewable requirements, as a percentage of sales, is as follows:

- 2015–2019: 12%
- 2020–2027: 15%
- 2028–2034: ramp up from 15% to 20%
- 2035: 20.0%

At the $100/MWh renewable cost above, the marginal cost of energy, including the need to supply renewable energy, would be at least ($43/MWh ×12%) = $5/MWh higher than PREPA's fossil-fuel energy estimate through 2019, $7/MWh higher in 2020–2027, and $9/MWh higher in 2035, plus applicable losses.

C. Generation Capacity

1. Timing of generation capacity need

PREPA has proposed to add hundreds of megawatts of capacity starting in 2020. As I discuss in Section IV.C.1, the IRP order allows PREPA to start planning for one to three small combined-cycle units at San Juan, to enter commercial operation starting as early as 2020, with the number and timing of the units required determined by load. Yet PREPA's marginal-cost study assumes that no load-related generation investments are avoidable until 2036, The marginal capacity cost should start in 2020, not in 2036.

2. Marginal generation capacity cost

In the original filing, Mr. Zarumba said that he had assumed that the marginal generation unit would be a Wartsila reciprocating engine (PREPA Exhibit 9.0, page 6), built at an installed cost of $1,124/kW in 2017$. That price would about 17% lower than the $1,356/kW in 2017$ assumed for that generation technology in the IRP (Table 2-3).[65] When this inconsistency was pointed out in discovery, PREPA indicated that the error would be corrected in the revised marginal-cost spreadsheet (CEPR-PC-09-02c). That revision was filed on October 14.

Mr. Zarumba claims that he "held discussions with PREPA Planning Department staff that the Wartsila reciprocating engine unit would be the appropriate technology in modeling the marginal generation capacity cost" (CEPR-PC-09-03) and that "only one technology was determined to be the lowest capital cost technology, the Wartsila model18V50Sgg" (CEPR-PC-09-06). While the Wartsila reciprocating engine is listed as a generation option in the IRP, PREPA did not include it in any portfolio in the IRP report. The units that PREPA is planning to add to its generation portfolio are actually much more expensive than the Wartsila engine. The IRP estimates a cost of $1,648/kW for the duct-fired Siemens SCC-800 combined-cycle units, which would be representative of the small combined-cycle units that the IRP Order approved for planning and/or acquisition at San Juan. That would be about 50% more expensive than assumed in the PREPA filing.

Mr. Zarumba claims that the hypothetical reciprocating engine "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." (Exhibit 9.0, page 6). He is correct that "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." (Ibid.) So he might have classified part of the cost of the avoidable combined-cycle unit—perhaps the $1,356/kW cost of the peaker—as demand-related, and the remainder of the cost as energy-related.

The original marginal-cost workpaper also annualized the capital cost at a real-levelized carrying charge, starting at 7.87% in the first year of operation and rising 2.5% annually and reaching an annual charge of 16% after 30 years. The marginal-cost workpaper describes the 7.87% value as the nominally-levelized carrying charge, but a nominally-levelized carrying charge does not rise with inflation. The workpaper reversed its terminology, referring to the real rate as nominal and vice versa. Also, Mr. Zarumba said

[65] To confuse matters further, the marginal-cost workpaper that PREPA filed with testimony and exhibits shows the capacity cost as being derived from a simple-cycle combustion turbine at $1,210/kW, rather than the reciprocating engine.

that his computations were based on a 20-year life of the reciprocating engine (Exhibit 9.0, p. 6), even though the computation was conducted over a 30-year life.

Mr. Zarumba's revised marginal-cost workpaper raises the carrying charge to 11.81%, by switching to the nominal carrying charge and increasing the fixed O&M for the unit from $1.83/kW-year to $23.43/kW-year. However, the computation still uses the 30-year life.

The marginal cost of generation capacity, and the assignment of that cost between demand and energy, should be revisited in the rate-design proceeding.

3. Allocation of cost to time periods

The marginal cost study allocates demand-related costs in a manner inconsistent with the factors (discussed in Section I.E.1.b) that determine how much generation capacity PREPA requires.

> 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. (Exhibit 9.0, page 20)

In effect, the marginal cost study has assumed that every hour contributes equally to the risk that load will exceed available capacity. Since that risk is spread over fewer MWh in the off-peak hours, PREPA has assumed that the reliability risk per MWh is higher in off-peak than in the on-peak period. I have never seen any analysis for any utility that would suggest that a kWh off-peak contributes more to reliability risk than a kWh on-peak.[66] It is also inconsistent with the assumption in Exhibit 8.0 that each class's contribution to demand-related generation costs results from one peak hour.

A more rational approach would allocate the reliability-related costs to the high-load hours in each month. The allocation of marginal capacity costs among time periods should be revisited in the rate-design proceeding.

D. Marginal Transmission Cost

The marginal cost study assumed that only "[i]nvestments that are required to ensure sufficient transmission capacity is available under normal and contingency conditions to reliably serve new load" (PREPA Exhibit 9.0, p. 11) PREPA confirmed that "[t]he

[66]The original marginal-cost analysis used periods of five high-season months and seven low-season months, with three peak hours per day; neither the high-season months nor the peak hours were identified. The revised analysis does not distinguish between seasons, and uses 13 peak hours on non-holiday weekdays.

transmission projects were classified assuming that [the] category [of load-related transmission] is limited to new load. This is why there are no transmission investments classified under this category." (CEPR-PC-09-25)

In other words, PREPA concluded that transmission investments could only be marginal, or avoidable by load reductions, or accelerated by load growth, if there were net load growth on the system. Since the PREPA forecast does not show any such growth, the marginal cost study assumed that no transmission investments were marginal over the next 20 years.

Yet PREPA is planning to add roughly $82 M of load-related transmission in the next three years alone. According to CEPR-PC-09-26, PREPA's capital plan for FY2017–FY2019 includes $48M in expansion projects, most of which represent new or expanded capacity, and $34M in improvement projects that included capacity increases.[67] PREPA categorizes many of these projects as being necessary to alleviate transmission constraints (which are almost always load-related) and/or improve reliability (which is usually load-related), although some are replacing existing equipment, which might require replacement regardless of the load (in which case only part of the cost may be avoidable).

If Mr. Zarumba had identified any marginal transmission costs, he would have allocated them evenly to every hour, as he did generation and distribution costs. Transmission costs should be allocated to the hours contributing to transmission stress, including the highest-load hours on each line during the year, as well as the prior high-load hours that contribute to overheating, premature aging of equipment, equipment derating, and the need for additional capacity.

E. Marginal Distribution Cost

As with transmission, Navigant and PREPA applied a very strict standard for including distribution projects in the marginal costs. Mr. Zarumba explains that the marginal distribution costs are limited to the "fraction of those investments [that] are associated with serving new load as opposed to replacement of existing infrastructure or to maintain or improve system reliability." (PREPA Exhibit 9.0, page 14)

Using this definition, PREPA identifies only $45M in load-related distribution projects for 2015 through 2015. (WP 1 (Marginal Cost) REV 2016-10-11, tab Calc-4) The marginal-cost study included only half of this value, on the grounds that some customers would be charged directly for half the costs "in the form of contributions in aid of construction" (Exhibit 9.0, p. 18). Navigant did not include any costs for load-related

[67] I excluded some projects that were reliability-related, including STATCOMs and some sectionalizers. I do not know whether those projects are avoidable by reduced load.

investments in line transformers, even though the cost-of-service study properly identifies line transformers as being entirely load-related. Navigant also assumed that additional distribution plant would not increase O&M.

Sorting out which projects are load-related is more difficult for distribution than for transmission. PREPA's descriptions of feeder projects often describe them simply as "improvements" of feeders, without specifying whether the improvements consist of repairs or expansions. PREPA was not able to provide much detail on the justifications of projects, as explained in more detail in the report of Commission experts Fisher and Horowitz.

Navigant's basis for excluding half of the marginal costs, on the grounds that customers contributing to load growth would be charged for a share of the projects, is inappropriate for a marginal-cost study. Avoiding the cost of a capacity increase is a benefit to Puerto Ricans, whether that benefit flows through PREPA's rates or directly to specific customers.

Review and improvement of the estimates of marginal distribution costs (and for that matter, the rest of the marginal-cost study) will require detailed analysis of investments project by project, and should be included in the rate-design proceeding.

As with generation, Navigant assumed that each hour contributes equally to demand-related distribution costs, so that an off-peak kWh has a higher marginal distribution cost that an on-peak kWh. The marginal distribution costs should be allocated across months and hours in proportion to the capacity of the substations peaking in each period.[68]

F. Marginal Losses

As explained in Section I.D.4, the marginal line losses associated with a marginal change in load are greater than the average line losses (total losses divided by total load), for a given load level.

Navigant and PREPA were unable to provide any data or analysis supporting their estimates of marginal line losses. In CEPR-PC-09-14, Mr. Zarumba promised that, in "the revised Marginal Cost worksheet[,] all sources are cited for the loss factors." The revised worksheet does not provide sources for the loss factors.

Mr. Zarumba also assumed the marginal losses at peak would be about half of the energy losses, even though marginal losses typically increase with load. Indeed, Navigant used the same loss factors for average and marginal losses, even though "Mr. Zarumba would

[68] As PREPA's data and analysis improves, the distribution costs could be allocated in proportion to the timing of peaks of substations with limited reserve, or peaks driving new substations and feeders.

expect marginal losses to be marginally higher than average losses. However, marginal losses were unavailable when the marginal cost study was prepared so average loss factors were used." (CEPR-PC-09-16)

It may take some years for PREPA to fully understand and model line losses on its system, but some progress towards consistency should be possible in the rate-design proceeding.

V. Subsidies and CILT

Historically, PREPA collected a 12.36% markup on fuel and purchased power, nominally intended to recover from customers the cost of contributions in lieu of taxes (CILT) it makes to the municipalities, as well as the cost of what PREPA calls "subsidies." The level of CILT and subsidies varies independently from the fuel and purchased-power costs, so this has not been an appropriate mechanism for recovering CILT and subsidies.[69]

Act 4-2016 requires that PREPA "shall propose separately the charges and adjustments corresponding to the costs of subsidies and the contribution in lieu of taxes" (§9), that the "bill shall itemize the categories of the different charges and credits to customers, including…the contribution in lieu of taxes, and subsidies created under in laws…" (§11).

Elsewhere, Act 4-2016 requires that "the Authority shall compute annually the cost of subsidies, grants, and contributions granted under laws in effect, rural electrification programs, public irrigation systems, public lighting system, and the contribution in lieu of taxes (CILT), and shall establish as a separate charge in its transparent bill the cost of the CILT and all other aforementioned subsidies as follows: (a) Payment equal to municipal taxes, CILT; (b) Cost of subsidies, contributions, public lighting, rural electrification programs, and public irrigation system." (§15).[70]

This change in the law, the unsuitability of the current mechanism and the setting of new base rates require a rethinking of the amounts that need to be added to revenue requirements to cover CILT and subsidies, as well as the amounts that should itemized in those categories on the bill.

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[69] PREPA's base rates have not changed since 1989, so its revenues have been only loosely related to its requirements; the mismatch between the markup and the CILT and subsidy burden is only part of the problem.

[70] Act No. 22-2016 defines subsidies to mean "any subsidy, aid, credit, tax credit, or grant created by law or regulations whose effect or purpose is to reduce the cost of the electric power or water bill of a customer." The context is different in Act 22 than in Act 4.

A. PREPA's Proposed "Subsidy Charge"

The PREPA filing proposed an addition to the revenue requirements, and a reconciling adjustment charge, to recover contributions in lieu of taxes (CILT) to the municipalities, which is structured as an allowance of free electricity provided to each municipality (the cost of which is then allocated to other customers).[71] In addition, PREPA proposed a similar addition to the revenue requirements and a single reconciling adjustment charge to recover what it deemed to be intentional subsidies (as opposed to "cross-subsidies" created when a tariff collects less revenue than the COSS suggests it should), including the following 19 components:[72]

- free electricity and other services provided to municipalities for public lighting and related functions, which were split off from the CILT category in 2016);[73]
- PREPA's assessment to pay the costs of operating the Energy Commission;[74]
- PREPA's financial loss on its continuing irrigation-district operations;
- the differences between revenues under four existing distinct tariffs (RFR, RH3, LRS, and GAS) and the revenues that would have been collected from those customers under standard tariffs otherwise applicable to those types of customers (GRS and GSS);
- three existing targeted provisions that bill some non-residential customers (churches and social welfare organizations, condominium common areas, and rural aqueducts) at the GRS rate, rather than the GSS, GSP and GST rates;
- two existing discounts for fixed amounts of dollars (industrial tax credits) or energy (life-preserving equipment);
- four existing discounts that vary with consumption (the residential fuel-oil credit,[75] direct debit, hotel discount, and downtown small-business discount) from otherwise-applicable rates based on need and other considerations;

[71] Municipalities that use less than their allowance are eligible for a rebate.

[72] PREPA describes most of these items in different ways in different places.

[73] Public lighting services will be provided without charge and the costs will be collected in the subsidy charge, while the remainder of municipal electric consumption will subject to an energy cap for each municipality and the costs will be collected in the CILT charge.

[74] In some places (e.g., Schedule G-1 and CEPR-RS-03-07), PREPA lists the CEPR assessment separately from the subsidies.

[75] Schedules L-2 and E-8 refer to the residential fuel credit as being given to "LICS customers," which those Schedules use to refer to the LRS and RH3 tariff, but the customers on GRS tariff

- an as-yet-unquantified imputed overpayment to net metering customers, to be set as the difference between the retail energy rate and PREPA's estimate of long-term marginal costs;[76]
- two potential future items (the difference between revenues from the customers on the economic-development and load-retention riders and what they would have paid if operated in the same manner under the applicable standard industrial rate).

All of these items are listed and quantified in Schedule L-2 (which is the same as Schedule E-8),[77] except for the net metering, economic-development and load-retention items. PREPA stated in CEPR-PC-05-01 that the subsidy charge would be limited to the items listed in Schedule L-2 SUPP. Yet PREPA declared that the subsidy charge would include the net-metering item in Exhibit 4.0, p. 34, and the other two items in a telephone conference on October 31.

