STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

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Matter 15-00262 - In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority & Service Provider, PSEG Long Island LLC.

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275 Veterans Memorial Highway
Smithtown, New York

June 23, 2015
10:15 a.m.

ADMINISTRATIVE JUDGES:

The Honorable DAVID R. VAN ORT

The Honorable MICHELLE L. PHILLIPS

A P P E A R A N C E S:

Kevin R. Brocks, LIPA
Howard J. Read, LIPA
S. Jay Goodman, Esq. City of New York
Robert M. Loughney, Esq.,City of New York
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Matthew Weissman, Esq.,PSEG LI
Robert Grassi, Esq., PSEG LI
Bruce Miller, Esq., PSEG LI
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Michael W. Zimmerman, Esq., Utility Intervention Unit
Erin P. Hogan, Director Utility Intervention Unit
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Chris Leimone, Esq., Nassau County Attorneys Office
Samantha Wilt, Natural Resources Defense Council Joseph Schroeder, Suffolk County Legislature Office

LAURAE COHEN
Reporter

JUDGE VAN ORT: Good morning. We are here on Matter number 15-00262. It is entitled In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority & Service Provider, PSEG Long Island LLC. I am David Van Ort. I am the Administrative Law Judge with the Department of Public Service. To my right is Administrative Law Judge, Ms. Michelle Phillips. We have been assigned to conduct these proceedings.

We're here today for an evidentiary hearing. We have a couple of days set up for this process, and we will get through it this week. Again, we are here pursuant to a notice that was issued on May 27th. We're going to go around the room and take appearances of the parties. I just want to ask if there is an individual here from New York Best? New York Best had filed requests for party status. I believe there were no objections to that. It was filed and we heard no objections. It was filed on June 8th but if the individual hasn't appeared, I don't think we need to address anything at this point in time.

Let's go around the room and take appearances. We will start with Mr. Brocks.

MR. BROCKS: Good morning, Your Honors. For the Long Island Power Authority, the firm of Read & Laniado by Kevin Brocks and Howard Read.

JUDGE VAN ORT: Thank you.

MR. GOODMAN: Good morning, Your Honors. For the City of

New York, I am Jay Goodman. On my left is Bob Loughney, and we are with the firm of Couch White.

MR. BJURLOF: Good morning, Your Honors. My name is Tom Bjurlof. I am appearing pro se.

MR. WEISSMAN: Good morning, Your Honors. I am Matt Weissman with PSEG Service Corporation. We represent PSEG Long Island. I am joined this morning by Mr. Robert Grossi of PSEG Long Island and by our outside counsel, Mr. Bruce Miller with Cullen & Dykman.

JUDGE VAN ORT: Thank you.

MR. MAZZA: Good morning, Your Honors. On behalf of the Department of Public Service, my name is Guy Mazza. With me to my right is John Favreau and Nicholas Forst.

JUDGE VAN ORT: Thank you. Do we have any other parties?

MR. CALICA: Yes. Good morning, Your Honors. On behalf of the Town of Brookhaven. I am Robert M. Calica from Rosenberg, Calica & Birney LLP. As Your Honors know, we have not scheduled submission of our witnesses for cross examination, but we will be filing a post-hearing brief on the schedule that Your Honors have established. Thank you.

JUDGE VAN ORT: Thank you. Are there any other parties in the room?

MR. ZIMMERMAN: On behalf of New York Department of State Utility Intervention Unit, I am Mike Zimmerman. To my right is Erin Hogan.

JUDGE VAN ORT: Thank you.

MR. RAGONETTI: On behalf of Nassau County, my name is David Ragonetti and Chris Leimone with the Nassau County Attorneys office.

MS. WILT: Good morning, on behalf of the Natural Resources Defense Council, Samantha Wilt.

JUDGE VAN ORT: Anyone else that has filed for party status that hasn't identified themselves?

MR. SCHROEDER: My name is Joe Schroeder. I am here on behalf of Suffolk County.

JUDGE VAN ORT: For the benefit of the rest of the individuals in this room, we had a discussion here this morning. Judge Phillips will go into that in a moment. I just want to point out to you that in the week prior to this and even before that the parties have been engaging in discussions with respect to the exhibits that would be offered into evidence as well as the witnesses for which there will be cross examination.

They have prepared a document that has an exhibit list. As we go through this process, you are going to see that it looks somewhat orderly because of the fact that the parties have been working ambitiously toward structuring an efficient hearing this morning. We thank the parties for doing that.

JUDGE PHILLIPS: I know that there are a lot of people who are not familiar with our processes. I did mention earlier before we went on the record, I was explaining why some of the counsel were here in front of us speaking with us. We were discussing procedural matters. One of the procedural matters that came up is a request that would be made by the Nassau County attorney, an application to cross one of the panels that they had not previously identified that they would have cross examination for. We were discussing the process that we would use to handle that.

What we resolved is that Nassau County I believe tomorrow will indicate the questions that they have. We will reserve an exhibit number, and I believe they are directed to PSEG. PSEG will answer those questions. That exhibit number that has been reserved will be used for the identification of those answers. That becomes part of what is called the record. Our record is going to consist of everything that has been filed in our document management system, all of the testimony and exhibits that we will be using here today in getting into the record. We will prepare something called a transcript that will have all of the testimony, all of the questions that are asked based on that testimony, the answers that are provided and the exhibits are separately maintained but still part of the record. They are numbered so that when the parties get to the point when they prepare briefs, it is very easy for them to identify the testimony using the pages and line numbers of the transcript and then to identify the exhibits using the numbers that we have assigned to the exhibits.

We currently have what are called pre-filed exhibits. Those you will find in the document management system that exists on the department's web page. Those have all been numbered, and we have a numbering list for that. Today during cross examination and during the proceedings that we have here parties may want to introduce other information often times that consist of answers to questions that they have asked other parties. Those will also be given a number so that when the parties prepare their briefs after this process they can easily identify that.

That was one of the discussions we had here at the table. The other discussion, procedural discussion, that we had was simply discussing do we want to have all of the cross examination take place first or would we have one party who will be adopting their testimony orally but there is no cross examination, basically the timing for that and how that would happen. We are, I believe, turning to those steps next. One of the parties, our pro se party Mr. Bjurlof, will adopt his testimony. That will be copied into the record as though orally given but there are no questions for him.

Then we will turn to the next panel that we have our schedule for. They will be sworn in and we will proceed thereon. At the end of today's proceedings, we plan to enter in certain amounts of testimony for which there were no questions, and we will be doing that by affidavit. That's pretty much the process that we lay forth, and that's what we were discussing here. I didn't want anyone to feel they were left out. That's what we were discussing.

Are there any questions about the process? Okay, thank you.

JUDGE VAN ORT: One of the things in our June 8th ruling on hearing procedures is we indicated to the parties that they are to bring CDs or DVDs which have the testimony as well as the parties that are going to be providing DVDs for exhibits the testimony goes to the hearing reporter for the testimony to be copied in the DVD containing the exhibits provided to us. We will ensure they are provided into the DMM system and accurately represent the exhibit numbers attached to them. If the parties haven't provided those to the reporter, you can do so in advance of panels coming up but we want to make sure it is all done before the end of the day today. If anybody has no questions at this point, we can take a moment to do that now.

I just gave an instruction to the reporter. If any of you provided exhibits to the reporter in addition, the reporter is not going to be including those as part of the transcript. That is an issue that we will be addressing with our document management system. We also had a brief discussion with the counsel for the NRDC with respect to an affidavit of an individual. Counsel just asked if we can bring that up from tomorrow's schedule to today. We will take that right after Mr.

Bjurlof and we will address that.

Why don't we begin the hearing process. Mr. Bjurlof, if you are here, there you are. If you can take a seat in one of the first four chairs on the other end. You are going to have to push the microphone and hold it down when you speak.

EXAMINATION BY

JUDGE VAN ORT:

JUDGE VAN ORT: Mr. Bjurlof, would you raise your right hand, please. Do you swear or affirm that the testimony you are about to give in this proceeding is the truth, the whole truth and nothing but the truth?

MR. BJURLOF: I do.

JUDGE VAN ORT: Thank you. Inasmuch as there is no one representing him, I will simply question him and put his testimony into the record if anyone has no objections?

MR. WEISSMAN: No objections.

JUDGE VAN ORT: Mr. Bjurlof, did you prepare a document for this proceeding entitled "The Prepared testimony of Thomas Bjurlof Pro Se" which consists of a title page and eleven pages of typed text?

MR. BJURLOF: Yes, I did.

JUDGE VAN ORT: Is it correct that you did not include any exhibits as part of your testimony?

MR. BJURLOF: That's correct.

JUDGE VAN ORT: If I were to ask you, which I am, the questions that you have in your testimony, are the statements that you have made in response to those questions true and accurate at this point in time as they were when you prepared this testimony?

MR. BJURLOF: Yes, they are.

JUDGE VAN ORT: Do you have any additions or corrections to that testimony?

MR. BJURLOF: No, I do not.

JUDGE VAN ORT: Thank you very much. There are no questions for this witness?

MR. WEISSMAN: No.