Table 8 lists these nineteen items, with PREPA's estimate of the cost in FY 2017.[78]

code 111 (students, the elderly and the handicapped using less than 425 kWh in the month) receive more than half of this credit.

[76] Zarumba and Granovsky say their purpose is "to explicitly recognize that the premium paid over avoided cost is triggering cost shifting to other customer groups which is increasing their average price" (Ex. 4.0, pp. 34–35). Even in the rebuttal testimony, Messrs. Zarumba and Granovsky declined to estimate the magnitude of the alleged net-metering subsidy, or even the process by which that subsidy would be computed and corrected for errors in PREPA's marginal-cost projections.

[77] PREPA provided the derivation of these items in CEPR-PC-01-026, Attachment 1, other than the Irrigation District deficit.

[78] I broke out PREPA's estimates for the two "low-income" classes (one of which is not necessarily low income) using the data in CEPR-PC-01-026. I have not been able to completely follow PREPA's estimation process.

Table 8: PREPA Claimed FY 2017 Cost of Subsidies, CILT and Public Lighting

Subsidies/Credits	PREPA 2017 Estimate	
Life-Preserving Equipment	$2,547,894	
General Agricultural Service Tariff	524,933	
Analog Rate (Churches, Public Well-being) on GRS	5,521,495	
Low-Income Consumer Subsidies	16,438,851	
LRS Tariff		$15,416,766
RH3 Tariff		$1,022,085
Hotel 11% Discount	5,463,401	
Rural Aqueducts on GRS	4,220	
Irrigation District Deficit	4,152,000	
Residential Fuel Subsidy	18,630,971	
Condominium Common Areas on GRS	1,321,289	
Direct Debit Credit	129,428	
Downtown 10% Commerce Subsidy	1,775	
Fixed Public Housing Rate (RFR Tariff)	20,076,641	
Act 73 Income Tax Credit	258,121	
Total Subsidies/Credits	**75,071,019**	
Other Subsidy Categories		
Public Lighting	93,241,901	
Energy Commission Assessment	5,800,000	
Total Proposed Subsidy Charge	174,112,921	
Unquantified Claimed Subsidies		
Net Metering	unknown	
Economic-Development Rider	tbd	
Load-Retention Rider	tbd	
Contribution in Lieu of Taxes	51,783,821	
Grand Total	**$225,896,742**	

Source: Schedules L-2 and E-8; CEPR-PC-01-026 Attachment 1.

PREPA's filing treated each these items both as requiring an increase in revenue requirements (e.g., in Schedule A-1, Schedule G-1, and CEPR-RS-03-07) and as a subsidy that should be recovered through the subsidy charge. PREPA presents the information in different ways in different documents. For example, Schedule A-1 includes $37.7 million in "CILT Subsidy Recovery Required in Base Rate," $5.8 million for "Energy Administration Assessment" and "Fuel Pass-through" of $182.4 million, for a total of $225.9 million.

PREPA asserts, based on the cost-of-service study, that various tariffs are "cross-subsidized" by other customers because the rates are not set high enough, even in PREPA's proposed revenue allocation. PREPA does not include these unintentional cross-subsidies (mostly the result of historical ratesetting) as subsidies for the purpose of computing additions to revenue requirements or computing the subsidy charge. I agree with this distinction. As explained in Section III, the cost-of-service study is not sufficiently reliable for quantifying these cross-subsidies.

B. Errors in the PREPA Proposal

Most of the items that PREPA claims as subsidies should be not be added to revenue requirements, or should be excluded from the subsidy charge.

1. Subsidies as part of the revenue requirement

Of the items PREPA lists as subsidies, only the Energy Commission Assessment ($5.8 million) and the Irrigation District shortfall ($4 million) are potential additions to the costs that PREPA must collect through rates.[79]

PREPA's projected revenues reflect the requested rates for the GAS (including the rural aqueducts), LRS, RH3 and RFR tariffs, so PREPA has double-counted about $37 million in revenue requirements, which should be removed from the PREPA's revenue request.[80] In their rebuttal testimony, Messrs. Zarumba and Granovsky acknowledged "inconsistencies with previous proposals" regarding these discounted rates:

> General Agriculture Service, LICS, and the Fixed Public Housing Rate subsidies were not explicit subsidies in that no credit was being provided to customers. This was acceptable given PREPA's historical approach of estimating subsidies with an 11% adjustment to fuel and purchased power costs, but was an error in our approach of explicitly accounting for all subsidies. The total error was $37M based on "Schedule E-8 REV", and the proposed rate design now includes these subsidies explicitly." (PREPA Exhibit 24.0, page 15)

This explanation is not very clear, but Messrs. Zarumba and Granovsky appear to be saying that PREPA has removed the double-counting of revenue requirements. The rebuttal of Messrs. Pampush, Porter and Stathos appears to confirm this. (PREPA Exhibit 23.0, p. 3)

Aside from the GAS, LRS, RH3 and RFR tariffs, the other discounts are also not additions to PREPA's revenue requirements. Rather, the other discounts reduce the amount that PREPA would bill to customers and the revenues it would record. In computing revenues for 2017, at either current or proposed rates, PREPA does not subtract the discounts. Hence, PREPA's reports revenues by rate class that are higher

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[79] Commission Experts Smith and Dady examine whether the Irrigation District costs are truly incremental.

[80] The rebuttal testimony revises these estimates.

than it would actually expect to bill.[81] This treatment introduce unnecessary confusion into ratemaking.

The discounts (other than the GAS, LRS, RH3 and RFR tariffs) should be reflected as reductions in revenues relative to the revenues that would have been collected from the applicable tariffs, in the absence of the subsidy or CILT policy.

In Appendix PLC-2, I illustrate how the credits for Life-Preserving Equipment, Residential Fuel Subsidy, Direct Debit Credit, Condominium Common Areas, Downtown Commerce Subsidy, and the Hotel Discount can be reflected in the computation of revenues in Schedule H for tariffs GRS, RH3, LRS, GSS, GSP and GST.[82] In these computations, I simply modified the tabs for these tariffs from PREPA's October filing update by adding lines for the items that PREPA claimed as subsidies, disaggregated by tariff from CEPR-PC-01-026.

PREPA already reduces revenues by rate class by the expected credits for net metering. To the extent that behind-the-meter distributed generation reduces sales, PREPA should reduce its projection of revenues, rather than impute a value based on long-term marginal costs.

The Commission should instruct PREPA to reduce the revenue requirements adder for CILT and subsidies to the Irrigation District shortfall; eliminate the double-counting of the GAS, LRS, RH3 and RFR tariffs; and reflect the other items as reductions to revenues.

If and when the Commission approves agreements with customers under the Economic-Development and Load-Retention Riders, those should not be treated as subsidies.

2. Identifying actual subsidies

PREPA places a number of inappropriate items into the "subsidy" category.

Four of the items claimed by PREPA are clearly not subsidies in the normal sense of that word:

[81] PREPA also expects to collect less than it bills; the difference is shown as bad-debt expense.

[82] I do not have a breakdown of CILT, the complementary streetlighting, or industrial tax credit by tariff. PREPA does not provide a revenue computation for streetlighting, in any case. PREPA should reflect all the discounts and credits by tariff, and provide a proof-of-revenue computations for the streetlighting and unmetered tariffs.

- The Energy Commission Assessment ("CEPR") is not a subsidy, but an operating cost.[83]
- The Direct-Debit billing discount is not a subsidy. Either direct debit reduces PREPA's costs, and is cost-justified, or it should be reduced or eliminated. I return to this issue in Section VII.D.1.e.[84]
- The reductions in rates anticipated for the Economic-Development and Load-Retention Riders are not subsidies. The purpose of these riders is to increase PREPA revenue, by attracting or retaining customers. If PREPA actually needs higher rates due to the riders, it will have done something wrong.

Seven other items are probably not subsidies, either because they are designed to increase revenue or they are reasonably priced at the at the current rate.

- The downtown business discount, the Act 73 income-tax credit, and the hotel discount appear to be designed to increase sales.
    - Act 73-2008 clearly indicates that the purpose of the tax credits and other measures in that law were intended to increase industrial development and employment, which would usually also increase electricity revenues.
    - Act 22-2016 notes that "although the energy subsidy granted to the hotel sector has helped it bear high energy costs, such sector has increased its energy consumption after being granted the subsidy" and "With the purpose of revitalizing the tourist industry as a source of jobs and income for our people, the Electric Power Authority is hereby authorized to grant a credit on the monthly power consumption bill to every hotel, condo-hotel or *parador* duly qualified by the Puerto Rico Tourism Company."
- Act 169-2009 established the downtown commercial discount enable existing businesses to remain in business and to "foster [the] maximum development" of urban centers, which would result in PREPA retaining and increasing sales.
- It is difficult to determine whether the GAS tariff, rural aqueducts, condo common areas, and analog rate are subsidies, or just more appropriate rates for the specific types of customers.[85]

[83] PREPA justifies including the Energy Commission assessment in the subsidy charge by citing Act 4-2016 states that "The Authority shall obtain the necessary funds to pay the Commission from the revenues arising from the subsidies item on its rate."

[84] Navigant has belatedly agreed to recategorize the direct debit as an operational expense rather than a subsidy (CEPR-AP-2015-0001, Oct 31, 2016 Conference Call, Request No. 1, Response to the Production of Documents and Information).

- The GAS tariff that PREPA set is lower than the GSS rate for most customers, but the GAS customers may be less expensive to serve, depending on actual load shapes of these customers and the relative cost of maintaining the distribution system in rural versus urban areas. The data in CEPR-PC-02-020 show the loads of the GAS customers to be lower than those of commercial customers on the GSS tariff (tariff code 211) for the highest-load hours and higher in the low-load, low-cost early-morning hours. PREPA has not proposed to reduce the differential between the GAS tariff and the GSS tariff.
- PREPA does not maintain separate tariff codes or estimate load shapes for the rural aqueducts, condo common areas, and analog rates, so I cannot make the same comparison for these rates. The following represent my thoughts about the likely characteristics of these customers, all of which suggest that the GRS rate may be an appropriate reference for these users.
  - The aqueducts may tend to have very flat load shapes, with relatively little on-peak energy. PREPA does not have the data necessary to determine whether the aqueducts are subsidized.
  - The condo common areas are likely to have load shapes similar to GRS customers, and perhaps even better, if they maintain interior and exterior security lighting all night.
  - While churches probably have a wide variety of load shapes, many certainly have a disproportionate share of their load on Sunday, early mornings, and perhaps early evening, before PREPA's peak hours.
- Until PREPA corrects its marginal-cost study and the Commission completes a review of net-metering, it would be premature to determine what (if any) portion of the net-metering credit can be considered a subsidy of the net-metering customers, As I discuss in Section IV, the marginal-cost study requires further work, especially with respect to the value of renewable energy.

Limiting the subsidies to discounts that customers receive compared to the rate that they would normally be served under, solely for the benefit of the customer and without expectation of lower costs or increased sales, the only items that can clearly be identified as subsidies are:

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[85] In the past, PREPA has charged the Puerto Rico Aqueduct and Sewer Authority (PRASA or AAA) a statutory fixed rate. Through FY2016, that rate was 22¢/kWh, and which may not have represented a subsidy in recent years. In FY2017, the preferential rate would have fallen to 16¢/kWh, a price which is very likely to be subsidized, and PREPA suspended it. I discuss the PRASA rate in Section VII.D.2.f.

- Life-Preserving Equipment
- LRS Tariff
- RH3 Tariff
- RFR Tariff
- Residential Fuel Subsidy
- Public Lighting

The Irrigation District deficit and the Energy Commission assessment are more appropriately treated as operating costs. The remaining items should be excluded from the subsidy charge.

3. Subsidies allowed in the subsidy charge

Most of the items in PREPA's list of subsidies are required by specific acts of the Legislature, which I take to be the "special laws" referred to in Act 04-2016, or other entries in the list of criteria for inclusion in the subsidy charge: "the cost of subsidies, grants, and contributions granted under laws in effect, rural electrification programs, public irrigation systems, public lighting system."[86] PREPA identifies these laws in Schedule L-2 SUPP for the items included in Schedule L-2. Act 83-1941 requires PREPA to provide the fuel-oil subsidy for "eligible" customers, but does not specify which groups will be included in that definition. Since Act 4-2016 requires that PREPA promote renewables, it is arguable that any actual subsidy of net-metering would be considered to be granted by law.

The special rate for general agriculture would seem to be covered by the "rural electrification" category, and the inclusion of the irrigation-district deficit and the rural aqueducts by the "public irrigation" category.

Messrs. Zarumba and Granovsky assert, with respect to the entire $168.3 million in claimed subsidies (they excluded the Energy Commission assessment from this total, without explanation), that "PREPA is required to provide these subsidies. It is our understanding that these subsides are legislatively mandated." (PREPA Exhibit 4.0 at 11).

Nonetheless, I have not found any legislative language that would mandate inclusion any of the following in the subsidy charge:

- the RH3 discount,
- the imputed costs from the economic-development or load-retention riders, or

[86] I am not offering a legal opinion in this regard.

- the direct-deposit discount.

4. Summary of subsidy characteristics

Table 9 summarizes the discussion in the previous sections.

Table 9: Summary of Characteristics of PREPA-Claimed Subsidies

Subsidies/Credits	PREPA 2017 Estimate	Contribution to Revenue Requirement	Is it a Subsidy?	Required by Law?	Allowed in Charge?
Life-Preserving Equipment	$2,547,894	revenue reduction	Yes	Y	Y
General Agricultural Service	524,933	double-counted	Cost ?	N	Y
Analog Rate	5,521,495	revenue reduction	Cost ?	Y	Y
Low-Income Tariffs					
LRS Tariff	$15,416,766	double-counted	Yes	Y	Y
RH3 Tariff	$1,022,085	double-counted	Yes	N	N
Hotel 11% Discount	5,463,401	revenue reduction	Growth	Y	Y
Rural Aqueducts on GRS	4,220	double-counted	Cost ?	N	Y
Irrigation District Deficit	4,152,000	**Incremental**	No	Y	Y
Residential Fuel Subsidy	18,630,971	revenue reduction	Yes	Y	Y
Condo Common Areas	1,321,289	revenue reduction	Cost ?	Y	Y
Direct Debit Credit	129,428	revenue reduction	No	N	N
Downtown 10% Subsidy	1,775	revenue reduction	Growth	Y	Y
RFR Tariff	20,076,641	double-counted	Yes	Y	Y
Act 73 Income Tax Credit	258,121	revenue reduction	Growth	Y	Y
Other Subsidy Categories					
Public Lighting	93,241,901	revenue reduction	Yes	Y	Y
Energy Commission	5,800,000	**Incremental**	No (?)	Y	Y (?)
Total Proposed Subsidy Charge	174,112,921				
Unquantified Claimed Subsidies					
Net Metering	unknown	revenue reduction	Cost ?	Y	Y
Economic-Development Rider	tbd	revenue reduction	Growth	N	N
Load-Retention Rider	tbd	revenue reduction	Growth	N	N
Contribution in Lieu of Taxes	51,783,821	revenue reduction			

Notes:

Cost ? means that there may be no cost.
Growth means that the discount would tend to increase sales and hence revenues.
No (?) flags the possibility that Act 4-2016 requires inclusion of the Energy Commission Assessment

C. Treatment of CILT and Subsidies in the COSS

The purpose of the cost-of-service study is to indicate whether each class is being assigned the share of revenues that would be consistent with the Commission's technical and policy directions. In order to be useful in that determination, the cost-of-service study should assign to each class the costs that the Legislature and PREPA (and in the future, the Commission) have determined the class should bear.

The PREPA cost-of-service study does not reflect these directions. For example, the RFR, LRS and RH3 tariffs are explicitly subsidized rates, with the expectation that significant portions of their costs will be borne by other customers. Yet the cost-of-service study does not reflect that expectation. Even if revenues on those tariffs added up to all the costs that the Legislature and Commission intend they pay, the cost-of-service study would still show those tariffs to be paying less than their share. That problem is rolled into the cost-of-service results for the residential class.

Similar issues arise with the GAS rate, which PREPA considers to be subsidized. If each tariff's revenues in the cost-of-service study are corrected to reflect various discounts, the same problem would occur in the GRS, GSS, GSP, GST and perhaps other classes.

This distortion in the cost-of-service study can be corrected easily, by including the subsidy to each tariff in the "other revenue" line or adding a "transfers" line (e.g., in the Schedule G-1 Calc-4 and Calc-5 series of tabs), reducing the bottom-line revenue requirement. Table 10 provide an example of this approach, for the residential tariffs. Each tariff is allocated a "contribution" responsibility towards CILT and subsidies, but each class also receives a transfer credit from the subsidy fund. For GRS, the contribution allocation is much larger than the subsidy transfer; for the three other tariffs, the subsidy exceeds the contribution allocation.

Table 10: Reflecting Subsidies as Transfers in the Cost-of-Service Study

Classification:	RH3	RFR	LRS	GRS
Production Energy	$1,451,156	$16,940,982	$39,147,501	$366,474,489
Production Demand	$1,380,651	$17,025,087	$33,964,830	$324,229,988
Transmission Demand	$372,358	$4,591,623	$9,160,229	$87,444,006
Distribution Demand - Primary	$485,475	$5,986,484	$11,942,960	$114,008,101
Distribution Demand - Secondary	$589,481	$7,269,006	$14,501,574	$138,432,757
Customer	$1,084,005	$6,542,688	$27,363,644	$179,383,811
Public Lighting Assignment				
Contributions	$269,467	$3,145,796	$7,269,358	$68,051,194
Other Income	-$50,042	-$584,202	-$1,349,984	-$12,637,708
Transfers	**-$1,406,384**	**-$20,076,641**	**-$24,942,245**	**-$11,398,515**
Direct Assignment	$10,634,579	$25,731,367	$2,984,692	$17,437,359
Total Revenue Requirement	$14,810,745	$66,572,188	$120,042,559	$1,271,425,484
PREPA-reported Requirement	$16,217,129	$86,648,830	$144,984,804	$1,282,823,999

D. Exemptions from the Subsidy Charge

PREPA does not propose to charge the RFR, RH3 or LRS tariffs for the subsidy charge, or to charge the RFR rate for the CILT charge, even on usage over the customer's fixed-price block.[87] Since the CILT and subsidies are currently collected through the fuel and purchased-power riders, which are paid by these customers, these are additional discounts for these customers, beyond the differences between their tariffs and the GRS tariff. PREPA does not propose similar exemptions for other subsidized customers, including the GAS tariff and the GRS 111 tariff code fuel subsidy for students, the elderly and the handicapped.

I have not evaluated the adequacy of the overall discounts for the these tariff codes, and I have no opinion regarding their overall rate level. The CILT and subsidy exemptions should be reviewed in the rate-design proceeding.

In terms of the rate design, it would be easier to understand the level of the discounts if the CILT and subsidy were charged to the RH3, LRS and (above the fixed blocks) RFR tariffs and the base rates were reduced by about the same amount (assuming that the Commission wants leave the total subsidies at the proposed level). For example, it would be much easier to understand and explain the discount for LRS as "three cents off the general residential rate up for consumption up to 425 kWh/month, and one cent off the general residential rate for consumption above 425 kWh," rather than "two cents off the general residential rate up to 425 kWh/month, and an exemption from the subsidy charge for all energy." Rethinking the structure of the LRS and RH3 tariffs, and the GRS 111 discount, should be on the issues list for the rate-design proceeding.

VI. Structuring Riders

A. FCA and PPCA Cost Recovery

Currently, PREPA recovers all of its fuel costs and purchased-power costs through separate, but very similar, Fuel Cost Adjustment (FCA) and Purchased-Power Cost Adjustment (PPCA) cost riders that it sets and reconciles on a monthly basis, including reconciliation of over- or under-recoveries in previous months. In contrast, the costs of debt service; distribution, transmission, non-fuel generation expenses; and most other costs are recovered through the base rates, which have not been modified since 1989. The

[87] The latest proposed tariff (Schedule J-1 REV 2016-10-11) does not list the subsidy charge as being applicable to the LP-13, the subsidy charge is listed in the LP-23 revenue calculation in Schedule H. I assume that this discrepancy is another clerical error on PREPA's part.

existing FCA and PPCA are increased by 12.36% to cover the costs of Contribution in Lieu of Taxes (CILT) and subsidies.[88] (CEPR-PC-01-08)

The fuel and purchased-power rates have dominated most customers' bills. For example, for the main residential rate (GRS) in 2014, base rates accounted for about 20% of revenues, fuel over 50%, purchased-power about 20%, and the surcharge for CILT and subsidies less than 10%.

PREPA proposes to modify three aspects of the cost-recovery mechanisms:

- The recovery of CILT and subsidies would be moved from the FCA and PPCA to separate riders.
- The projected costs for fuel and purchased power would be transferred to the new base rates.
- Differences between actual fuel and purchased-power costs and the allowance for those costs in base rate would be recovered through new fuel and purchased-power riders reconciled quarterly, or more frequently in response to large changes in projected costs (Schedule J-1 REV, pp. 49–52).[89]

PREPA provided examples of the computations that would be used to set the FCA in CEPR-PC-01-015 Attachment 1.

In any one month, all billed classes would be charged the same FCA and PPCA per kWh.[90]

1. Base rates or riders

PREPA proposes to include the forecast level of fuel and purchased-power expense in base rates, and recovering the deviation from those forecasts through the FCA and PPCA. This approach is revenue-neutral and has no inherent adverse effects on cost allocation or rate design. Some rate-design options, such as inclining-block rates and time-of-use rates, may be easier to structure with the fuel and purchased-power costs folded into base rates. For example, it is difficult to implement a time-of-use tariff with an off-peak rate

[88] CILT and subsidies are discussed in detail in Section V.

[89] The filed purchased-power rider tariff (and the October update) contained several references to fuel costs. In the version of Schedule J provided with the rebuttal, PREPA corrected most of those errors, but still includes a reference to PREPA supplying "all detail on the type of fuel forecasted to be consumed," and must be rewritten.

[90] While PREPA proposes to allocate the fixed charges from the two large fossil IPPs (AES and EcoElectrica) to classes on the basis of estimated class contribution in proportion to tariff-code NCP, which would result in different purchased-power charges by class, PREPA proposes to recover the PPCA as a uniform rate per kWh of sales.

discount of 5¢/kWh, if the base energy rate is only 4¢/kWh to begin with. I have seen rate designs with negative off-peak energy base rates, but those are probably somewhat confusing to customers. If including the projected fuel and purchased-power expense in base rates raises the average base rate to 14¢/kWh, having an off-peak rate of 9¢/kWh looks quite reasonable. Customers may also find it easier to think about their energy choices and cost reductions, looking at rates of:

- 9¢/kWh off-peak and 20¢/kWh on-peak (plus 1.5¢/kWh in CILT and subsidy adders), rather than
- –1¢/kWh off-peak and 10¢/kWh on-peak (plus 10¢/kWh in FCA and PPCA and 1.5¢/kWh in CILT and subsidy adders).

Including a base level of CILT and subsidies into base rates might also make it easier for customers to understand the cost of energy usage. But these adders would be much smaller than the FCA and PPCA, so leaving them outside base rates would not be as confusing for consumers.[91]

On the other hand, I read Act 4-2016 as requiring that all fuel costs occur on one charge on the bill and all purchased-power costs appear on another. That would be easier if all fuel charges were in the FCA and all purchased-power costs in the PPCA.

Efficient rates can be designed with either:

- most fuel and purchased-power costs in base rates, with lines on the bill summing base fuel + FCA and base purchased power + PPCA, or
- all the fuel and purchased-power costs in riders, with a line on the bill showing total energy charges (the sum of base rates, FCA, PPCA, CILT, subsidies, transition charge).

With some effort, the transparent bill (supplemented by PREPA’s web site) should be able to provide adequate information under either structure.

For the design of the formal tariffs, I recommend that the base rates exclude purchased-power and fuel costs, all of which would be included in the PPCA and FCA computations. The bill can present the rates both in that format and with total energy rates per kWh.

[91] Keeping the CILT and subsidy charges in separate adders will give the Commission greater flexibility to exclude some part of the subsidy charge from the net-metering credit and/or charges to some tariff codes.

2. Allocation of purchased power costs

As discussed in Section II.F.1.b, PREPA proposes to reallocate from energy to peak load the portion of the purchased-power charges that does not vary with the amount of energy provided by AES and EcoElectrica. As explained above, a large portion of those fixed costs were incurred to provide access to low fuel costs, and therefore should be treated as energy costs. In the cost-allocation proceeding, the Commission should consider what portion of the purchased-power costs should be allocated based on energy usage.

3. Frequency of reconciliation

PREPA is proposing to transition from monthly reconciliation and resetting of the fuel and purchased-power riders to a quarterly review schedule. In the event that projected costs for the quarter change by more than 10%.during the quarter, PREPA would trigger an accelerated adjustment on a monthly basis.[92]

The proposed reconciliation schedule is not very different from the monthly reconciliations. There is little down-side to allowing PREPA to avoid some small monthly adjustments. The trigger for adjustments should be changed, so that the same dollar deviation (rather than the same percentage deviation) triggers recomputation for each rider. Based on the forecasts of fuel and purchased-power in the filing, a 10% change in quarterly fuel costs would be $16 million.[93] That same amount would be an 8% change in purchased-power costs. The Commission should clarify in the hearing the dollar amount of variation in these riders that PREPA can tolerate and set the triggers for accelerated reconciliation appropriately.

Either the existing or proposed adjustment schedules would be reasonable. Subject to an information that may be elicited in the hearing, I recommend that the Commission adopt PREPA's proposed schedules, with revised triggers for accelerated adjustments.

B. CILT and Subsidies Riders

PREPA has traditionally increased the FCA and PPCA by 12.36% to recover at least part of the CILT and other subsidies. The levels of these expenses and discounts do not vary with fuel and purchased-power costs, so decoupling recovery from the FCA and PPCA is logical and efficient.

[92] The accelerated adjustment test requires a computation comparing original and updated forecasts. PREPA has not provided the detailed formulation of its proposed computation, and its tariff language is not identical to the description in CEPR-PC-01-23, which suggests that the trigger would reflect revenues from the adder, as well as the average rider costs. As explained in the next paragraph, I recommend that the Commission change the acceleration trigger to eliminate a percentage computation.

[93] With more realistic fuel prices, the trigger for accelerated adjustment would be even higher.

As explained in Section V.A, PREPA proposes separate riders for CILT and for other subsidies.

PREPA has proposed that customers in the LRS, RFR and RH3 tariffs be exempt from the subsidy charge, in addition to the RFR class being exempt from the CILT charge, and reflects those exemptions in its rate-design computations. These exemptions represent further subsidies, beyond the discounts embedded in the base rates for these tariffs and the fuel-oil credit to the LRS and RH3 tariffs. PREPA's approach to exemptions from the CILT and subsidy charges is inconsistent, since it does not apply the exemption to other tariff codes that it considers to be subsidized, such as GRS 111 and GAS, to customers on other discounted rates or to the classes with CILT load. Mr. Zarumba apparently recognized that these inconsistencies are problematic, when he said:

> The argument against collecting the subsidy from customers receiving that subsidy is that the "circular flow of the funds," that is, PREPA would be charging customers for a portion of the cost of a subsidy that it was giving back to the same customer. In other words, assessing a charge to defray the cost of a subsidy from the customers to whom it been determined the subsidy should go is self-defeating. (CEPR-PC-01-19)[94]

The circularity is even more pronounced where PREPA assumes the CILT and subsidy charges will be collected from customers who do not pay for their power: the CILT loads and the customers receiving no-charge energy under the life-preserving-equipment discount. The Commission should reconsider in the rate-design proceeding which discounted rates should be exempt from the CILT and/or subsidy charges, and how those charges should be reflected in rate design for tariffs in which some or all loads are discounted.