JUDGE VAN ORT: Thank you, Mr. Bjurlof. Reporter, note that his testimony is to be copied into the record as if orally given.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

MATTER NUMBER 15-00262

In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC.

Prepared testimony of

Thomas Bjurlof, pro se

Long Island May 13, 2015

Q. Please state your name and address.

A. My name is Thomas Bjurlof. I reside at 57 Rockledge Path in Port Jefferson New York.

Q. Mr. Bjurlof, do you represent any business with an interest in these proceedings?

A. I do not. I am a resident of Suffolk County and LIPA rate payer. I have an interest in the deployment of efficiency and distributed resources on Long Island in a manner that is beneficial and economical for rate payers.

Q. Do you have professional experience relevant to the subject matter of this proceeding?

A. Yes I do. I was the founder and general manager of a business consulting group that specialized in regulatory and technological change in networked industries, foremost in telecommunications and electricity in the United States and Europe.

Q. Have you previously testified in proceedings before the Department of Public Service?

A. Yes I have. I provided statements last year at the Utility 2.0 public statement hearings, Case 14-01299.

Q. Is the Utility 2.0 program included in the scope of this proceeding?

A. It is to an extent. On March 30, 2015 the Administrative Law Judges Michelle L. Phillips and David R. Van Ort ruled as follows:

"*The Utility 2.0 Long Range Plan, along with an RDM and mechanisms for recovering energy efficiency program costs, are proposed for the period 2016 through 2018,*[2] *the term of the rate plan being considered here. We therefore conclude that the scope of issues to be addressed in this rate matter should be expanded to include (1) the impact of Utility 2.0-related issues on capital expenditures, revenue requirement and the O&M budget and (2) the operation and design of (a) the cost recovery rider and true-up mechanism for energy efficiency programs and (b) the RDM.*"

My testimony will focus on the impact of Utility 2.0 T&D capital expenditures on the revenue requirement over the three year period covered by this case.

Q. Have PSEG Long Island and/or LIPA proposed a comprehensive methodology to account for these impacts?

A. To my knowledge they have not.

Q. What is Utility 2.0?

A. For the purpose of this testimony I will rely on recommendations provided in a letter ("the Letter") dated April 15, 2015 from Audrey Zibelman, Chief Executive Officer, Department of Public Service, to Ralph V. Suozzi, Chairman, Long Island Power Authority. I quote:

"*Please find herein the recommendations of the New York State Department of Public Service (DPS or Department) concerning PSEG Long Island, LLC's (PSEG LI) first annual Long Range Plan (Utility 2.0 Plan or Plan). The recommendations are provided pursuant to the LIPA Reform Act (LRA) and are consistent with the Amended and Restated Operating Service Agreement (OSA) between LIPA and PSEGLI.*"

" *… the Utility 2.0 Plan is intended to provide PSEG LI customers with tools to manage their energy usage and utility bills more efficiently and effectively, and improve system reliability and power quality.*[1] *In its Utility 2.0 Plan, PSEG LI points to the specific goals of reducing peak demand and improving the efficiency and resiliency of the electric grid. The Utility 2.0 Plan also identifies immediate reliability challenges on the Long Island electric grid that could be addressed through market animating programs and new technologies, rather than* *traditional infrastructure deployment."*

Q. Have specific Utility 2.0 projects been identified at this time?

A. Yes. The Letter identifies three such projects. These projects are characterized as addressing "*high-priority load pockets on the Long Island System in Montauk, Far Rockaway, and Glenwood with market based innovative solutions.*" PSEG LI identifies in their response to interrogatories five additional projects where RFIs have been issued.

Q. How will these projects be funded?

A. I quote from pages four and five of the Letter:

"*Development and administration of the solicitations can be funded from the 2015 LIPA approved budget.*[16] *Additional funding for actual deployment of solutions should be considered within the 2016-2018 rate case and the proposed capital budget. Funding for capital expenditures to address the load pockets would be repurposed in part to pay for the Utility 2.0 Plan alternatives. Results of the solicitation processes, the PSEG LI ongoing rate proceeding, and* *forthcoming Integrated Resource Plan will ultimately inform the details of these programs, including implementation and cost recovery methods."*

Q. What types of costs and/or savings are considered for these projects?

A. Project costs of innovative Utility 2.0 projects are intended to "*reduce or defer traditional T&D capital expenditures*". This formulation is somewhat ambiguous in that it does not explicitly make a distinction between short term project costs that should be recorded in the revenue requirement for a given year, and long term costs or cost avoidance over the period of deferral or avoidance. The Utility 2.0 program in addition to considering direct project costs introduces system-wide long-run costs and in doing so relies on the concept of opportunity cost of network utilization and comparison with alternative approaches for meeting system needs and requirements. The program discussion does not, to my knowledge, explicitly use the phrase 'opportunity cost'. Notwithstanding specific terminology, the concept of opportunity cost is an integral part of the foundation of Utility 2.0.

Q. What do you mean by "opportunity cost"?

A. System network externalities are central to electric transmission and distribution networks. It is not possible to transmit electricity between and entry and exit point without affecting network utilization in a multitude of nodes of the network. The consideration of externalities of this kind is part of determining the opportunity cost of a project.

Q. Is opportunity cost a novelty concept introduced by the Utility 2.0 program?

A. It is not. It is a mainstay of economics and it plays a critical role in network economics. It is a core concept for analyzing the economics of electric systems. Opportunity cost provides the ability to make choices between competing innovative projects and traditional T&D investment in terms of externalities associated with each project. It thereby gives an enhanced understanding of overall incurred costs. The determination of opportunity cost should be inherent in the process of developing the revenue requirement.

Q. Does the rate plan make a distinction between short and long-run costs/savings?

A. Yes, it does make such a distinction. Short-run cost and savings variances are in some cases subject to short-run rate adjustments, for example "revenue decoupling". Long-run incremental costs and savings are brought into focus by the Utility 2.0 program. It is unclear, from testimony, how long-term adjustments are pro-rated.

Q. Should long-run incremental savings be part of decision-relevant costing criteria for the Utility 2.0 program?

A. Long-run incremental savings are critical for determining the economic value of proposed projects, and should hence be considered together with opportunity cost, and project cost in the evaluation of competing Utility 2.0 projects.

Q. Are any other costs/savings considered in relation to the proposed Utility 2.0 programs?

A. Yes, the Letter mentions the objective of "*smoothing peak demand*". Smoothing or reducing peak demand is an important objective because the marginal cost of generating electricity increases as a function of load.

Q. Since power generation belongs to the Integrated Resource Plan (IRP), are savings of this kind not out of scope of this proceeding?

A. Any cost associated with power generation would be out of scope. T&D costs that affect the marginal cost of meeting load should however be considered within scope of the rate plan. When determining what projects are selected for implementation, all savings entailed by these projects should be part of determining their (present) economic value and are hence a decision-relevant consideration that determines the costs to be recorded in the revenue requirement.

Q. Should the considerations discussed in your testimony regarding project cost, opportunity cost, and long-run incremental savings be considered as exclusive to the Utility 2.0 program?

A. My testimony is within the context of the Utility 2.0 program. As the operator in a non-competitive (non-contestable) retail market for electricity LIPA and PSEGLI are responsible for the cost of electricity to end-users. LIPA and PSEGLI are hence under an obligation to consider the "rate impact" (sometimes referred to as "the principle of prudence") of all of its infrastructure decisions. The revenue requirement is one of the determinants of rate impact. To be able to fully discharge its responsibilities under Utility 2.0, and under LIPA's constituting legislation as a general matter, it would be reasonable to require LIPA and PSEGLI to incorporate the considerations of opportunity cost, long run incremental costs/savings, and long-run rate impact of capital T&D investment decisions, and to adjust the revenue requirement according to such considerations.

Q. Since Utility 2.0 is a new program and specific cost data are not yet available, is it not premature to consider the issues you bring up at this time? The letter by the DPS reads as follows regarding requests for proposals to be issued: "*The solicitations should not prescribe solutions or provide specifications that in effect predetermine solutions*." Should we not wait until interested parties have responded to solicitations?

A. Although it may, under some circumstances, make some sense to issue requests for information (RFI) without specifying how prospective proposals will be evaluated, issuing requests for proposal (RFP) before determining the evaluation criteria does not seem reasonable.

Q. How would the approach you propose promote desirable goals such as reliability, fuel diversity, and the use of renewable generation?

A. These can be considered to be network externalities and should be incorporated in decision-relevant costing in terms of opportunity cost.

Q. In response to interrogatories PSEG states the following: "*At this point, PSEG LI is responding to the Utility 2.0 questions in a general manner, given the fact that no specific projects were identified in the question.*" Are the suggestions in your testimony premature?

A. They are not. The rules of decision-relevant costing for the Utility 2.0 program are a pre-condition for specific projects under the program. PSEG LI claims, in its response to interrogatories, that they are evaluating Utility 2.0 type solutions. "*PSEG LI is evaluating Utility 2.0 solutions for certain traditional, utility-type projects*". Such evaluation can and should not be done until the rules for decision-relevant costing have been determined. Proceeding without doing so would be "to put the cart before the horse". Utility 2.0 is, as I understand the program, not intended as a utility R&D laboratory, but as a process for engaging and animating market forces for the introduction and deployment of new, innovative and competitive utility solutions.