It does not appear that either the CILT or the discounts are volatile enough to require a separate rider, especially as long as PREPA is filing annual rate adjustments under a formula rate mechanism or the equivalent. In particular, CILT and the CEPR assessment can be included in rates like any other expense, and the discounts can be reflected in the computation of revenues from each tariff. Any variation in the discounts from the forecast values would be reflected in the revenue true-up mechanism.[95]

As I discuss in Section VIII.C.2, the CILT and subsidy charges should be assessed to net-metering customers on all energy taken from PREPA, but not on energy the customer generates for its own use.

[94] Mr. Zarumba's exact intent in this response is difficult to discern.

[95] If the CILT charge remains in a separate rider, the cost-adjustment tariff should be corrected to remove the reference to including "all detail on the type of fuel forecasted to be consumed" that PREPA added to the version of Schedule J dated November 16.

C. Energy-efficiency Rider

PREPA does not yet have an energy-efficiency program, but when it does, it will require a mechanism for recovering energy-efficiency costs without delaying program deployment for a rate-setting proceeding. As required by the Commission's Filing Requirements, PREPA has proposed an energy-efficiency rider. PREPA's versions of this new rider in the original filing and the October update largely followed the design of the fuel and purchased-power riders, with quarterly adjustments and the opportunity for accelerated adjustments as needed. PREPA's approach is appropriate, with a few corrections.

First, the filed tariff language includes confusing and unnecessary references to fuel, due to PREPA's having copied the rider language for the fuel-cost rider. Mr. Zarumba promised a corrected version of this rider (and the purchased-power rider), but it has not been provided.

Second, as I discuss in Section VI.A.3, the trigger for accelerated adjustment should be converted to a consistent dollar value across all three riders (fuel, purchased-power and energy-efficiency) to which it would apply.

Third, as I discuss in Section VIII.C.2, PREPA proposes to charge each net-metering customers for the energy-efficiency rider for all the energy the customer receives from its own generation, as well as the net energy it takes from PREPA. As discussed below, I recommend that those customers be charged for all the energy they take from PREPA, and receive no energy-efficiency rider credit for the energy they provide to PREPA, but not be charged for the energy provided by their own generation.

On November 21, PREPA provided an update to the energy-efficiency cost adder, which eliminates the inappropriate references to fuel costs, eliminates the accelerated adjustment, and changes the adjustment schedule from quarterly to annual. Annual setting of cost recovery for energy-efficiency may constrain PREPA's ability to pursue energy-efficiency programs on a timely basis. The Commission should investigate PREPA's motivation for proposing these changes in timing of the energy-efficiency cost updates.[96]

[96] This update adds the following provision to the energy-efficiency tariff: "Recovery of Discounts: PREPA shall recover any discount approved by the Puerto Rico Energy Commission in the Subsidies Adjustment clause." This language was probably an accidental repeat of the same provision from the load-reduction and economic-development riders.

VII. Intra-class Rate Design Issues

A. Principles of Rate Design

The general objectives of rate design are to provide understandable, stable, and efficient price signals, while preserving reasonable fairness among customers within each tariff class.

B. Unbundling Rates

Navigant explains its unbundling proposal as follows:

> …customers have been provided other options for receiving all or a portion of their electric service. Therefore, unbundling of tariffs is necessary in order to properly price the subcomponents of electric service used by each customer and avoid cross-subsidization. (Ex. 4 at 28)

Unfortunately, Navigant simply disaggregates each bill component into generation, transmission and distribution. In order to be useful for dealing with wheeling and distributed generation, the unbundling would need to distinguish between costs that PREPA can avoid if the customer (for example) finds another power supplier and the costs that are unavoidable or strandable.[97] Because existing investment are usually sunk, the costs of those specific assets cannot be avoided; but PREPA may avoid similar future investments if the customer reduces its reliance on PREPA's system.

For generation, the avoidable portion would include the cost of the power plants that PREPA proposes to build, with spending in starting 2019, and the new Palo Seco units entering service in 2021, as well as the O&M and capital additions avoided through the mothballing or retiring of additional units. Wheeling and distributed-generation customers can bypass those costs by switching generation source. The strandable generation cost would be any surplus of the embedded cost over the value of avoided generation.

PREPA currently has no wheeling arrangements, and the treatment of distributed generation will be considered in an upcoming proceeding. There is no urgency in unbundling rates , which can be taken up in the rate-design and net-metering proceedings. The rates approved in this proceeding should be bundled, to reduce confusion, given the myriad other changes in PREPA's rates.

[97] I will try to use the term "avoidable" to refer to costs that the PREPA system can avoid, due to lower loads. I refer to the costs that a customer can avoid by reducing its load as "bypassable." I do not intend any pejorative connotations by that term.

C. Basic Components of Base Rates

While some rates have special rate structures—such as rate RFR's fixed prices for a fixed block of energy, determined by the number of rooms in the customer's apartment—most utility revenue is recovered through three types of rates: energy, demand and customer charges.

1. Energy charges

Energy charges are usage charges, imposed per kilowatt-hour of consumption. Energy charges encourage and reward energy efficiency and conservation.

Energy charges can be part of base rates that change only with rate proceedings, or in riders that change more frequently. Energy charges can be the same for the customer's entire consumption, or they can vary in several ways:

- By usage level within the month. For example, the LRS tariff currently charges a base rate of 1.46¢/kWh for the first 425 kWh per month and 4.97¢/kWh above that level.
- By month or season.
- By time of consumption within a month, by time of day, by type of day (weekdays versus weekends).
- In response to system conditions (e.g., rising during periods with high loads and/or major generation and transmission outages).

The first two energy-rate variations can be applied with conventional energy metering. The other variations require more sophisticated metering that records the load in each hour or communicates that load to the utility.[98]

2. Demand charges

a. The nature and use of demand charges

A demand charge applies a rate in $/kW to the customer's maximum load in the month. Various utilities measure that maximum over 15 minutes to an hour. PREPA uses the 15-minute average.

Demand charges are difficult for customers to understand, since they have few analogs in other industries. The equivalent for car rental would be for the rental company to charge both for miles driven and the maximum velocity at which the car was driven.

[98] PREPA says that "Almost all clients at secondary distribution voltage service have meters with capability for remote reading (daily). In addition, many of these meters can provide for hourly data storage." (CEPR-PC-4-16) These meters do not appear to be suitable for routine billing of time-varying rates.

Demand charges are the legacy of efforts in the late 1800s to reward customers with smooth loads (and hence high load factors) and penalize those with variable loads and low load factors. Since demand charges do not discriminate between load variations that increase system costs and those the decrease system costs, the approximation of time-varying energy rates is very poor.

Demand charges have long been used for large commercial and industrial customers (such as PREPA's GSP, GST, and LIS rates), but they are much less useful than even simple time-of-use rates.

b. PREPA's approach to demand charges

The PREPA proposes substantial increases in the demand charges for the classes that current have those charges. Messrs. Zarumba and Granovsky indicate that this emphasis on demand charges is motivated partly by a belief that fixed costs (*i.e.*, any costs fixed over the year, not varying in the short run) should be recovered through a fixed, non-volumetric charge (for example, see PREPA Exhibit 4.0, p. 5, regarding recovery of the PPCA).

This approach is inappropriate. Many costs in any particular year are largely determined by the cumulative investment and construction commitments in the past. Even though these costs are overwhelmingly fixed over the year, most of them vary with load in the longer term. Hence, these costs are not fixed and should be recovered through rates that vary with usage and encourage customers to reduce and control the usage that contributes to the costs.

c. Deficiencies of demand charges

Demand charges are difficult to avoid and are therefore often grouped with customer charges in the category of "fixed charges," as opposed to the variable energy charges that customers can control. Even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour. This attribute of demand charges erodes the incentive to even try to avoid the charge, since weeks of careful effort can be swept away if the electric water and refrigerator happen to go on simultaneously. Once a customer is aware of having hit a high billing demand for the month, the demand charge offers no reward for controlling load any time that the customer's load is less that that prior demand.

The demand-charge portion of the electric bill is determined by the customer's individual maximum demand. Customers reach their maximum monthly loads at a wide variety of times during the month. Maximum billing demands do not necessarily, or even commonly, occur at the time of the maximum demands on the system, substations, the customer's distribution feeder, or other equipment.

Capacity costs are driven by coincident loads at the times of high system and equipment loads, not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, sub-transmission lines, and transmission lines occur at varying times.[99]

Demand charges provide little or no incentive to control or shift load from those times that are off the customers' peak hours but that are very much on the generation and T&D peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on regional transmission lines, or on the system peak hour. This can cause customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, and/or the generation system.

Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs. For a customer who experiences its maximum summer demands at noon or 9 pm, a demand charge encourages the shifting of load into the afternoon peaks on the generation, transmission and distribution systems. Demand charges do not provide appropriate incentives to conserve, even during high load hours.

Intervenors (e.g., Previdi Direct pp. 9, 15–16; Agrait Direct, p. 19, Kunkel and Sanzillo Direct pp. 3, 32-33; J.M. Gonzalez Direct p. 8; Massess Y Artze Direct, p. 9) correctly observe that demand charges are essentially fixed charges, largely unaffected by distributed generation (particularly solar generation), and thus erode the customer benefits of distributed generation. They also point out that PREPA's proposals to increase demand charges in the GSP and GST (Previdi Direct, pp. 12-18; Glass Direct, p. 22; Gabel Direct, p. 22) rates reduce energy charges and hence the benefits of distributed generation.

CEMEX also correctly observes that the demand charge has a serious adverse effect on its cost of electricity when it is operating sporadically due to low demand for cement (CEMEX Direct pp. 8-9). This is true even if the plant operates at nearly 100% capacity

[99] The potential exceptions to this observation would be (1) customers who are the only user or by far the largest user on its transformer or (2) an industrial or commercial customer so large that its load dominates the load on its feeder (or conceivably a transmission spur). In these cases, the equipment may normally experience its peak load at the time of the maximum demand of the customer. If PREPA can identify tariffs where these conditions apply more often than not, some small demand charge (to cover those limited cost categories) may be justified for those classes.

factor for the days it is used. CEMEX has focused on a serious problem with demand charges, reinforcing my comments in Section VII.C.2, regarding the shortcomings of demand charges.

d. The choice of the demand-billing interval

PREPA uses a 15-minute period to measure peak demand (CEPR-PC-04-34).[100] It is conceivable that some very sharp 15-minute spike occasionally overloads some type of equipment, but most overloads on the distribution, transmission and generation systems are driven by much longer periods of high loads. As discussed in Sections I.E.2 and I.E.3, most utility equipment (e.g., transformers and conductors) is limited by thermal overloads, and equipment sizing and useful life is limited by load levels over a few hours to a day.

PREPA should convert its demand charges to reflect loads over at least one hour, while gradually shifting cost recovery from demand charges to energy charges.

3. Customer Charges

Since very few customers make decisions about whether to be a customer, a charge for being a customer and getting a bill is the least useful of the common charges in giving incentives for customer behavior.

A small category of costs vary directly with the number of customers. They include the debt charge and maintenance costs for the meter itself, the cost of meter reading, billing, service drops (for classes that use a service drop for each customer), and perhaps customer-service costs, such as call centers. In estimating marginal customer costs, Mr. Zarumba also included transformer costs, but the number and size of transformers are determined by the area and load to be served, rather than the number of customers.[101]

I see no justification for increasing customer charges for the general-service tariffs. As I discuss in Section VII.D.1.b, the GRS customer charge should not be lower than PREPA proposes.

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[100] This interval is specified in PREPA's tariffs only for the TOU tariffs. While PREPA promised to correct the other tariffs and "specify the period used for setting billing demand… in the updated J-1 schedule" (CEPR-PC-04-34a), the updated Schedule J still specifies the billing-demand interval only for the TOU rates.

[101] Zarumba and Granovsky suggest that their estimates of marginal customer costs "can be considered 'conservative' because it does not capture the any components of the minimum distribution system." (Exhibit 15.0, page 7). This alleged conservatism does not exist, since the cost of the distribution system is determined by demand and the area that the system must cover, not the number of customers per mile.

4. Connection Fees

In CEPR-RS-01-14, PREPA revealed that its estimate of "Customer Service Improvement Savings" in Schedule B-3 included an increase in charges for reconnecting service, apparently for customers who were disconnected by PREPA for being in arrears (or perhaps between tenants in a building).

> Savings are based on charging higher costs to customers for reconnection service beginning January 2017. Currently low consumption customers (480V and below) pay $25 to reconnect service and it costs PREPA $52 to reconnect service. Similarly, high consumption customers (>480V) pay $100 for a reconnection and it costs PREPA approximately $500 to reconnect those customers. PREPA is proposing to increase reconnection rates to $75 for low consumption customers and $750 for high consumption customers; the change should lead to additional collections of approximately $10mm per year. (CEPR-RS-01-14)

In CEPR-RS-05-21(d), PREPA provided the derivation of the reconnection costs of $52 for secondary customers and $509 for primary customers. PREPA's explanation for charging about 50% more than the cost of reconnection was as follows:

> The $75 per reconnection charge was suggested for two reasons, (i) that charge covers PREPA's costs, (ii) a higher reconnection charge encourages customers to pay bills on time (so late customers can avoid the penalty). On average, PREPA reconnects 70% of the customers suspended in any given month, most within the next 48 hours (CEPR-RS-05-21, parts d and e).[102]

Increasing the reconnection fee to full cost is reasonable. Charging 50% more than cost is not reasonable. PREPA's justification for the overcharge is essentially a desire to punish customers who pay late. If PREPA believes that a late-payment charge would be appropriate to reflect associated costs, it should propose a cost-based late charge, independent of whether the customer is disconnected and reconnected. A charge for reconnection (like the late charge) will likely fall disproportionately on those least able to pay the additional costs, essentially as a tax on poverty or financial distress.