Q. Does this conclude your testimony?

A. Yes, at this time.

JUDGE VAN ORT: Counsel for NRDC, why don't we take the affidavit.

MS. WILT: Do I stay here?

JUDGE VAN ORT: Why don't you come up here so you have a microphone. Counsel, just to note for the record, this affidavit is prepared by NRDC with respect to the testimony of Jackson Morris, correct?

MS. WILT: Correct.

JUDGE VAN ORT: The testimony consists of -- if you want to refer to your affidavit to give us an overview of what the testimony is. Pages and any exhibits would be fine.

MS. WILT: The direct testimony of Jackson Morris consists of fifteen pages and Exhibit JM-1 which is the resume of Jackson Morris as well as the rebuttal testimony of Jackson Morris on behalf of NRDC which is five pages including the title page.

JUDGE VAN ORT: Thank you. We are going to accept that affidavit into the record. We will identify it as exhibit number -- I think the next number is Exhibit 101. Am I correct on that, Mr. Forst? He is nodding his head.

MR. FORST: Yes, Your Honor.

JUDGE VAN ORT: Exhibit Number 101. Thank you.

MS. WILT: Thank you.

JUDGE VAN ORT: We will move onto the testimony of Mr. Falcone. That was the first one on the list, correct?

MR. BROCKS: Your Honor, that will be by affidavit. The first scheduled witness is the panel.

JUDGE VAN ORT: Do you wish to put the affidavit in now or do you wish to wait at the end?

MR. BROCKS: I think we will wait and do it all at once. Thank you.

JUDGE PHILLIPS: We were just discussing off line, and I will just make a statement to try to make it as easy as possible for the court reporter. The next testimony that should be copied into the record would be the original and rebuttal testimony of Mr. Morris. That would be followed by the testimony of Mr. Falcone. He also has original and rebuttal, correct?

MR. BROCKS: That's correct.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Matter No. 15-00262 In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC.

Direct Testimony of

Jackson Morris

On Behalf of

Natural Resources Defense Council

May 14, 2015

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TABLE OF EXHIBITS

I. Identification and Qualifications

Q. Please state your name and business address.

A. Jackson Morris, 40 West 20th Street, New York, NY 10011.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Natural Resources Defense Council ("NRDC").

Q. Mr. Morris, by whom are you employed and in what capacity?

A. I am Director of Eastern Energy at NRDC, which is a national non-profit environmental organization with more than 2 million members and online activists. Since 1970 our lawyers, scientists and other environmental specialists have been working to protect the world's natural resources and improve the quality of the human environment.

Q. Summarize your qualifications.

A. I joined NRDC in January 2014. Prior to joining NRDC, I was a Senior Policy Advisor at the Pace Energy and Climate Center. And before my position at Pace, I was the Air & Energy Program Director at Environmental Advocates of New York, where I worked on complex air quality and energy issues with several broad coalitions to effectively implement the Regional Greenhouse Gas Initiative, Energy Efficiency and Renewable Portfolio Standards, as well as a wide array of clean energy and efficiency projects in Albany.

I have a B.A. in Sociology and certificates in Primatology and Markets & Management from Duke University, as well as an M.S. in Environmental Policy from Bard Center for Environmental Policy. I have also taught environmental science at bilingual schools in the 18 Caribbean and studied sustainable development in Central America.

Since 2014 I have represented NRDC in regulatory utility matters, including proceedings before the Commission related to Reforming the Energy Vision, distributed and utility scale renewable energy, energy efficiency, and distributed generation. In addition I represent NRDC and other environmental parties as a voting member of the NYISO governance process. In the course of this work I have reviewed and provided input on various analyses related to system planning and policies to scale up energy efficiency and other demand side resources, as well as analyzing the costs and benefits of utility local transmission plans (LTPs) and the role for Non Transmission Alternatives (NTAs) to provide more cost-effective solutions to meet reliability requirements and provide safe and reliable service. Exhibit____JM-1 provides other details of my professional background.

II. Introduction

Q: What issues will you address in your testimony?

A: I will address PSEG-LI's energy efficiency and renewable energy deployment, as well as the need to improve the integration of its Utility 2.0 Plan programs and other related proceedings with its proposal in this matter.

III. Energy Efficiency

Q: Has New York State adopted a goal to reduce greenhouse gas emissions?

A: Yes. On August 6, 2009, Governor David Paterson issued Executive Order 24 (2009), which established a goal "to reduce current greenhouse gas emissions from all sources within the State eighty percent (80%) below levels emitted in the year nineteen hundred ninety (1990) by the year two-thousand fifty (2050)". This same Executive Order was subsequently renewed and reaffirmed by Governor Cuomo in 2011, soon after he took office.

Q: How can New York State achieve this goal?

A: New York State can achieve this greenhouse gas reduction goal by significantly ramping up the deployment of clean energy resources, and in particular through the effective adoption and implementation of strong, clear targets for both energy efficiency and renewable energy.

Q: What target should New York State adopt with respect to energy efficiency?

A: Based on best practices and proven program performance in other leading states, New York should adopt a *minimum* 2% annual savings rate for energy efficiency. As proposed in the recent Reforming the Energy Vision ("REV")

Track I Order, these investments should continue as an integral part of utility operations on an ongoing basis, without a sunset.

Q: What is an appropriate energy efficiency target for PSEG-LI?

A: PSEG-LI should procure all cost-effective energy efficiency and should similarly adopt a *minimum* 2% annual savings rate, in accordance with the recommended New York State energy efficiency goal, mentioned above. PSEG-LI should be responsible for determining how these savings would be achieved among the various programs in its service area, with input from stakeholders.

Q: **Has PSEG-LI proposed an energy efficiency target?**

A: No, it does not appear that PSEG-LI has adopted or proposed an explicit energy efficiency target.

Q: **Is PSEG-LI sufficiently focused on the development and implementation of baseline energy efficiency programs that will result in persistent energy savings?**

A: No. PSEG-LI proposed a number of projects in its Utility 2.0 Plan, which would be developed and implemented from 2015 – 2018, and that, according to PSEG-LI's testimony, are anticipated to result in 250 MW of savings. In its testimony, PSEG-LI states that "[t]he immediate focus of [these] proposed near term projects center on the programmatic and targeted use of distributed energy resources and other technologies that have the potential to enhance customer energy choices and achieve greater system efficiency, with an emphasis on reducing peak demands and improving system load factor and asset utilization." Direct Pre-filed Testimony of the Utility 2.0 and Energy Efficiency Panel at 7. While I agree that improving system efficiency is an important consideration from a cost and emissions perspective, particularly on Long Island with its unique locational capacity requirements, PSEG-LI should pursue a more balanced approach that avoids an overemphasis on peak reduction (MW) to the detriment of overall demand (MWh) reduction. For example, if the "tails" of Long Island's load curve are raised to a greater degree than the peak is lowered, it would result in an improved system efficiency percentage, but (based on the current power supply portfolio) also increased emissions and greater overall electric demand. While NRDC fully recognizes and supports the need to reduce peak demand due to the environmental and consumer benefits those investments deliver, a more balanced demand side portfolio is essential. PSEG-LI should avoid focusing too heavily on programs targeting MW peak demand reductions if doing so results in reduced investments in energy efficiency programs that would otherwise achieve a 2% annual MWh energy savings target.

Q: Should PSEG-LI also adopt a target specifically focused on scaling up energy efficiency in affordable multifamily housing?

A: Yes. Within an overall minimum 2% annual target for energy efficiency, PSEG-LI should aim for sustained electric savings of 1.5% per year in its multifamily buildings. This target is consistent with Optimal Energy's findings included in its October 2014 analysis of "New York State Multifamily Efficiency

Opportunities" prepared for the Energy Efficiency for All coalition ("Coalition") and submitted as Exhibit A in the Coalition's October 2014 reply comments in the REV docket.[1] Within this sector, there should be a particular focus on affordable multifamily housing, for which there is significant potential in PSEG-LI's service territory (55 GWh through 2034), as Optimal's May 2015 report entitled, "Potential for Energy Savings in Affordable Multifamily Housing" demonstrates.[2]

IV. Renewable Energy

Q: What target should New York State adopt with respect to renewable energy?

A: Building on the state's successful renewable energy programs to date, such as NY-Sun, LIPA's Solar Pioneer and Clean Solar Initiative Feed In Tariff solicitations, as well as the state's broader existing Renewable Portfolio Standard, New York should adopt a renewable energy goal of 50% by 2025. Doing so will send a clear signal to the market that the State is committed to the continued deployment of these valuable resources, and reassert the state's position as a national leader on renewable energy.

[1] *See* http://www.optenergy.com/wp-content/uploads/2014/08/New-York-State-MF-Efficiency-Opportunities.pdf at 10.

[2] *See* http://www.energyefficiencyforall.org/sites/default/files/EEFA%20Potential%20Study.pdf at 19.