The Commission should limit the reconnection charge to $50 for secondary customers and $500 for primary customers, and order PREPA to seek advanced Commission approval for any future changes in fee schedules.

D. Tariff-Specific Rate-design Issues

PREPA has about 17 tariffs. Rate designs proposed in Exhibits 4.0 and 15.0 reflect decisions about distributing the proposed rate increase across the billing determinants (*e.g.*, customer months, energy use, maximum demand) in each of those tariffs, and sometimes other changes in the rate structure.

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[102] PREPA does not explain the similar over-charge for the primary reconnections.

1. Residential

a. Low-income discounts

PREPA has three residential tariffs—LRS, RFR and RH3—that discount charges to residential customers on the nutritional assistance program, in public housing owned by the Public Housing Administration, and municipal public housing, respectively.

The LRS and RH3 discounts from GRS would be entirely in the first 425 kWh. The legislatively determined RFR tariff charges a fixed price for a fixed block of monthly energy (with the quantity determined by the number of rooms in the housing unit). The second-block rate for LRS, RH3 and RFR (above the fixed-price block) would be the same as the general residential GRS rate. That treatment is reasonable; no intervenor raised concerns about the pricing of electricity for large low-income customers.

b. The GRS customer charge

The customer charge is imposed on every customer every month, regardless of consumption. If possible, the fixed charge should reflect the cost of having that household (in the case of the residential class) as a customer, even if the customer used zero energy. Stated a bit different, the fixed charge should approximate the cost of adding a customer without adding load, or the savings when a customer notifies PREPA that service is no longer required. For example, if a large house is divided into four condominiums, but total energy consumption does not change, most costs will remain the same, but some costs will increase by a factor of four (like the costs of postage for the bills). The fixed customer charge should reflect the minimum costs of serving the smallest customers in the class; to the extent that fixed monthly costs are higher for larger customers, those costs should be collected through usage charges, so they will be borne by the larger customers but not the smaller ones.

In general, the fixed costs of serving a customer is limited to the costs of the service drop, meter, meter maintenance, meter reading, billing, and customer service. With PREPA's remote meter-reading technology, the incremental meter-reading cost is very small. The incremental or decremental cost per customer for customer service and billing (other than the printing and postage) are likely to be much less than the average cost, as well.

In its initial filing, PREPA proposed eliminating the existing residential customer charges, on the assumption that there would be a fixed Transition Charge. The Commission's order requiring a per-kwh Transition Charge was issued after PREPA made its initial filing. In its supplemental testimony, PREPA proposed a fixed customer charge, raising the GRS fixed charge from the current $3/month to $8/month, while leaving the RH3 and LRS customer charges at $2/month.[103] GRS PREPA maintains that

[103] The RFR charges for fixed blocks of energy (based on number of rooms in dwelling) are set by law, in Act 69-2009 as amended by Act 22-2016.

the full fixed costs of serving a customer who uses no energy is $14.18/month for single-phase customers, which would include most residential customers and all small customers (Exhibit 15.0, p. 6), based on the marginal-cost study.

PREPA's estimate of the marginal customer cost for a single-phase residential customer is $14.18/month, comprising carrying charges of $4.60 for the meter, $2.94 for the service drop, and $5.25 for a share of a transformer, plus $1.38 for meter reading and billing. This cost estimate is overstated for a new minimal-usage customer, due to the following errors:

- PREPA used a nominal carrying charge of 17.06%, rather than a real carrying charge of 15.26%. Since PREPA will be escalating this estimate over time, the real carrying charge is appropriate here. Correcting that error reduces the marginal customer charge to $12.83/month.
- The assumed capital cost includes $370 for a transformer. Transformer costs are driven by the size and number of transformers, both of which are determined largely by load levels. Adding a customer without adding load will not normally require a new transformer. PREPA's cost-of-service study treats transformers as entirely load-related; the marginal cost study should do the same. Correcting this error reduces the customer cost to $8.92/month with the nominal rate, or $8.13/month with the real rate.
- The capital cost also includes $207 for a service drop. As I explain in Section II.I, small customers in apartment buildings will usually share a service drop. Assuming that an average of just five small residential customers share a larger service drop sized for general-service customers would reduce the marginal customer cost to $6.69/month with the nominal rate or $6.13/month with the real rate.
- The meter cost of $323 also appears to be quite high. This cost may be for a smart meter, and would be lower for a new conventional meter.

So the cost to connect, bill, and service a new small customer would be about $6/month.

The costs avoided by encouraging an existing customer to cease service would be even lower. If service is discontinued because the residence is temporarily vacant, PREPA would save only the billing and metering expense of about $1.38/month. If the property is permanently abandoned or the service is merged (as when two apartments are combined or an outbuilding is connected to the house), PREPA may retrieve the meter, but will not be able to salvage the original installation cost and will incur a removal cost. In any case, the meter will probably be an older, less-expensive unit, costing much less than $323. PREPA is unlikely to remove and recycle the service drop, especially if the service drop is shared with several other apartments. Depending on the value of the meter and the cost of removal, the marginal cost of maintaining an existing location might be $2 or $3. And most of the choices about incurring customer costs are choices for existing locations.

Hence, more realistic estimates of the marginal customer-related cost for a small residential customer are on the order of $1.38 to $6.13/month. These estimates do not support PREPA's large proposed increase in customer charge to $8/month. Based on the corrected marginal-cost analysis, a reasonable residential customer charge would be in the range of $3 to $4/month. Any increase in the customer charge reduces the portion of the allocated revenue available for the energy charge and thus the customers' conservation incentive.

I recommend that the Commission set the GRS customer charge at $4/month. In its compliance filing, PREPA should compute GRS energy charges to recover the remainder of the revenue allocated to this class.

c. GRS increasing blocks

Currently, PREPA charges GRS customers 4.35¢/kWh for the first 425 kWh of monthly consumption and 4.97¢/kWh for additional usage. This inclining-block rate structure is commonly used to reduce charges to small customers and to reflect differences in costs between small and large customers.

PREPA proposes to flatten the energy rate, removing the small increase at 425 kWh/month. Navigant asserts that "No rationale exists for the inverted energy charge. The energy charges, for both the first and second blocks, are significantly in excess of the bundled marginal cost" (Ex. 4 at 41). This argument relies on the understated energy and demand charges from the marginal cost study, which I describe in Section IV.

In addition, PREPA's load data (in Schedule G) indicates that the GRS customers using over 425 kWh monthly have a lower load factor (fewer kWh per kW of NCP peak) than the smaller GRS customers in the GRS 111 tariff code, so larger GRS customers may be more expensive to serve per kWh than small customers.[104] Eliminating the inclining-block rate would slightly reduce conservation incentives for the larger customers, who probably have more opportunities for conservation. It would also send a signal that the Commonwealth's energy establishment is ambivalent with regard to encouraging energy efficiency.

The future of the inclining-block rate in the GRS tariff should be retained in this proceeding and reconsidered in the rate-design proceeding.

[104] As I explained in Section II.E, NCP is not the best measure of peak load, especially for generation and transmission, but that is the only peak measure PREPA presents.

d. Fuel discount

The legislature has mandated a fuel discount of as much as the cost of $30/bbl oil, to be applied to the first 400 kWh monthly usage of eligible residential customers. (Puerto Rico Electric Power Authority Act, §22(c), as amended by Act 133-2016).[105] PREPA has applied this discount to customers in the LRS and RH3 tariffs and the GRS 111 tariff code (which covers the handicapped, the elderly and college students), using a complicated formula that gave higher discounts per kWh to the smallest customers. The existing system uses a complicated declining discount, starting at 90% for the smallest customers, falling to 75% over 100 kWh/month, 65% over 200 kWh/month, and 55% over 300 kWh, with the discount for 400 kWh continued through 425 kWh and the entire discount disappearing at 426 kWh/month. This discount includes steep drops in the subsidy at 101, 201, and 301 kWh.

In this proceeding, PREPA proposes to simplify the discount to 60% of the ceiling discount, or $18/bbl, which PREPA estimates to be equivalent to about $2.91/kWh in 2017 (CEPR-PC-03-028, CEPR-PC-04-46 Attachment 1).[106]

PREPA has proposed to simplify the formula, by using the average current discount, 64% of the 2.91¢/kWh, or 1.86¢/kWh.[107] (CEPR-PC-04-46)

This simplification is reasonable, assuming it is consistent with the legislation. Using the averaged discount, rather than the existing schedule, increases the bills for customers under 300 kWh, but by no more than 76¢/month, and decreases bills for larger customers, by as much as $1.05/month for customers from 400 to 425 kWh.

I am more concerned by PREPA's continuation of the abrupt withdrawal of the discount at 425 kWh. This practice make the effective price of the 426th kWh in any month $7.45 plus the full applicable retail energy rate. This is a very large penalty for a very small change in usage. The legislation requires the discount up to 425 kWh, but I do not see any prohibition on extending the discount beyond 425 kWh. If the Commission is able to

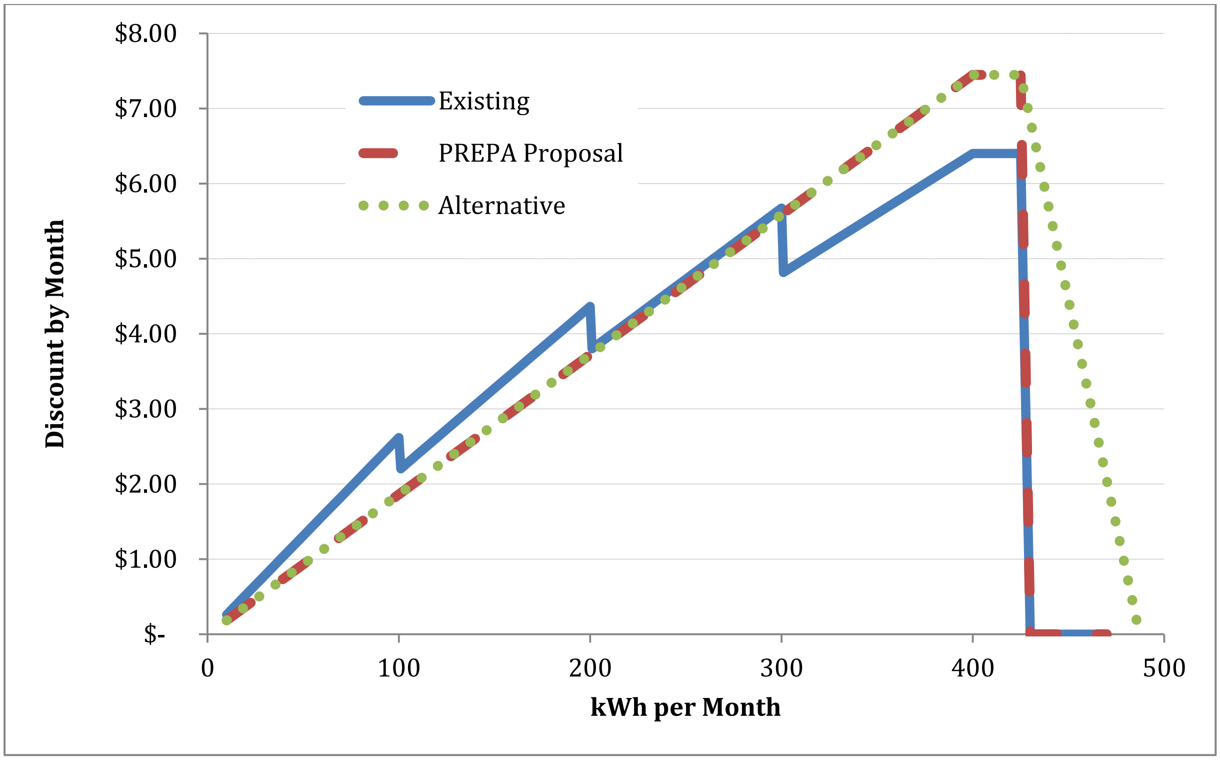
[105] The law does not specify how the discount should be converted from $/bbl to ¢/kWh.

[106] The ¢/kWh values provided in CEPR-PC-03-28 are not consistent with the total dollars and kWh values for this discount reported in CEPR-PC-01-026. Nevertheless, the values are roughly equivalent to the $18/bbl, divided by about 6.3 MMBtu/bbl and multiplied by a heat rate of about 10,200 Btu/kWh, all of which are plausible assumptions for PREPA's fuel use.

[107] Zarumba and Granovsky (Exhibit 4.0, pp. 37–38) report the average discount as 66% (and hence the customer's payment as 34% of the full fuel cost). PREPA calculated the correct discount (64%) in response to CEPR-PC-04-046a on August 24 and promised the "a piece of errata that will be filed shortly." Yet Schedules J-3 Rev and J-1 Rev (filed October 13) repeat this error, and Exhibit 15.0 does not address it.

extend the discount to about 490 kWh, it can smooth out that drop, as illustrated in Figure 7.

Figure 7: Monthly Fuel Subsidy by Usage Level



PREPA says that "The fuel oil subsidy is reflected in customer bills as a separate dollar credit line item" (CEPR-PC-03-026) and that it intends to continue this practice (CEPR-PC-03-027). That is a workable approach. Including the discount in the base rates for LRS and RH3, by reducing the energy charge for the first 425 kWh, might be clearer for customers. Doing the same for the GRS 111 customers would require that the GRS tariff be split into two rates. Those potential changes would be better considered in the subsequent rate proceeding.

e. Direct debit credit

PREPA has for some time provided a 10% discount on the "basic rate" (excluding fuel and purchased power), for residential customers who arrange for automatic payment of their electric bills. PREPA has been unable to provide any rationale for the level of this discount and has no estimate of the actual savings due to direct debit. (CEPR-PC-04-27)

The primary value that direct-debit billing provides to the utility would be increased probability that bill payments will be received on time and paid in full. If a customer goes into financial distress, the bank balance may be insufficient to cover the bill, so the direct-debit billing offers PREPA limited security. There will still be a lag from consumption to payment, although it will be shorter with direct debit. As PREPA put it, the benefits to PREPA are that direct debit:

i. Reduces the utilization of checks as a payment option, which reduces processing costs;

ii. Improves cash-flow, since the payment amount and date can be projected with more certainty; and

iii. Reduces payment delays (CEPR-PC 04-27)

Whatever the benefits to PREPA of prompt, reliable and efficient payment, those benefits should be the same for all components of the bill. The direct debit credit has been about 2% of the total bill, since the base rate has been 20 % of the total residential rate. Setting the credit at 2% of the total bill would roughly maintain the status quo, while varying the discount in proportion to the bill, as various components change. The 2% discount would also be consistent with the discounts offered by other utilities.