Q: **Should PSEG-LI contribute to this 50 x '25 state renewable goal?**

A: Yes. In keeping with a statewide goal of 50% by '25, PSEG-LI should also ensure that 50% of its electric demand is supplied by renewable resources by 2025.

Q: What renewable resource potential does Long Island have to help the state achieve a 50 x '25 renewable energy goal?

A: Long Island has extensive renewable resource potential, including substantial untapped offshore wind and solar power. A 2012 analysis completed by Synapse Energy Economics, Inc., entitled, "A Clean Electricity Vision for Long Island", estimated that 75% of Long Island's electricity demand could come from renewable resources by 2030.[3] In addition, the New York State Energy Research and Development Authority (NYSERDA) BOEM Offshore Wind Cost-Benefit Study modeled a "probable scenario" of 2,450 MW of offshore wind in the New York Bight by 2025, and an "optimistic scenario" of 3,450 MW.[4] In its November 2014 study, "Offshore Wind Energy and Potential Economic Impacts in Long Island", the New York Energy Policy Institute of Stonybrook University also concluded that their "review of the literature, BOEM's leasing and state policies related to offshore wind suggest that Long Island's near term addressable market for offshore wind development is

[3] *See* http://www.synapse-energy.com/sites/default/files/SynapseReport.2012-08.RELI_.Long-Island-Clean-Energy-Vision.11-054.pdf at 7.

[4] *See* http://www.boem.gov/NYSERDA-Offshore-Wind-Program-Update/ at 3.

approximately 8,850 MW, of which 2,500 MW is in federal waters abutting New York State."[5] And while existing programs have driven significant deployment of solar, there remains substantial potential to expand the percentage of power provided by solar PV even further in the coming decade and beyond. PSEG-LI should ensure their distribution system investments (in this rate proposal as well as subsequent planning exercises) are made with an eye towards a future that includes significant increases in renewable energy penetration at both the utility scale and distributed levels.

Q: If Long Island were subject to a new "50 x 2025" renewable energy requirement, would all of those resources need to be "on island"?

A: No. Just as customers in Southeast New York are contributing to expand wind Upstate in order to deliver the economic, environmental, and fuel diversity benefits those projects provide to all New Yorkers, PSEG-LI customers can be part of the overall statewide effort to reach the 50 x '25 target even if some of the projects built are off island.

Q: In addition to mitigating greenhouse gas emissions through the increased deployment of energy efficiency and renewable energy resources, should PSEG-LI also address the impacts of climate change in its planning?

A: Yes. Given the need for PSEG-LI to ensure the reliable provision of service to its customers and that climate change will alter the environmental conditions in

[5] *See* http://www.aertc.org/docs/SBU%20OSW%20Eco%20Dev%20Final%2011-25.pdf at 15.

which PSEG-LI's system will need to operate, PSEG-LI should perform short- and long-term vulnerability assessments regarding climate change; conduct an analysis of alternatives to improve resiliency; and, prepare a long-term climate adaptation plan, which should be updated on a regular basis. The Public Service Commission explicitly stated the need for all utilities to address climate change considerations in its February 2014 Order approving Con Edison's electric, gas and steam rate plans.[6]

V. Improving Integration of Utility 2.0 Plan Programs and Other Related Proceedings

Q: What other planning processes are underway or anticipated that impact PSEG-LI's system buildout?

[6] "The State's utilities should familiarize themselves with scientists' projections for local climate change impacts on each service territory. These will differ: other coastal and estuarine utilities also face sea level rise and storm surges, while all the State's utilities face challenges such as Hurricane Irene and Tropical Storm Lee, Nor'easters, floods, severe winds, increasing ambient heat, and extreme heat events. We expect the utilities to consult the most current data to evaluate the climate impacts anticipated in their regions over the next years and decades, and to integrate these considerations into their system planning and construction forecasts and budgets." New York State Public Service Commission Case No. 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service et al., Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal (issued February 21, 2014), at 71-72.

A: Currently PSEG-LI is undertaking the development of an Integrated Resource Plan (IRP) which: "forecasts future load and energy use, identifies supply and demand side resource options to meet the load, and evaluates alternative resource portfolios that could deliver reliable energy to customers at reasonable costs, considering, among other factors, environmental impacts, supply diversity and system resiliency. The IRP will also identify needs to be addressed through future resource procurements." The IRP will take up to 18 months to complete, and is anticipated to be concluded during the first quarter of 2016.

The REV proceeding is also currently underway (Public Service Commission Case No. 14-M-0101). The six objectives of this proceeding are: "1) Enhanced customer knowledge and tools that will support effective management of the total energy bill; 2) Market animation and leverage of customer contributions; 3) System wide efficiency; 4) Fuel and resource diversity; 5) System reliability and resiliency; and 6) Reduction of carbon emissions." PSEG-LI is a party to the REV proceeding and states that it "intends to continue to be mindful of the policies and initiatives being developed in that proceeding and to incorporate them in future Utility 2.0 Plan annual filings." Direct Pre-filed Testimony of the Utility 2.0 and Energy Efficiency Panel at 4. The REV Track One Order was issued on February 26, 2015, and the REV Track Two Straw Proposal is due July 1, 2015. The anticipated REV Track II order is expected to fundamentally change the valuation of capital investments for utilities so that they are pursuing clean energy resources like renewable energy and energy efficiency with the same vigor that they currently invest in traditional "poles and wires" infrastructure. The REV Track II order will also determine what changes are necessary to improve and enhance the ways consumers receive and use electricity, and how utilities maintain and build out their systems. These changes could profoundly impact utility investments and resource and supply decisions, and consequently the underlying assumptions this rate case is based on.

And finally, the current Utility 2.0 process has the next filing due in December 2015 (pushed back from July 2015), that will assumedly incorporate projects consistent with the REV principles, while investments that were recommended by the Department of Public Service (DPS) in response to PSEG-LI's 2014 Utility 2.0 filings in April 2015 do not appear to have been incorporated into PSEG-LI's proposal in this matter.[7] As a result of all of these concurrent processes, we anticipate significant changes to—and likely expansions of—the PSEG-LI energy efficiency, renewable energy, and

[7] DPS Staff stated at the March 3, 2015 Technical Conference that they believed the T & D Deferral projects should be addressed in this matter. "MR. GARVEY: Just to reiterate DPS Staff's position, is that we believe the three projects on the first row, in addition to AMI deployment generally, should be addressed in this rate case." Technical Conference Transcript at 136.

other demand side management programs that will have an impact on the build out of the utility's system in 2016-2018.

Q: Has PSEG-LI included in its proposal in this matter the projects recommended for immediate implementation in the Department of Public Service's April 15, 2015 recommendations concerning PSEG-LI's Utility 2.0 Plan?

A: No. It has not included the expanded Direct Load Control Program or T & D Deferral programs.

Q: What are the impacts of not including these projects?

A: By not including the expanded Direct Load Control program, totaling 125 MW of capacity, of which 90 MW is new (Exhibit UEE_1), PSEG-LI likely overstates its peak load capacity requirement, and consequently may be proposing system investments that are either unnecessary or not appropriately sized for the system needs.

The planned Transmission and Distribution Deferral projects for Montauk, Glenwood and Far Rockaway will also reduce and smooth peak demand and should reduce capital costs for peak capacity, by definition, since the solicitations will fulfill requirements under the PSEG-LI Operating Services Agreement to:

(b) incorporate, where cost effective, programs to reduce or defer significant capital expenditures associated with the traditional T&D System and smooth peak demand,

including programs related to energy efficiency, demand response, distributed generation, energy storage, micro-grid systems and vehicle recharging;[8]

These planned investments should be fully accounted for as PSEG-LI plans and builds out its system in this rate case.

Q: Does NRDC support these T&D deferral projects?

A: Yes. NRDC has long been an advocate for energy efficiency and clean distributed resources as alternatives to due to their multiple environmental, economic and customer savings benefits (often referred to as the win-win-win solution). Furthermore, NRDC's Energy Efficiency For All project has been working in a number of states (including New York) to increase energy efficiency investments in affordable multifamily housing. And we have long advocated *against* meeting the increasing load demands in the South Fork with additional dirty, expensive diesel powered peaker plants. For all these reasons we strongly support the anticipated T&D deferral projects in Montauk, Far Rockaway and Glenwood. Further, we urge an emphasis on providing efficiency services for low and middle income residents in Far Rockaway as detailed in the July 1, 2014 Utility 2.0 filing.

Q: Does this complete your testimony?

A: Yes.

[8] PSEG-LI Operating Services Agreement, Section 4.2(a)(5), quoted in Utility 2.0 and Energy Efficiency Panel Testimony, p. 5.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Matter No. 15-00262	In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC.

Rebuttal Testimony of

Jackson Morris

On Behalf of

Natural Resources Defense Council

June 4, 2015

I. Identification and Qualifications

Q. Please state your name and business address.

A. My name is Jackson Morris. I am Director of Eastern Energy at the Natural Resources Defense Council ("NRDC") for which my business address is 40 West 20th Street, New York, NY 10011.

Q: Did you prepare direct testimony in this case that was filed on behalf of NRDC on May 14, 2015?

A: Yes, I did.

Q: On whose behalf are you submitting this rebuttal testimony?