The direct debit discount, along with all other available discounts, should be enumerated in PREPA's tariff book, yet it does not appear in PREPA's Schedule J.

Regardless of the specific value of the direct-debit discount, it is a voluntary rate provision intended to reflect savings to PREPA, and should not be counted as a subsidy.

2. General Service

a. GSS

Navigant proposes an increase in the GSS customer charge from $5 to $10, with the remaining revenue recovered through energy, as it is now. The GSS rate is very broad, since it includes all non-residential customers served at secondary, which might range from a street kiosk to substantial stores and offices. The rate is limited to 50 kVA of load (it is not clear how PREPA measures the peak load of the GSS customers), and customers larger than that level may be forced onto the GSP primary rate. Most utilities have rates for GS customers of any size served at secondary, and impose more sophisticated metering on secondary customers over a threshold of 10 kVA or so. Navigant would like to break GSS into two or more tariffs, but does not suggest any particular redesign and apparently does not have the data needed to support such a design.

b. GSP and GST

For the GSP, GST and LIS tariffs, PREPA proposes to dramatically increase demand charges. The percentage increases in the demand charges are more than twice the increases in the energy charges, and for GSP, over twelve times.

Demand charges do not reflect cost causation, since they charge for usage at the customer's maximum load, not necessarily at times of high load for the system or any part of the distribution or transmission system. The Commission should reject PREPA's proposal to increase demand charges. The demand charge does not charge for usage at CP, or even at NCP, only at the customer's maximum load, whenever that occurs.

The revenue increases assigned to the GSP and GST tariffs (and related special tariffs) in this proceeding should be recovered through increases in the energy rates. The demand charges should be left at the present rate for each tariff. Further rebalancing of the energy and demand charges can be considered in the rate-design proceeding.

c. Demand ratchets

Currently, most PREPA tariffs with demand charges determine billing demand each month as the highest of (a) the current month's maximum 15-minute demand, (b) 60% of the customer's maximum demand in the preceding year (called a demand ratchet, since it prevents the billing demand from declining), and (c) 60% of a previously established contract demand level. Messrs. Zarumba and Granovsky propose to eliminate the ratchets and contract demands, because they are "extremely complex" and no cost justification exists to support their further use (CEPR-PC-04-31), which I understand to mean that PREPA could not find any documentation of its decision to impose the three-part billing demand.[108] Thus, the demand-charge portion of the customer's bill would be determined solely by the current month's maximum demand.

I agree with this proposal, not for the reasons suggested by the Navigant panel, but because the ratchets and contract demand make it more difficult for customers to control their bills and dilute incentives to reduce usage in ways that would reduce PREPA's costs.

The demand charges in $/kW-month should not be increased to offset any reduction in billing demand due to the change in definition. Any rate increases for normal general-service customers should go into the energy charges.[109]

d. Existing TOU Rates

For both the existing non-residential time-of-use rates (TOU-P and TOU-T), PREPA proposes to

- put almost the entire rate increase into more than doubling the demand charges,

[108] Messrs. Zarumba and Granovsky should have been able to analyze the billing demand structure on its merits, independent of decades-old PREPA documentation.

[109] The one exception I would make to this rule would be for the PPBB tariff, which is a backup tariff.

- eliminate the existing distinctions between on-peak and off-peak demands,
- slightly reduce the energy charges, and
- close the rates to new customers.

For the two customers currently on the TOU-T rate with standby service (SBS), PREPA proposes to terminate their TOU rates and onto move them onto the non-TOU GST tariff.

The proposal to shift revenues from TOU energy rates, which can reflect the variation in short- and long-run costs, to demand charges, which do not, is ill-advised.

The Commission should keep these rates (TOU-P, TOU-T and SBS TOU-T) open, without increasing demand charges, and indicate that the rate-design proceeding will consider the structure of the existing TOU rates, expansion of TOU rates to additional customers, and moving customers with adequate metering to rates that vary with system conditions, such as dynamic or real-time pricing.

The rate-design proceeding should consider a range of issues regarding time-of-use rates, including seasonal variation in rates (which can apply to all tariffs) and variation during the week and the day (which is limited to customers with adequate metering).

PREPA does not current vary its rates between seasons. Messrs. Zarumba and Granovsky express skepticism about whether any seasonal differentials in costs exist (Ex. 4.0, pp. 16–17). The data they provide suggests that peak loads are higher in in June–October, but at least for generation, maintenance requirements appear to levelize the reliability risk over the year. This issue should be explored further in the rate-design proceeding.

The structure of the analyses that Messrs. Zarumba and Granovsky offer regarding the timing of peak loads (among seasons and among the hours of the year) is unlikely to produce useful results (PREPA Exhibit 4.0, pp. 16–17 and PC-01-42 Attach 1). They report the probability of each month or hour having a load that "will equal or exceed the peak" month or hour. Of course, no load can exceed the peak load, so these analyses are suspect to begin with. More significantly, Messrs. Zarumba and Granovsky report that the probability of meeting or exceeding peak totals 935% over the months and 1,052% over the hours of the day; these are not meaningful concepts.

I have identified some of the detailed conceptual problems with the Navigant analyses, but those are largely irrelevant, since the results are inconsistent with reality. PREPA has no rationale for closing the TOU rates. There are clearly a lower peak load in the afternoon, followed by a higher peak in the late evening. Messrs. Zarumba and Granovsky claim that uncertainty about changing load patterns precludes design of appropriate TOU rates (PREPA Exhibit 4.0, p. 22–23) and that "information in this proceeding indicates that PREPA cannot practically expand TOU rates—at least in many circumstances—due to metering and billing issues" (PREPA Exhibit 24.0, page 8). While it is not clear to what information Messrs. Zarumba and Granovsky refer, I do not find that any of these assertions should result in closing the existing rates.

CEMEX recounts its efforts to switch to a time-of-use rate, to reduce the cost of operating at varying levels over the course of the month. PREPA should not have refused CEMEX's proposal to change to a posted rate, especially one that encourages more efficient operating patterns. PREPA's efforts to close TOU rates to new customers, and to force some customers off TOU rates, are not warranted.

In short, PREPA should keep the current TOU designs open, and warn the customers that periods and price differentials may change in the rate-design case.

e. Economic-development and load-retention discounts

PREPA proposes that it be allowed to offer price discounts through an "economic development rider [that] would provide a negotiated discount for a period of three to five years in exchange for creating new jobs on the island" with the level of discount [to] be negotiated and driven by the level employment created and the cost to serve the load," as well as a load-retention rider to respond to "a threat of loss of load" with a negotiated rate to compete with the customer's alternative.[110] The load-retention rider would not be tied to job retention; prices would be set to maintain some revenue above PREPA's estimate of marginal costs.

If an opportunity arises for PREPA to offer a discounted rate to retain load that would otherwise be lost, while still generating revenues greater than the cost of serving the load, that can reduce rates for other customers. The same is true for opportunities to add load that produces revenues in excess of the costs, again reducing the revenue requirements for other customers.

PREPA proposes that application of either of these riders be subject to CEPR approval, which is the standard practice in other jurisdictions, and necessary to ensure just and reasonable rates to the customers who will have to pay for the costs not recovered from the discounted customer. . The Commission should establish some guidelines for PREPA in the use of these riders, which should not become a widespread subsidy for industrial customers at the expense of residential and commercial consumers. Those guidelines may be developed in a future rate case, in the rate-design case, in other dockets (such as the performance proceeding) or a combination thereof.

[110] Zarumba and Granovsky discuss load retention to counter bypass, which would presumably involve alternative generation resources. It is not clear whether PREPA would attempt to use the rider to retain industrial facilities facing global competition.

Rate discounts for large customers should not result in rates that charge less than marginal cost, charge less than the customer would have been willing to pay, or encourage wasteful consumption.

Industrial discounts can make sense, if:

1. Rates are higher than marginal costs over the period of the discount.
2. The discount keeps the total rate above marginal costs, so that the businesses that open or stay open are not increasing costs to other customers.
3. The discount is structured to encourage efficient use of energy, by keeping the energy charges close to the standard rate for the class.
4. The discount is only available when an objective analysis indicates that the load is likely to be lost (or not materialize) without the discount. Ideally, other departments within the government of Puerto Rico would be involved in determining whether the customer's economic viability requires the rate discount.
5. The discount is tied to engaging in any applicable energy-efficiency program.

The Commission should alert PREPA that these (or similar) conditions will be applied rigorously in review of proposed rate discounts.

As discussed in Section IV, PREPA's estimates of marginal costs appear to be understated. PREPA will need to improve those estimates before the Commission can have confidence that increased sales due to any discount will benefit other customers.

A more difficult issue arises if PREPA asks the Commission to discount rates below costs to achieve some goal beyond PREPA's mandate, such as creating jobs. Neither the Commission nor PREPA has any particular expertise or authority with respect to employment. The Commission should be reluctant to approve any such discount without specific legislative instruction and technical expertise from the Commonwealth's economic-development agencies.

f. The PRASA preferential rate

Act 50-2013 set a preferential rate for the Puerto Rico Aqueduct and Sewer Authority (PRASA, or AAA), setting the rate at 22¢/kWh for FY2014 to FY 2016, and16¢/kWh for FY2017 and beyond. PREPA asserts that the Act also allowed PREPA to suspend the preferential rate, which PREPA has done, resulting in no claimed subsidy for PRASA in FY2017.

PRASA has requested that the Commission reinstate the preferential rate, on the grounds that the preferential rate is not a subsidy; that it has stabilized PRASA's costs, allowing it to prepare more accurate budgeting purposes; and that the cost reduction allows PRASA to develop needed wastewater and sewer projects. (Rivera Direct, p. 2).[111]

Mr. Rivera says that the preferential rate was implemented to reduce PRASA's high energy costs, representing 25% of PRASA's annual operating costs, when its projected budget deficits ranged between $340 million and $529 million for FY2014–2018. PRASA forecasts that the removal of the preferential rate for 2017 will increase its energy costs by roughly $50 million annually.[112]

PREPA's projection (in CEPR-PC-01-026) of the difference between PRASA's FY 2017 electric bills at the statutory preferential rate and the normal general-service rates is small. But that estimate depends on (1) PRASA's FY2017 energy consumption being just 3% of its energy use for FY 2016 and FY 2018, and (2) the fuel costs being as PREPA projected them. Any fixed rate that does not reflect changes in fuel prices may become a very large subsidy if fuel prices rise. The only other tariff with a fixed energy change and no fuel adjustment is RFR, for the initial blocks.

In this proceeding and the rate-design proceeding, PRASA and PREPA may be able to provide the Commission with information about PRASA's operations that will clarify whether PRASA load is less expensive to serve than the load of the other general-service customers.[113] The Commission can also weigh the consumer burdens of higher PRASA rates (if PRASA does not receive special rate treatment) versus higher PREPA rates (if PRASA bills are reduced by reimposition of the statutory 16¢/kWh rate or some compromise arrangement).[114] As better load data become available, the Commission may be able to reach a better-informed judgment about PRASA's rate treatment.

3. Lighting and unmetered rates

PREPA has proposed a large percentage rate increase for the Public Lighting and most unmetered tariff codes.[115] Messrs. Zarumba and Granovsky assert that "Public Lighting

[111] I do not understand the distinction that Mr. Rivera's distinction between a preferential rate recognizing the customer's financial distress and a subsidy.

[112] The magnitude of this difference depends on actual fuel costs.

[113] Pumping and treatment plants are likely to have better load shapes than typical customers in their classes, but offices and other facilities may be typical GSS and GSP loads.

[114] These issues are also discussed in the report of Ralph Smith and Mark Dady.

[115] Messrs. Zarumba and Granovsky say that "Tariff USSL is PREPA's tariff for unmetered services" (PREPA Exhibit 4.0, page 57). But the USSL tariff serves less than 1% of PREPA's unmetered load.

is a subsidized class, and therefore required a redistribution of the overall revenue requirement." (Exhibit 4.0, page 25) PREPA acknowledges that "increasing the rates for the Public Lighting tariff would [increase] the magnitude of the subsidy charge. However, the alternative would be to mitigate the increase to Public Lighting which would require larger increases to other customer classes." (CEPR-PC-11-02b)

PREPA essentially asserts that increasing the subsidy charge is preferable to increasing base rates to cover the costs of the legally subsidized public-lighting and unmetered rates, but has offered no basis for that position.[116] PREPA has not provided revenue computations (or even tariffs) for the public lighting and unmetered rates, so it is not clear how the revenues at current and proposed rates, or how the fact that most public-lighting customers are not billed affects the revenue projections.

I recommend that the Commission increase all components of the Public Lighting and unmetered tariff codes at the average increase for the tariff in this proceeding. These issues should be revisited in the rate-design proceeding.

VIII. Distributed Generation and Net Metering

A. Background

The term "distributed generation" refers to relatively small generation resources connected to the distribution system.[117] Some of these facilities are free-standing facilities that sell power to the utility, but an increasing number of distributed generators throughout the developed world are located behind customers' meters. Solar photovoltaic systems represent most of those installations.[118]

For a number of reasons, including administrative convenience, regulators have allowed customers to use the energy from small solar facilities to reduce the customer's billing determinants (usually monthly metered energy), in an arrangement known as net metering.[119] When the solar facility produces more energy than the customer uses in a

[116] In the October 31 conference call, Mr. Zarumba suggested that pushing more costs into the subsidy charge would have the salutary effect of raising public discontent with the level of subsidies. The Commission should consider whether it shares that political agenda.