A: I am submitting this testimony on behalf of the NRDC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to certain intervenor testimony provided in this matter. Specifically, I respond to testimony filed by the Department of Public Service (DPS) Staff Rates Panel regarding customer charges. In addition, I support testimony filed by witnesses Marczewski and Horton for the City of New York regarding holistic storm hardening and full integration of climate change impacts and resilience measures in planning.

Q. Do you have a response to DPS Staff Rates Panel testimony regarding customer charges in this matter?

A. Yes. DPS Staff Rates Panel testimony addresses customer charges:

> *Residential and Small Commercial Customer charges - PSEG LI's proposed increases result in substantial rate impacts on low use customers. Therefore, we*

recommend rejecting PSEG LI's proposal and addressing this issue for these service classifications consistent with the outcome of the REV Track 2 proceeding.

(Direct Test. of Staff Rates Panel at 10:14-21) (*See also* Direct Test. of Staff Rates Panel at 14:1-17 and 16:16-22; 17:1-8). We strongly agree with Staff's testimony that substantial customer charge increases are a concern, and are contrary to the rate design principle of gradualism, by causing rate shock. We also concur with Staff's testimony that the large customer charge increases will disproportionately impact low use customers, and those customers are often low- and fixed-income customers who are least able to bear these increases. This is a regressive change to rate design that we strongly oppose.

Q. Do you have other concerns about large increases to customer charges?

A. Yes. Large increases to customer charges erode the economics of investment in energy efficiency and clean distributed generation, will penalize customers' past investments in energy efficiency and clean distributed energy, and reduce future investments in these resources by reducing the energy cost savings that result from their investments. The economic payback period for customers' past efficiency and clean distributed generation investments will be lengthened by higher customer charges, depriving these customers of their fair and reasonable expectations of returns from those investments they have already undertaken. And future investments by customers are also impacted with these longer payback periods, making new investment in efficiency and clean distributed generation less likely, since a portion of the savings streams are taken by the new higher fixed charges.

Q. Are there additional resources that address the market distortion resulting from high customer charges?

A. Yes. The Regulatory Assistance Project ("RAP") has completed a number of papers addressing high customer charges and their potential to undermine policy objectives, including *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs* (attached as Exhibit _A). In this paper, RAP specifically argues that high customer charges negatively impact small-use, including low-income, customers and urban area residents that use gas for heating:

> [T]he impacts on customers of high customer charges can be inconsistent with policy objectives:
>
> - Small-use customers, such as apartment dwellers, low-income households, and second homes will receive much higher electric bills; the vast majority of low-income consumers are also low-use consumers. This is anathema to public policy objectives that normally tend to protect low-income customers and/ or reward low usage;
> - Urban area residents who use natural gas for space and water heat will receive much higher electric bills;[1]

Also attached as Exhibit_B is a paper titled *Economic concerns about high fixed charge pricing for electric service,* by Steve Kihm, detailing the economic arguments against high customer charges:

> High fixed charge pricing negatively impacts low users, many of whom are low-income customers. Under this approach the bill for those using less than the

[1] Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs, Jim Lazar, November 2014 at http://www.raponline.org/document/download/id/7361.

> average amount of power is higher than the bill they receive under traditional pricing. But since the fixed fee represents the bulk of the monthly bill, and that fee doesn't change with usage, customers can't do much to lower their bill.

And, in summation: "High fixed charge pricing steers the economy away from efficient resource allocation, not toward it."[2]

Q. Is there additional direct testimony you support?

A. Yes. I support the testimony of John Marczewski and Radley Horton on behalf of the City of New York addressing holistic storm hardening and full integration of climate change impacts and resilience measures in planning. We also support a broad collaborative effort to address these issues, modeled on the robust Con Edison process as part of Case 13-E-0030 as suggested in Prepared Direct Testimony of John Marczewski (*See* Direct Test. of Marczewski at 12:20-23; 13:1-16).

Q: Does this conclude your testimony?

A: Yes.

[2] Economic concerns about high fixed charge pricing for electric service. Steve Kihm, October 2014 at http://americaspowerplan.com/wp-content/uploads/2014/10/Economic-analysis-of-high-fixed-charges.pdf

JUDGE VAN ORT: The next panel we have is the LIPA Overview Panel which consists of Mr. Falcone, Kane and Shansky, I believe.

MR. BROCKS: That's correct, Your Honor.

EXAMINATION BY

MR. BROCKS:

JUDGE VAN ORT: Gentlemen, would you raise your right hand, please. Do you swear or affirm that the testimony you are about to give in this proceeding is the truth, the whole truth and nothing but the truth?

MR. FALCONE: I do.

MR. KANE: I do.

MR. SHANSKY: I do.

JUDGE VAN ORT: Mr. Brocks, your witnesses.

MR. BROCKS: Thank you, Your Honor.

Gentlemen, can you hear me?

MR. FALCONE: Yes.

MR. BROCKS: Panel, do you have before you a twelve-page document entitled "Direct Testimony of Overview Panel, Long Island Power Authority"?

MR. FALCONE: Yes.

MR. BROCKS: Do you have any changes or corrections you wish to make to that pre-filed testimony?

MR. FALCONE: No, we do not.

MR. BROCKS: If I were to ask you the questions as they are set forth in that pre-filed testimony, would your answers be the same here today?

MR. FALCONE: Yes.

MR. BROCKS: Do you wish to adopt this document as your sworn testimony in this proceeding?

MR. FALCONE: We do.

MR. BROCKS: Panel, did you also prepare exhibits?

MR. FALCONE: Yes.

MR. BROCKS: That consists of two pages and, Your Honor, it was marked as Exhibit Number 2.

Do you wish to sponsor that exhibit in this proceeding?

MR. FALCONE: We do.

MR. BROCKS: Your Honor, may we have the testimony of the panel placed in the record as though given orally here today?

JUDGE VAN ORT: Any objections?

MR. WEISSMAN: No, Your Honor.

JUDGE VAN ORT: The testimony will be copied into the record as if orally given.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan

Matter Number: 15-_____

DIRECT TESTIMONY OF

OVERVIEW PANEL

LONG ISLAND POWER AUTHORITY

JANUARY 30, 2015

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Thomas Falcone, Chief Financial Officer, Long Island Power Authority (the “Authority”), 333 Earle Ovington Boulevard, Suite 403, Uniondale, New York 11553.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science in Economics from the University of Pennsylvania Wharton School. Professionally, I spent 13 years in investment banking working in municipal and utility finance. In that capacity, I raised approximately $30 billion of capital for many of the largest public power utilities and municipal borrowers in the country. I joined the Authority in January 2014.

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Rick Shansky, Managing Director of Contract Oversight, Long Island Power Authority (“Authority”), 333 Earle Ovington Boulevard, Suite 403, Uniondale, New York 11553.

Q. WHAT ARE YOUR RESPONSIBILITIES AT THE AUTHORITY?

A. I direct the Authority's oversight of its primary contractor PSEG Long Island ("PSEG-LI"), as well as its affiliate that performs day-to-day power and fuel procurement. I am also responsible for managing the Authority's participation in wholesale power markets.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science in Electrical Engineering from Rensselaer Polytechnic Institute and a Master of Science in Energy Management from NY Institute of Technology. I am licensed as a Professional Engineer in the State of New York. I have more than 30 years of experience in the electric utility industry, and previously held positions at Consolidated Edison Company of New York ("Con Edison") and the Long Island Lighting Company ("LILCO") in the areas of energy management, resource planning, fuel and purchased power, and generation planning. I joined the Authority in 2008 and held management positions in the Power Markets department before assuming my current position in September 2014.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN RATE PROCEEDINGS IN NEW YORK STATE?

A. Yes. I testified as a witness for Con Edison in Public Service Commission ("PSC") Cases 07-S-1315, 05-S-1376, 03-S-1672, 99-S-1621, and 94-E-0334.

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Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Kenneth Kane, CPA, Managing Director of Finance and Budgeting, Long Island Power Authority, 333 Earle Ovington Boulevard, Suite 403, Uniondale, New York 11553.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a BA from Pace University and a MBA in Finance from Hofstra University. I worked in public accounting beginning in 1984 and joined the Long Island Lighting Company ("LILCO") as an accountant in 1988. I joined the Authority in 1999 and served as Director of Financial Reporting until 2001 when I was named Controller. I was appointed Managing Director of Finance and Budgeting in late 2013. I am responsible for the finance and budgeting operations, as well as our efforts to obtain and administer various grants, including those associated with storm recovery and hardening.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The Authority Overview Panel's testimony will explain three overarching topics related to the Rate Plan: the organizational structure of the Authority; the Authority's contractual and financial relationship with PSEG-LI, the service provider under the Amended and Restated Operations Services Agreement ("OSA"); and the process for setting the Authority's rates.

Q. HOW IS THE AUTHORITY DIFFERENT FROM OTHER UTILITIES?

A. The Authority was created by New York State legislation in 1986. The Authority is a political subdivision of the State of New York that is governed by a Board of Trustees appointed by the Governor, the Majority Leader of the State Senate, and the Speaker of the State Assembly. Our senior officers are appointed by the Board of Trustees.