[117] Sometimes, the term includes small units connected to the transmission system close to load.

[118] Other behind-the-meter distributed generation is wind or combined heat and power.

[119] In some cases, other renewable technologies, such as wind, and small combined heat and power facilities are also eligible for this treatment. In principle, the behind-the-meter distributed generation could reduce the customer's billing demand (for those customers with demand charges), but billing demand is difficult to reduce.

month, the excess energy is carried over as a credit against usage in future months, with each excess kWh valued at the energy rate in the tariff under which the customer is served. Excess generation over the course of the year is often credited at a lower rate.[120]

Puerto Rico has allowed net metering for behind-the-meter renewable generation since 2007 (Act 114-2007). The law applies to residential systems with capacity up to 25 kW and non-residential systems up to one MW. The law allows for customer net excess generation to be carried over as a kWh to the following month, but the credit is limited to a daily maximum of 300 kWh for residential customers and 10 MWh for commercial customers.[121] The Legislature further strengthened its support for renewable energy generation by enacting the Green Energy Incentives Act (Act 83-2010), establishing Renewable Energy Credits ("RECs"), creating a $290 million incentive fund and providing for economic and tax incentives. The recently enacted Electric Power Authority Revitalization Act (Act 4-2016) provides for increased transparency in the net metering credit and supports charges that are not excessive or unduly burdensome on net metering customers. Specifically, the Electric Power Authority Revitalization Act (Act 4-2016, Section 29) provides that:

> The Electric Power Authority may propose, as part of its rates, just and reasonable charges to its net metering customers. The Energy Commission shall evaluate said charges as part of the rate proposal of the Authority.
>
> The Energy Commission shall evaluate and determine which charges shall apply to net metering customers, such as the Contribution In Lieu of Taxes, Securitization, Subsidies, and Grants. Both the Authority and the Commission shall take into account the following criteria when proposing and evaluating the net metering customer charges:
>
> i. The charge to be billed shall be just and shall have the purpose of covering the operating and administrative expenses of the grid services that receives any customer that entered into a Net Metering Agreement. The grid services received by a net metering customer shall be clearly differentiated from the services that the Authority bills on a regular basis to all of its customers.
>
> ii. The charge shall never be excessive or established in such a manner as to constitute an obstacle to the implementation of renewable energy projects.
>
> …

[120] The details in these arrangements vary among jurisdictions.

[121] In another effort to increase renewable generation, Act 211-2008 reduced the stringent meter requirements to encourage greater participation.

> The Authority may not bill additional charges or increase the monthly energy usage rate to any customer that choses to connect a solar energy system, windmill, or other renewable energy source to the transmission and distribution system of this public corporation. (Section 29, amending Section 4 of Act No. 114-2007)
>
> "The Electric Power Authority may bill a customer for the net electricity supplied, as well as the charge to be approved by the Energy Commission in accordance with Section 4 of this Act.
>
> In those cases in which a customer feeds back to the Electric Power Authority more electricity than it supplied to the customer during a billing cycle, the Electric Power Authority may charge the customer a minimum monthly service fee not greater than that which it charges to other regular customers that do not consume electricity during a billing cycle.
>
> For the billing cycle closing in June of each year, any excess kilowatt-hour credit accumulated by the feedback customer during the previous year and which remains unused shall be compensated as follows:
>
> 1) Seventy-five percent (75%) of the excess shall be purchased by the Electric Power Authority as provided by the Energy Commission; and
>
> 2) The remaining twenty-five percent (25%) shall be assigned to the Electric Power Authority to be distributed as a credit or reduction in the electricity bills of public schools.

PREPA proposes to significantly reduce the benefits of net metering for new behind-the-meter renewable generation, by increasing customer charges (which would not be reduced by net metering) and charging the CILT and Subsidy charges on both the energy provided by PREPA and the energy provided by the customer's generator.

I understand that the Commission is planning to initiate a proceeding on the rates and rules for net metering. Any sweeping redesign of distributed-generation ratemaking should be addressed in that proceeding.

B. Ratemaking for distributed generation

Within the legislative constraints, the Commission has the challenge of encouraging distributed generation that is environmentally and economically desirable, while maintaining at least rough equity in the billing of customers with and without distributed generation and preventing uneconomic bypass. The Commission should review ratemaking options in terms of the following main criteria:

- Recognition of all system costs and benefits. Distributed generators affect several aspects of the costs of serving the host customer and other customers. The question before the Commission is whether the payments by customers with distributed generation pay adequately for their usage of utility services.

- Simplicity and consumer understanding. The short- and long-term implications of the net metering ratemaking approach should be clear, so that customers, installers, and other market participants can make informed decisions regarding long-term cost commitments.
- Effectiveness of rate design in encouraging efficient consumer choices. Any modifications of rate design to accommodate net metering should be designed to increase, rather than reduce, incentives for customers to use electricity efficiently.

The system benefits of distributed renewable generation for Puerto Rico include:

- Avoided generation variable costs, particularly fuel.
- Avoided generation fixed costs, including the reduced investments for capacity, fuel-cost reductions, and environmental compliance.
- Avoiding the costs of acquiring centralized renewables.[122]
- Reduced transmission and distribution line losses.
- Avoided load-related transmission upgrades.
- Avoided load-related distribution upgrades.
- Reduced wear and tear on transmission and distribution equipment.
- Reduced environmental effects, including emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), oxides of nitrogen (NOx), air toxics, and fine particulates; along with fines imposed by environmental regulators for violating rules and standards.

Some of these benefits are captured by the customers hosting distributed generation. They reduce their bills, which would include average generation energy and capacity costs, average line losses and embedded T&D costs. Since photovoltaics provide more energy in on-peak than in off-peak hours, particularly in the summer, solar net-metering generation (whether it reduces the customer's load or feeds back into the distribution system to serve other nearby customers) will tend to reduce average costs in most of these categories, benefiting other customers. Customers as a whole benefit from the avoided generation, transmission and distribution upgrades, reduced wear and tear, the reduction in percentage line losses, and reduced environmental effects.

[122] PREPA has been signing contracts for utility-scale solar facilities at prices comparable to the full retail rates for some classes.

1. PREPA perspectives

PREPA's discussion of distributed-generation ratemaking (Exhibit 4.0, pp. 30–35; CEPR-PC-03-05, 03-06, 01-28) is sometimes difficult to follow, since the testimony and discovery responses sometimes use the term "distributed energy resources" (DER) to refer to both renewable generation eligible for net metering (NM or NEM) and other distributed generation, sometimes just to non-renewable distributed generation, just to net metering customers, or to net-metered solar generation. Any particular reference to these topics must be read in context, to determine which categories of generation intended.

I read PREPA testimony as accepting that customers' behind-the-meter distributed renewable facilities will be eligible for net metering, due to the legislative language defining net metering and encouraging development of renewables. PREPA intends to pursue future opportunities for decreasing payments for energy delivered to PREPA and requiring NEM customers to pay for transmission and distribution services they do not use (Exhibit 4.0, p. 35). And even in the short term, PREPA proposes to charge net-metering customers for costs they do not currently pay, including the CILT and subsidy charges for their generation output.

PREPA's rationale for its positions comprises at least two areas: the argument that solar distributed generation does not reduce any fixed costs, and the assertion that PREPA's cost-of-service study supports much higher charges for net-metering customers.

First, Messrs. Zarumba and Granovsky assert that "Many of the DER technologies which are being installed (e.g., photovoltaic) are intermittent in nature and therefore needs firm capacity to back up the service provided by these units." (Exhibit 4.0, p. 31) This complaint represents a misunderstanding of utility planning and cost causation. As I explain in Section I.E.1.b, generation capacity is driven by probabilistic loss-of-load considerations; whether solar, wind, or other variable generation resources helps reduce capacity requirements depends on whether it reduces load at times that contribute to the annual loss-of-load risk. All generation is "intermittent," in the sense that it is sometimes unavailable.[123] Similarly, whether variable distributed generation helps reduce the costs of transmission and distribution capacity depends on the extent to which the T&D equipment peaks at the times the generation is available, as well as the extent that the generation helps unload the equipment prior to the peak, reducing damage from overheating (see Sections I.E.2. and I.E.3).

Messrs. Zarumba and Granovsky acknowledge the legislative mandate for supporting the development of renewable energy. "PREPA faces a different legal standard from [sic] renewable resources. In brief, PREPA is required to support the development of these

[123] This is particularly true for PREPA's fossil resources, many of which have forced outage rates over 10%, with some as high as 20%.

resources. We therefore propose a full credit equal to each customer's energy charge (excluding CILT, Subsidies, and Securitization)." (Exhibit 4.0, p. 34)

PREPA's support for even this limited treatment of net metering is reluctant, at best.

> The current NEM pricing policy should not be continued in the future. The policy is providing compensation to customers for the unbundled cost of transmission which has a marginal cost of zero and the unbundled cost of distribution which has a marginal cost which is less than the avoided cost. These network costs should be non-bypassable. NEM customers are using these systems but allowed to avoid payment for these assets. The current policy will not provide for the economic sustainability of PREPA and triggers cross-subsidies to other customers. (Exhibit 4.0, p. 31)

In several jurisdictions with net-metering penetrations considerably higher than Puerto Rico, regulators have rejected complaints similar to PREPA's and continued net metering, with minor changes to the net-metering compensation. Examples include California (Rulemaking 14-07-002, Decision 16-01-044, January 28, 2016), Vermont (Revised Rule 5.100 Pursuant to Act 99 of 2014, June 30, 2016), and Massachusetts (Chapter 75 of the Acts of 2016).[124]

Second, Messrs. Zarumba and Granovsky assert that "Customers without DER are subsidizing customers with DER" (Ex. 4.0, page 31) and "In Tariff GRS…the total subsidy for NEM customers is $0.07086/kWh,… representing a 79% premium which would need to be recovered from other customers." (Exhibit 4.0, p. 34) Those assertions are based on conclusions about the costs allocated to net-metering customer in the COSS. As I described in Section I.F and Section II, the COSS has a number of serious problems, particularly the following:

- Understating the energy-related portion of fixed generation costs (PREPA fossil, AOGP, and the IPP charges).
- Allocating fixed costs of generation, transmission and most distribution on NCP demand by tariff code, which tends to arbitrarily penalize small tariff codes, including the net-metering codes.
- Assuming that solar net metering does not reduce the need for any type of capacity, even though significant portions of the T&D system peak in the middle of the day.[125]

[124] A couple jurisdictions have made substantial changes to their net-metering regimes, particularly Hawaii (which has a very high penetration of distributed solar) and Nevada.

[125] See Section I.E for a detailed discussion of the timing of T&D peak loads.

- Allocating the overstated demand-allocated costs to each net-metering tariff code based on PREPA's estimate of that group's highest NCP for the year, and comparing that value to that tariff code's FY2014 revenues.[126]

The last point is important because the number of customers with net-metering in some tariffs (such as GRS) rose rapidly during FY2014, the NCPs in the late months of FY2014 (April to June) reflect more customers than do the annual revenues. As a result, the lower average number of net-metering customers appear to be underpaying for the peak loads of the higher number of customers late in the year.

For example, PREPA estimates that the GRS 112 net-metering customers experienced their FY2014 NCP in June 2014, the last month of the fiscal year. In that month, PREPA reports that the net-metering load had grown 34% since October 2013, when PREPA estimates the rest of the GRS 112 customers experienced their NCP. As a result, PREPA allocates the GRS 112 net-metering code about one third more demand-related costs, due to the growth in net metering during the year.

Messrs. Zarumba and Granovsky also assert that "Net metering customers will increase the rates to non-participating customers. The reason for the increased rate pressure is that the level of compensation afforded these customers exceeds the costs which the balance of the customers are avoiding." (Exhibit 4.0, p. 34) That assertion is based on the Mr. Zarumba's marginal-cost study, which significantly understates marginal costs, as I explain in Section IV.

2. Intervenor positions

Intervenors (e.g., Riera Direct, pp. 8–9, Previdi Direct, pp. 1–8; V.L. Gonzalez Direct, pp. 3–7) discuss issues related to the net-metering arrangements. A number of intervenors identify the effect on net-metered customers of PREPA's proposals regarding CILT and subsidy charges, as these charges would not be reduced by the output from renewable generation behind the meter. They also point out that PREPA's proposed increases in customer charges would reduce the benefit of installing distributed renewable generation.

I agree with the intervenors that the net-metering credit should include the CILT charge and at least some of the subsidy charge, that the net-metering customers should not be charged for CILT and subsidies on the energy they supply to themselves, and that customer charges should not be increased as much as PREPA proposes.

While some intervenors complain about the treatment of the transition charge for new net-metering customers, that issue was settled in the restructuring proceeding and is not subject to review in this proceeding.

[126] In addition, the cost-of-service study has many other problems, as listed in Section II.

C. Structure of Net-Metering and Distributed-Generation Rates

1. PREPA proposal for net-metering credits

In the Restructuring Order (CEPR-AP-2016-0001, page 69, footnote 90), the Commission defined the following terminology "for the algebraically inclined," which will be helpful for sorting out the energy flows (in kWh) in this discussion:

G = behind-the-meter distributed generation
C = the customer's electric consumption
I = inflow from the PREPA delivery system through the customer's meter
O = outflow from the behind-the-meter generation to the PREPA delivery system
S = the customer's self-supply from the distributed generation
= C – I
= G – O
N = the customer's net consumption
= I – O
= C – G

C = S + I = G – O + I = N + G = N + S + O
G = S + O

In the Restructuring Order, the Commission decided that:

- Existing, grandfathered net-metering customers will pay the transition charge on their net consumption (N).
- New, non-grandfathered net-metering customers will pay the transition charge for their gross consumption (C), which equals net consumption (N) plus the customer's generation.

That decision is not under review in this proceeding, but the Commission faces similar choices regarding which other cost components should be included in the net-metering credit renewable generation.