The Authority is a not-for-profit utility operated for the benefit of our customers. We obtain money from two places—customers and lenders. We have no shareholders. We are also eligible for federal and state grants in the event of a severe storm or to fund certain energy efficiency programs. The Authority does not pay dividends. We serve 1.1 million customers and a population of over 3 million in Nassau and Suffolk Counties and the Rockaways in Queens County.

Q. WHAT IS THE AUTHORITY'S ORGANIZATIONAL STRUCTURE?

A. The Authority is managed by a staff of 40 employees organized into three areas—finance, legal, and contract oversight. The Authority owns the electric system but contracts out day-to-day operations.

From 1998 to the end of 2013, a subsidiary of KeySpan (owned by National Grid since 2007) was the operator of the electric system under a Management Services Agreement ("MSA"). After a competitive procurement process, the new operator—PSEG-LI—was chosen in December 2011. Subsequently, in 2013, the LIPA Reform Act imposed greater operational and policymaking responsibilities on PSEG-LI. These expanded responsibilities were reflected in the Amended and Restated OSA ("OSA"). PSEG-LI began operating the system on January 1, 2014 pursuant to the OSA. Also, as a result of the LIPA Reform Act, the Authority reduced its staff from approximately 100 to 40, which is the minimum necessary to allow the Authority to meet its debt obligations, manage its contractual and legal obligations, and to oversee the performance of PSEG-LI.

Under the OSA, PSEG-LI is now the brand for electric service in the Authority's service area, and PSEG-LI is responsible for all operations of the transmission and distribution system, customer service and customer satisfaction activities, and communications with the media and the public. PSEG-LI and its affiliate assumed responsibility for power supply planning and procurement in January 2015, giving PSEG-LI functional control over the total operations of the utility that provides electric service to the Authority's Long Island service territory.

Q. HOW DOES THE OSA GOVERN THE FINANCIAL ARRANGEMENTS OF LIPA AND PSEG-LI?

A. LIPA owns the electric system and pays PSEG-LI for its costs plus a management fee to operate it. Although PSEG-LI handles most of the individual transactions with customers and suppliers, PSEG-LI does not gain or lose financially from the revenues it collects on behalf of LIPA, nor does it profit directly from any variations in the costs paid to run the system, including the cost for purchasing fuel and power in the various commodity markets.

On the other hand, the management fee paid PSEG-LI includes incentives for meeting operational and customer satisfaction goals. Financially, the threshold requirement to earn incentive compensation under the OSA is for PSEG-LI to operate the system within 102% of its approved operating and capital budgets. The OSA provides PSEG-LI with substantial flexibility to reallocate or postpone approved operating and capital expenditures so that financial incentives do not interfere with proper operation of the electric system.

Q. ARE THERE ANY EXCEPTIONS TO THE 102% OF BUDGET CAP FOR PSEG-LI TO EARN INCENTIVE COMPENSATION?

A. Yes, certain expenses that are managed by PSEG-LI are not subject to the 102% limitation, such as fuel and purchased power costs, given the limited ability of PSEG-LI to control these costs, which are largely determined by the marketplace. Such expenditures are characterized as PSEG-managed costs within the Authority's budgets and revenue requirements. In addition, the OSA recognized that even for areas that fall within the PSEG-LI Operating and Capital Budgets, there are some types of events that are beyond the reasonable control of the Service Provider. These "Non-Storm Emergency Events" may require expenditures to provide unanticipated Operations Services, such as to repair or replace damaged components of the T&D System. One such example that occurred in 2014 was the incremental expenses associated with a transmission cable failure. When such events occur, PSEG-LI has the right to request a budget amendment for such costs. Whether or not the Board approves a budget amendment for the purpose of measuring incentive compensation, these expenses are paid for by the Authority, provided they are reasonable and necessary.

Q. ARE THERE ANY OTHER SIGNIFICANT EXCEPTIONS TO THE BUDGET CAP THAT ARE RELEVANT TO THE RATE PLAN?

A. Yes, in this three-year Rate Plan, expenditures for Utility 2.0 and their associated impacts on energy sales, revenues, and expenses have been omitted. Utility 2.0, and the associated *Reforming the Energy Vision* ("REV") initiative, are the subject of separate proceedings that are on a separate track from the three-year rate plan. Both the Authority and PSEG-LI have been actively engaged with the Department of Public Service to develop, review, and recommend projects and programs that will reduce energy consumption beyond that achieved through existing energy efficiency programs, and to further reduce reliance on traditional utility solutions such as generation from fossil fueled central generating stations and the construction of relatively expensive transmission and distribution assets. The Authority and PSEG-LI are ready to develop and deploy innovative solutions that are recommended by the Department of Public Service and approved by the Trustees. Such approvals would include an appropriate revision to the budgets in a manner that does not penalize PSEG-LI for pursuing these worthwhile expenditures, consistent with the approach taken to the approved 2015 operating and capital budgets. Further, since the nature, timing, and scope of such recommendations cannot be known at this point, the Authority and PSEG-LI have developed a rate plan that establishes rates and revenue requirements at their pre-REV levels, and looks forward to recommendations from the Department that address all the components of revenue impacts and cost recovery associated with the Utility 2.0 programs.

Q. WHAT IS THE AUTHORITY'S RATEMAKING PROCESS?

A. The Board of Trustees is responsible for all aspects of the Authority, including setting rates. For this particular proceeding, the LIPA Reform Act requires PSEG-LI and the Authority to develop a "three-year rate plan." That plan is to be filed with DPS by February 1, 2015, with new rates to be effective January 1, 2016. DPS is obligated under the LIPA Reform Act to provide for public statement and evidentiary hearings, and provide a recommendation to the Board by September 30, 2015. If the Board of Trustees accepts the DPS recommendations, the plan and resulting rates are adopted. If the Board finds that a recommendation is "inconsistent with the Authority's sound fiscal and operating practice, any existing contractual or operating obligation or the provision of safe and adequate services…," then the Board would follow a process of public hearings to adopt a different rate plan than was recommended by DPS.

Q. WHAT OTHER STANDARDS HAVE BEEN ESTABLISHED FOR THE ROLE OF THE DEPARTMENT OF PUBLIC SERVICE WITH REGARD TO THIS PROCEEDING?

A. Under the general powers granted to the Department through the LIPA Reform Act,[1] the Department is empowered and authorized to review and make recommendations to the Board of Trustees with respect to rates and charges, including charges related to energy efficiency and renewable energy programs. The purpose of the DPS review is to make recommendations designed to ensure that the Authority and PSEG-LI provide safe and adequate transmission and distribution service at rates set at the lowest level consistent with sound fiscal operating practices. The Department's recommendations are to be designed to be consistent with ensuring that the revenue requirements related to such rate review are sufficient to satisfy the Authority's obligations with respect to its bonds, notes, and all other contracts. In the context of such

[1] See LIPA Reform Act, Part A, §3-b, paragraph 3.

review, the Department may not make any recommendation that would modify the compensation or fee structure included within the OSA.

Q. DOES THE RATE PLAN PRESENTED BY PSEG-LI AND THE AUTHORITY MEET THE CRITERIA FOR REVIEW BY THE DEPARTMENT OF PUBLIC SERVICE?

A. Yes. The three-year rate plan is designed to provide safe and adequate service at the lowest level consistent with sound fiscal operating practices, and satisfy the Authority's obligations with respect to its bonds, notes and all other contracts.

Q. HAS THERE BEEN A MANAGEMENT AUDIT OF LIPA AND ITS SERVICE PROVIDER?

A. Yes. NorthStar Consulting Group conducted a management and operations audit of LIPA and its service provider (then National Grid) and issued an audit report dated September 13, 2013. PSEG-LI became the service provider on January 1, 2014. While the audit focused on historic operations conducted by National Grid and the Authority, 40 of the 83 recommendations were to be addressed by PSEG-LI. The Authority tracks the status of both the Authority's and PSEG-LI's actions in response to the recommendations. As of year-end

2014, 35 of 43 Authority actions had been completed and 22 of 40 PSEG-LI actions had been completed. Exhibit __ (OP-1) shows the status of the Authority's 8 remaining actions, all of which are scheduled to be completed in 2015. PSEG-LI has reported to the Authority that its remaining actions are also scheduled to be completed in 2015, except for storm hardening actions which are expected to occur over a four year period in accordance with the FEMA funding agreement.

Q. DOES THIS COMPLETE YOUR PRE-FILED DIRECT TESTIMONY AT THIS TIME?

A. Yes.

JUDGE VAN ORT: We had this set up that there was only one party who indicated previously there would be cross examination which was the City of New York City. Is there still cross examination for this panel?

MR. GOODMAN: Yes, Your Honor.

JUDGE VAN ORT: Please proceed.

CROSS EXAMINATION BY
MR. GOODMAN:

MR. GOODMAN: Good morning, Gentlemen. My name is Jay Goodman. I am counsel for the City of New York.

MR. FALCONE: Good morning.

MR. GOODMAN: Counsel, initially, am I correct that LIPA and PSEG serve approximately 1.1 million customers; is that correct?

MR. FALCONE: Correct.