As I read PREPA's filing, the only place in which PREPA proposed that the net metering compensation differ from the retail rate is that the H Schedules show the net-metering credit being computed as the sum of fuel, purchased-power and base energy rates, excluding the CILT and subsidy rates. As a result, I concluded that PREPA was proposing that the renewable net-metering customers pay the CILT and subsidy charges for their inflow (I) from the delivery system, but not be credited with those charges for exports to the system (O), with inflow and outflow computed on a monthly basis.

Some intervenors (Previdi Direct pp. 9–10; Feliciano Direct, pp. 8–14) interpreted PREPA's proposal as implying that the subsidy and CILT charges would be collected on the customer's total consumption (C), as the transition charge will be. In other words, they read PREPA's filing as proposing that energy from distributed generation would only reduce the customers' charge for the base rate, fuel rider and purchased-power rider, and not the transition, CILT and subsidy charges.[127]

In Schedule J, PREPA specified that the CILT and Subsidy costs would be divided over "Total Gross Retail Sales," in contrast to the "Total Net Retail Sales" used for the fuel and PPCA computations, where "Total Gross Retail Sales shall be the sales to all classes of classes including Net Metering Energy" and "Total Net Retail Sales shall be the sales to all classes of classes excluding Net Metering Energy," which leaves open the question of what "Net Metering Energy" means. In CEPR-PC-04-036, PREPA explained that the term "'Net Metering Energy' is the energy displaced by net metering customers by on-site generation."

In a conference call on October 31, 2016, Mr. Zarumba clarified that it was his intent that the CILT, subsidy and energy-efficiency charges be collected in the same manner as the transition charge, as the intervenors suspected. In retrospect, that also appears to be the intent of CEPR-PC-04-036.

Table 11 summarizes my current understanding of PREPA's proposals for the applicability of various rate components to net-metering customers.

Table 11: PREPA Proposed Application of Charges for New Net-Metering Customers

	Rate Determinant	Net Consumption	Outflow	Self-Supply
Base Energy Charge	N	✔		
Demand Charge		Maximum 15-minute load reduction		
Fuel Charge	N	✔		
Purchased-Power Charge	N	✔		
Transition Charge	C	✔	✔	✔
Subsidy Charge	C	✔	✔	✔
CILT Charge	C	✔	✔	✔
Energy-efficiency Charge	C	✔	✔	✔

PREPA would credit net-metering only for customers' reduction in net consumption times the base energy charge, fuel rider and purchased-power rider, plus any effect the distributed generation has on the customer's metered demand charge, for the primary and transmission rates.

[127] PREPA assumes that the CILT and subsidy charges would be in the form of reconciling riders. As I discuss in Section V, the manner in which those charges would be set remains to be determined.

2. Analysis of net-metering credits

The costs recovered by the riders do not warrant the exceptional ratemaking treatment afforded to the transition charge. The Commission took care to preclude bypass of the transition charge by new distributed generation. The CILT, subsidy and (if the Commission authorizes it) energy-efficiency riders, would recover components of PREPA's own revenue requirement. So long as PREPA has an adequate cushion for variation in revenues, avoiding bypass of these charges does not seem to be crucial. The extraordinary measure of preventing load reductions behind the meter from bypassing the transition charge is not warranted for any of the retail riders.

The CILT charge, in particular, recovers the equivalent of payments of local taxes, compensating the municipalities for PREPA's use of municipal services.[128] Taxes, or payments in lieu of taxes, are costs of doing business. I am not aware of any net-metering jurisdiction that excludes municipal taxes, income taxes, or franchise fees (which the CILT charge approximates) from the net-metering credit. The CILT charge is much like other PREPA fixed operating charges, which are reduced by the net-metering credit.

On the other hand, in jurisdictions with penetrations of solar much higher than Puerto Rico's, regulators frequently omit from the net-metering credit some charges that represent additional social commitments beyond the usual utility revenue requirements, such as energy-efficiency and low-income customer subsidies.[129]

Energy-efficiency program costs are very different from the costs of traditional utility functions, in that a distributed-generation customer can use energy-efficiency services regardless of how much energy the customer takes from PREPA. While the power that flows out from the distributed-generation customer to the delivery system can reduce PREPA's costs of generation, transmission and distribution, it does not affect the demand for energy-efficiency services. Nor is the energy from distributed generation likely to reduce the extent to which a net-metering customer can participate in the energy-efficiency program.

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[128]The usual rationale for payments in lieu of taxes (PILOTs) by a non-profit or governmental enterprise (e.g., a hospital, school, military base or utility) is to pay local government for the use of services supported by tax revenues, such as roads and public safety, which the enterprise uses. Alternatively, a PILOT may be used to compensate local government for the loss of property taxes and municipal license taxes that would have been paid if the property were privately owned (e.g., if PREPA were investor-owned). I understand CILT (and the provision of public street lighting at no cost) to roughly approximate the PILOT approach.

[129] Examples include California, Vermont and Massachusetts (which excludes only the statutory fees for energy-efficiency and support of renewables).

I recommend that the Commission limit the extent to which net-metering customers can avoid the energy-efficiency charge, by not crediting net monthly outflow with that charge.

The situation for the subsidy charge proposed in the PREPA filing is more complicated, since it comprises so many separate credits and discounts.

- The largest component of the subsidy charge ($93 million of PREPA's $174 million claimed subsidies) would be the costs associated with provision of free power to municipal public lighting, which used to be part of the CILT. As I discuss in Section 0., public lighting was included in CILT until recently, and has the same function of compensating the municipalities for PREPA's use of municipal services. As I noted above, tax payments by privately-owned utilities and payments in lieu of taxes by government utilities are normally treated as operating costs, rather than subsidies.
- A number of other items in PREPA's list of subsidies may be cost-justified (the GAS tariff, Analog rate, Condo Common Areas, totaling $7.1 million), and thus not subsidies.
- A third group of items in the subsidy charge are related to promoting economic and sales growth and increase, rather than decrease, PREPA revenues (the Hotels, Downtown Business, Economic Development, and Load Retention credits).[130] Hence, there is no cost to be collected for these item.
- A fourth group of items in the proposed subsidy charge is composed of items that are not designed as subsidies (the CEPR assessment and the direct-deposit discount, at $5.9 million).
- Excluding public lighting and the non-subsidy discounts leaves the four residential subsidies for low-income and other vulnerable residential customers (life-preserving equipment; the RFR tariff; the LICS discounts for the LRS and RH3 tariffs; and the fuel credit for LRS, RH3 and GRS 111) and the irrigation district subsidy, totaling $57.7 million. These items comprise about a third of PREPA's proposed subsidy charge for 2017.[131]

The Commission should limit the subsidy-charge component of the net-metering credit by excluding the portion of the charge corresponding to this last category: the residential

[130] PREPA projects that the Hotels discount will total $6.6 million in 2017. The Downtown credit is small and the other discounts do not yet exist and are not included in PREPA's subsidy forecast.

[131] Depending on the Commission's response to my recommendations in Section V, these may be the only values in the subsidy charge.

and irrigation-district subsidies. Table 12 summarizes my recommendations for the treatment of

Table 12: Recommended Interim Application of Charges for New Net-Metering Customers

	Rate Determinant	Net Consumption	Outflow	Self-Supply
Base Energy Charge	N	✔		
Demand Charge		Maximum 15-minute load reduction		
Fuel Charge	N	✔		
Purchased-Power Charge	N	✔		
Transition Charge	C	✔	✔	✔
Subsidy Charge	N+	✔	partial	
CILT Charge	N	✔		
Energy-efficiency Charge	I	✔	✔	

3. Limitation of net-metering eligibility

Messrs. Zarumba and Granovsky asserted that “LRS, RFR, and RH3 customer classes were excluded from Net Metering, as they are low income customers who are already being heavily subsidized.” (Exhibit 4.0, page 34, footnote 4). This position is ill-considered, for a number of reasons. First, there are already some net-metered LRS customers.[132] Second, to the extent that the distributed generation reduces purchases at the lower first-block rates on the LRS and RH3 customers (or the fixed pricing rate on RFR), PREPA’s revenue loss would be lower for those rates than for GRS customers; PREPA’s proposed price for the first 425 kWh on the LRS rate (including CILT) is 12.4¢/kWh, while the comparable rate for GRS customers is 15.3¢/kWh. Third, since a GRS customer may suffer a financial reversal and become a LRS customer, PREPA would penalize customers for requiring assistance.

When reminded that it has LRS customers on net-metering, PREPA clarified that “A small amount of net metering load currently exists for LRS customers. However, in the future customers served under subsidized low income tariffs will not be allowed to installed [sic] onsite generation and receive payments as ‘Net Metering’ customers. Existing LRS customers will be grandfathered and receive the full net metering payment. LRS customers who install new renewable generation will be compensated at avoided cost.” (CEPR-PC-4-32)

[132] When reminded of this fact, PREPA said that those customers would be grandfathered into net metering.

I see no reason to bar low-income customers from hosting renewable generation. In the case of RH3 and RFR customers, who are in public housing, the outflow energy might first be used to offset the common usage of the building, with the remainder credited to the residents.

4. Credits for non-renewable distributed-generation

For behind-the-meter non-renewable distributed generation, PREPA asks that it be allowed to credit non-renewable DER only for its estimate of long-term marginal costs, which Navigant estimates to be about 8¢ to 9¢/kWh (Exhibit 4.0 at 32). These estimates were based on fuel prices that have proven to be unrealistically low; it is not clear how PREPA would propose to update marginal costs to avoid this problem in the future. It is also not clear whether PREPA is proposing to pay that price for the customer’s excess power (allowing the customer to use the DER output to reduce its purchases from PREPA) or for the entire DER output (forcing the customer to purchase its entire consumption from PREPA).

The major type of generation to which this rate provision would apply is cogeneration, using the same fuels as PREPA’s plants, but operating at much higher efficiency. Such generation may be desirable for Puerto Rico, economically and environmentally, and should not be discouraged where it can be economic. These issues should be taken up in the proceeding in which net-metering arrangements for renewable generation are reviewed. In the meantime, if a customer applies to PREPA to export non-renewable distributed generation, PREPA should file an updated computation of marginal costs and seek Commission approval of a tariff or contract to incorporate that buy-back rate.

5. Design of rates for distributed generation

As noted in Table 11, net-metering customers would not receive any credit against the demand charge for any power flowing out to the system. The demand charge would be reduced only to the extent that the renewable generation operated in the 15-minute period in which the customer’s maximum load for the month occurs. If the renewable generation reduces the customer’s load in that 15-minute period, the next-highest 15-minute period would determine the demand charge. A number of intervenors (Feliciano Direct pp. 16–18; Previdi Direct, p. 18) mention that demand charges, and PREPA’s proposal to increase demand charges, reduce the incentives for installing distributed solar. That concern strengthens my comments in Section VII.C.2, regarding the unsuitability of demand charges as a major rate-design component.

PREPA offers very limited testimony concerning retail rate design for net-metered and distributed generation. The major such issue that PREPA raises concerns rate unbundling:

> DER customers require unbundled service because they are serving some of their needs with the DER. However, the price signal from the bundled tariff does not differentiate those products which are needed and unneeded, which triggers cross-studies which could negatively impact both participating and non-participating customers.….The costs of distribution and transmission systems are currently bundled with generation costs. Therefore, no mechanism exists to properly compensate the utility (and thus avoid cross-subsidies from other customers) for the costs incurred by these customers. (Exhibit 4.0, p. 31).[133]

As I describe in Section VII.B, PREPA has not been able to explain how unbundling would be helpful for DER or any other matters.

D. Net Metering Recommendations

I recommend that the Commission set the net-metering credit at the sum of:

- the customer's base rate energy charge,
- the fuel charge,
- the purchased-power charge,
- the CILT charge,
- the portion of the subsidy charge not related to the residential and irrigation-district subsidies,
- any other approved riders, except the energy-efficiency charge.

The treatment of the CILT, subsidy and energy-efficiency charges are a matter of judgment, and the Commission's decision may reasonably differ from my recommendation.

The net-metering credit should be applied to net energy deliveries to the system on a monthly basis.

As previously determined by the Commission, the transition charge would be assessed on the net-metering customer's total consumption.

The Commission should require that net metering remain open to all customers with renewable generation.

All aspects of net-metering compensation should be subject to review in the subsequent rate-design proceeding.

[133] This passage appears to refer to both net-metered renewables and other distributed generation.

For non-renewable distributed generation, allow sales of excess energy at the current estimate of long-term marginal cost. I discuss corrections to PREPA's estimates of marginal costs. Those corrected values should be used until better estimates can be developed (and the payment for energy delivered by non-renewable distributed generation) in the subsequent rate-design proceeding. The values should also be updated in annual GRAs.

IX. PREPA Performance

As described in the sections above, much of the crucial work that Navigant has done for PREPA in this proceeding has been below industry standards. It has caused consultants to incur extra costs to identify errors, get clarification, seek documentary support, and sometimes even to understand the basic outlines of a proposal. Problems include the errors in the average-and-excess computations and the analysis of peak loads. Navigant witnesses have also made claims in testimony and discovery responses that they have been unable to support (such as the claimed benefits of the unbundled rates, or the response that billing determinants were decreased to reflect the residential fuel subsidy CEPR-PC-07-26). The witnesses' have frequently been unable to identify potential solutions, in such issues as whether coincident peak contributions could be computed in the same manner as non-coincident peaks, or whether multiple monthly peaks could be used for allocating generation costs for a utility in which every month contributes to capacity requirements. They took inconsistent positions between the cost-of-service study and rate design (on such issues as seasonality), and sometimes provided misleading information (such as the suggestion that PREPA had actual monthly NCP data by tariff code).

With regard to cost allocation and rate design, PREPA, the Commission and the public interest have been poorly served by PREPA's consultants. PREPA should take steps to procure more competent assistance from Navigant or other firms, or bring more of this expertise in-house.

Certification

I certify that the information, facts, schedules, exhibits and analysis provided here constitute my report, and is true and correct to the best of my knowledge.

/s/ *Paul Chernick*

Paul L. Chernick

November 23, 2016