MR. GOODMAN: One customer is not necessarily one person, right? A customer could be a building with multiple residents or businesses, correct?

MR. FALCONE: Correct.

MR. GOODMAN: On a population basis, am I correct you serve approximately 3 million people?

MR. FALCONE: Correct.

MR. GOODMAN: Am I correct that Hurricane Sandy caused electric service interruptions to approximately 97 percent of the customers?

MR. FALCONE: Correct.

MR. GOODMAN: Am I also correct that Hurricane Sandy also had the following impacts through Long Island:

There was extensive flooding, correct.

MR. FALCONE: Yes.

MR. GOODMAN: High winds throughout he service territory, correct?

MR. FALCONE: Yes.

MR. GOODMAN: We already discussed that there were pervasive service interruptions, correct, that lasted for as much as fourteen days or longer?

MR. FALCONE: Yes.

MR. GOODMAN: Is it also correct that Hurricane Sandy damaged tens of thousands of homes and businesses on Long Island?

MR. FALCONE: Yes.

MR. GOODMAN: I have a couple of questions regarding the storm hardening program. Initially though when I use the term "storm hardening and resiliency," I just want to make sure that we are clear on what I am referring to.

When I say "storm hardening and resiliency," do you understand me to be discussing capital investments that make the utility infrastructure less susceptible to storm-related outages and also improve the utilities' ability to restore services when there is an outage caused by storms?

MR. FALCONE: Yes.

MR. GOODMAN: Thank you. I may use the term storm hardening as short hand to refer to both hardening and resiliency, just to be clear.

Does the panel agree that storm hardening investments improve the system's ability to sustain services throughout severe weather? I believe you just said correct, yes.

MR. FALCONE: Yes.

MR. GOODMAN: And also we agree that those investments may shorten the time needed to restore service following an interruption, correct?

MR. FALCONE: Yes.

MR. GOODMAN: Am I correct that storm hardening investments may extend the life of certain utility assets by improving their ability to withstand severe weather, correct?

MR. FALCONE: Yes.

MR. GOODMAN: Do you agree that storm hardening investments may be economical over the long term because they do extend the life span of utility assets?

MR. FALCONE: Certainly theoretically possible.

MR. GOODMAN: Theoretically possible, but do you have a specific reason today to dispute the accuracy of that statement?

MR. FALCONE: I think we can stipulate we would expect assets be -- how about we just go with yes.

MR. GOODMAN: Do you agree that there are a number of utility assets -- again, using the term generally to any utility infrastructure, do you agree there are a number of utility assets that were not damaged by Hurricane Sandy?

MR. FALCONE: Yes.

MR. GOODMAN: Am I correct that the current storm hardening program is focused on hardening assets that were damaged by Hurricane Sandy, correct?

MR. FALCONE: There are multiple elements but the FEMA-funded program is restricted to assets that were damaged. One thing I would say is that damage was fairly widespread and covered most of the circuits, so that is fairly widespread.

MR. GOODMAN: But the FEMA grant is limited to 300 of the 900 or so distribution circuits; is that correct?

MR. FALCONE: Not precisely. I think it targets circuits, main-line circuits, in order by which we expect to have the greatest benefit. But if the money goes further than 300 main-line circuits, then more would be hardened. I think that is clear.

MR. GOODMAN: Is the panel aware that the City through the testimony submitted in this proceeding has recommended that LIPA and PSEG commence a collaborative process to discuss the storm hardening program?

MR. FALCONE: Yes.

MR. GOODMAN: We recommended that that collaborative process be modeled on the storm hardening resiliency collaborative currently being administered by Con Edison, correct?

MR. FALCONE: Yes.

MR. GOODMAN: Does LIPA oppose commencing a stakeholder process that would examine the storm hardening process and design standards?

MR. FALCONE: We don't oppose it, no.

MR. GOODMAN: Thank you. Nothing further, Your Honors.

JUDGE VAN ORT: Thank you. Any further questions? Gentlemen, you are excused. It is our understanding that the next two panels, PSEG Sales and Revenue Requirement Rebuttal Panel and the Department of Public Service Staff Sales Forecast Panel there are going to be no cross examination at this point.

Is that my understanding?

MR. WEISSMAN: That is correct, Your Honor.

MR. MILLER: That's correct, Your Honor. We got an admission from Staff that we would like to enter as an exhibit, and based on that we agree to waive any cross examination of the Staff panel.

JUDGE VAN ORT: Do you wish to address it at this time?

MR. MILLER: Yes (handing).

JUDGE VAN ORT: For the benefit of the record, what we have been provided with is an admission on behalf of The Department of Public Service, counsel for the Department of Public Service, with respect to the sales. The admission, I will read it briefly. It says, "Pursuant to 16 NYCRR Section 5.5, please admit that the answer for the following question is yes. Does Dr. Anping Liu agree that he did not take into consideration sales results from January 2015 through May 2015 when he updated his Commercial and Industrial sales forecast on June 18, 2015."

We have marked that as Exhibit 102 for identification at this point. Any objection to this coming into the record?

MR. BROCKS: No, Your Honor.

JUDGE VAN ORT: Thank you. It will be admitted as Exhibit 102.

MR. FAVREAU: Your Honor, also the updated testimony of Dr. Liu has already been provided to the court reporter, and it has been provided to the parties via email on Friday in both red line and in clean. We do have hard copies.

JUDGE VAN ORT: Why don't we take them now so we can complete the sales part of this.

MR. FAVREAU: Just the clean I presume?

JUDGE VAN ORT: I would like a clean and a red line copy.

MR. FORST: (Handing).

JUDGE VAN ORT: For the parties' benefit, Mr. Forst has also distributed to us a set of updated exhibits.

MR. FAVREAU: Your Honors, those updated exhibits have been premarked, and they are number 79 on this exhibit list.

JUDGE VAN ORT: Thank you, Mr. Favreau. We are going to return to these later on. You can make your offer of the exhibits into the record as we have been with these other exhibits we haven't addressed yet. I just want to have those in hand at this point in time. The next party for which we have testimony or cross examination scheduled is the Staff Inflation and Productively Panel; is that correct?

MR. MAZZA: Yes, Your Honor, that's correct.

JUDGE VAN ORT: I believe we have scheduled cross examination by PSEG. Is that the only party? Do you want to proceed?

MR. MAZZA: Good morning. Witnesses Christopher Grim and Daniel Pohoreckyj, members of the Staff Inflation and Productivity and Management Audit Panel. I show you thirty pages of questions and answers.

JUDGE VAN ORT: One moment, Mr. Mazza. I should have the witnesses sworn first.

MR. MAZZA: I'm sorry.

EXAMINATION BY
MR. MAZZA:

JUDGE VAN ORT: Gentlemen, would you raise your right hand, please. Do you swear or affirm that the testimony you are about to give in this proceeding is the truth, the whole truth and nothing but the truth?

MR. GRIM: I do.

MR. POHORECKYJ: I do.

JUDGE VAN ORT: Thank you. You can proceed.

MR. MAZZA: Thank you, Your Honor. I will begin again. Witnesses Christopher Grim and Daniel Pohoreckyj, members of the Staff Inflation and Productivity and Management Audit Panel. I show you thirty pages of questions and answers. The first page of which appears the caption of this matter and your names.

Was this testimony prepared by you or under your direct supervision?

MR. GRIM: Yes.

MR. MAZZA: Do you wish to make any updates to this testimony?

MR. POHORECKYJ: No.

MR. GRIM: No. Oh, the red line copy. I would like to submit the red line copy.

JUDGE VAN ORT: Mr. Grim, could you hold your button down, please?

MR. MAZZA: Could you repeat that please, Mr. Grim?

MR. GRIM: The red line has my updated version of my testimony.

MR. MAZZA: Your Honors, the updated version of this panel's testimony has been circulated to the party, and we do have the hard copies available.

Members of the panel, if I were to ask you today the questions contained in your testimony as updated, would your answers under oath be the same?

MR. POHORECKYJ: Yes.

MR. GRIM: Yes.

MR. MAZZA: Do you now adopt this testimony as updated for the purposes of this proceeding?

MR. GRIM: Yes.

MR. MAZZA: Your Honors, I ask that the testimony of the Staff Inflation, Productivity and Management Audit Panel be copied into the record as though given orally.

JUDGE VAN ORT: Thank you. So granted.

MR. MAZZA: Moving to your exhibits, did you prepare or identify any exhibits to accompany your testimony?

MR. GRIM: Yes.

MR. MAZZA: Are the documents identified as Exhibit IPMA-1 those exhibits?

MR. GRIM: Yes.

MR. MAZZA: Do you wish to make any updates to those exhibits?

MR. GRIM: No.

MR. MAZZA: Thank you.

Your Honor, I ask that the exhibits be marked for identification.

JUDGE VAN ORT: Do you have the pre-filed number for that, Mr. Mazza?

MR. MAZZA: It's number 80, Your Honors.

JUDGE VAN ORT: Thank you.

MR. MAZZA: I now present the panel for cross examination.

JUDGE VAN ORT: Mr. Miller, are you conducting the cross?

MR. MILLER: Yes, Your Honor, I am.

JUDGE VAN ORT: Just to note, since you are going to conduct cross, that the testimony be copied in as if orally given.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

In the Matter of a

THREE YEAR RATE PROPOSAL FOR ELECTRIC RATES AND CHARGES SUBMITTED BY THE LONG ISLAND POWER AUTHORITY AND SERVICE PROVIDER, PSEG LONG ISLAND LLC

Matter Number 15-00262

June 2015

Updated Prepared Testimony of:
Staff Inflation, Productivity and Management Audit Panel

Christopher Grim
Public Utilities Auditor III

Daniel Pohoreckyj
Senior Auditor

State of New York
Department of Public Service
125 East Bethpage Road
Plainview, New York 11803

Q. Please state the names of the members of the Inflation, Productivity and Management Audit Panel, or Panel.

A. Our names are Christopher Grim and Daniel Pohoreckyj.

Q. Mr. Grim, please state your business address.

A. My business address is 125 East Bethpage Road, Plainview, NY 11803.

Q. Mr. Grim, by whom are you employed and in what capacity?

A. I am employed by the New York State Department of Public Service in the Long Island Office, which the Panel will refer to as Department or DPS, as a Public Utilities Auditor III.

Q. Please describe your educational background and experience.

A. I graduated from Baruch College, C.U.N.Y. with a Bachelor’s Degree in Business Administration and majoring in Accounting. I have been in the employ of DPS since December 1979. Since that time I have been involved in numerous accounting examinations involving the companies regulated by the New York State Public Service Commission, or Commission, including rate cases filed by a municipal electric company, various small and large water companies and a gas and electric utility.

Q. Have you previously testified in any utility rate proceedings?

A. Yes. I have testified in rate cases involving water companies, a municipal electric company and a gas and electric utility.

Q. Mr. Pohoreckyj, please state your business address.

A. My business address is 125 East Bethpage Road, Plainview, New York 11803.

Q. By whom are you employed and in what capacity?

A. I am employed by the New York State Department of Public Service as a Senior Auditor.

Q. Please summarize your education and work experience.

A. I possess a Bachelor’s Degree from the State University of New York-College at Old Westbury specializing in accounting and a Masters of Business Administration specializing in Finance from Dowling College. I have 23 years of utility experience with LILCO, Keyspan, and National Grid including nine years in Customer

Relations, five years in Corporate Regulatory and Financial Accounting, five years as a Fixed Asset Accounting Supervisor, and four years as a Budget Analyst in Electric Generation support. I began my employment with the Department of Public Service in November 2014.

Q. Have you previously testified in any utility rate proceedings?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to review the inflation rates and productivity adjustments utilized by PSEG LI in the three year rate plan it proposed on behalf of LIPA and itself. In addition, we will review the implementation status of the Management Audit recommendations made by NorthStar Consulting Group, Inc. in Matter Number 12-00314.

Q. Are you proposing any adjustments in this proceeding?

A. Yes, we are, we are proposing adjustments to the inflation rates and productivity .

Q. In your testimony, will you refer to, or otherwise rely upon, any information produced during the discovery phase of this proceeding?

A. Yes, we will refer to, and have relied upon, several Company responses to Department Staff's Information Requests, or IRs. These responses are contained in Exhibit___(IPMA-1).

Inflation

Q. Are you recommending an inflation adjustment?

A. Yes. Our review of PSEG-LI's filing and accompanying work papers indicates that various escalating factors that were utilized by PSEG LI in developing expense levels for Rate Years 2016, 2017, and 2018 should be adjusted.

Q. Did PSEG LI satisfy its burden of proof regarding the use of various inflation escalators?

A. No. Even though PSEG LI cited vendor statements to support industry forecasted inflation factors, we believe PSEG LI did not satisfactorily demonstrate the need for varying factors. In addition, PSEG LI did not account for any expenses that are anticipated to grow at a lower rate than general inflation or decline over time.

Q. What is your recommendation?

A. We are recommending that the Gross Domestic Product Implicit Price Deflator or GDP-IPD be used as an inflation escalator and be applied to a pool of expenses, excluding contractual expense obligations, for each year of the three year period of the rate proceeding. Since the company did not segregate its contractual expenses, we applied the GDP-IPD to the Company’s O&M expenses.

Q. Please describe the GDP-IPD escalator that you recommend.

A. The GDP-IPD, is commonly used by the Department in forecasting cost elements. The GDP-IPD is a measure of the overall national economy and is, therefore, more indicative of the commercial activity of a utility than the Consumer Price Index or CPI which is a measure of consumer activity. Since the GDP-IPD is representative of the national economy there is no need to segregate the cost elements and apply different escalating factors as in PSEG LI’s rate proposal. The GDP-IPD takes this into account and is intended to reflect the reality that some costs go up at various rates and some costs go down at various rates.

Q. Do your numbers reflect the full recovery of the collective bargaining contracts which expire in November 2016?

A. Yes, our allowance reflects an increase of 2.25% for the rate year 2016 as set forth in the Memorandum of Agreement between Local 1049 and PSEG LI. We therefore propose that labor expense be forecast based on the contractual rate for the balance of the contract term. We recommend that our escalator be used to forecast labor expense for 2017 and 2018.

Q. Why a different factor for 2017 and 2018?

A. Due to the lack of a collective bargaining agreement for this period as an actual known benchmark, we recommend the use of the generic GDP-IPD escalation factor.

Q. How did you calculate the inflation rate for the three rate years?

A. First, we calculated the GDP-IPD escalation rate utilizing the Department’s Office of Regulatory Economics’ Inflation calculator.

Q. Please explain the significance of the Office or

Regulatory Economics’ Inflation calculator.

A. The Office of Regulatory Economics’ inflation calculator computes the inflation escalators using the historical and forecasted GDP price index as published by the US Bureau of Economic Analysis.

Q. What were your results?

A. Using 2015 as the base year, the forecast GDP-IPD inflation rate is 1.94% for 2016 and 2.1% for 2017 and 2018, respectively. We then applied these factors to PSEG LI’s 2015 expenses to arrive at the forecasted 2016, 2017, and 2018 rate year expense levels. The escalating factors were applied to the inflation adjusted expenses which were also adjusted for Staff’s operation and maintenance adjustments. Our recommended adjustment compares PSEG LI’s inflation expense to our calculated inflation expense. Use of the GDP-IPD results in a reduction of operations and maintenance expense of $6.5 million in 2016, $4.6 million in 2017 and $5.3 million in 2018.

Q. In your review, did you notice any charges in the base year 2015 that appeared to be non-recurring and or one-time in nature?

A. Yes. In 2015, the Company made a one time payment of $500 to each employee represented by collective bargaining. This equates to a total expenditure of $714,500. This is a non-recurring expense and needs to be removed from the 2015 base year and each of the subsequent three rate years.

Productivity

Q. Did PSEG LI propose a productivity adjustment?

A. Yes it did. PSEG LI’s proposed productivity adjustment is a self-imposed goal intended to contain increases in its operating expenses.

Q. Are you recommending a different adjustment to capture productivity?

A. Yes. PSEG LI’s methodology differs from the long standing method used by the Department. We are, therefore, recommending a productivity adjustment utilizing labor expense as the basis for the adjustment. The purpose is to promote an increase in any and all opportunities available to the Company to improve operating efficiency, and is a surrogate for anticipated overall productivity gains not meant to identify any specific source. This productivity adjustment is routinely used by the Department in electric, gas and water rate filings.

Q. How is the adjustment calculated?

A. Generally, one percent of the sum of labor and benefits expenses are applied to offset total O&M expense for each of the three rate years.

Q. How do your adjustments compare with the productivity adjustments proposed by the Company?

A. We compared our calculated adjustment with that which the Company presented on their Excel spreadsheet in response to Staff's informational request DPS-BP-438, to determine whether the one percent Department standard has been met. In rate years 2016 and 2017 the Company fell short of the standard by $1.7 million and $469,000 respectively. In rate year 2018 the Company exceeded the standard and therefore no adjustment is warranted.

Q. How are your adjustments, inflation and productivity, incorporated in the revenue requirement schedules?

A. We netted both adjustment with the Company's proposals and the results are: reductions in the Company's revenue requirement by $8.3 million in rate year 2016, by $5.1 million in rate year 2017 and by $5.3million in rate year 2018.

Management Audit

Q. What is the NorthStar Management Audit?

A. The NorthStar Management Audit is an audit that is similar to those conducted by the Department with respect to IOUs in the rest of the state. Like those audits, its intent is to improve utility company's operations, which leads to improved service levels and operating efficiencies. The NorthStar Management Audit of LIPA was authorized by the Long Island Power Authority Oversight and Accountability Act, which became law on February 1, 2012.

Q. Does DPS have a responsibility under the LRA to review the implementation of the NorthStar audit recommendations?

A. No, however, NorthStar recommended that the next management audit contain an evaluation of the implementation of all recommendations contained its report. LIPA has already accepted that recommendation. Since implementation will be reviewed in the next management audit, at this juncture we’re reporting on the progress of LIPA and PSEG LI efforts to implement the management audit recommendations.

Q. Were there any unique challenges associated with the NorthStar Management Audit?

A. Perhaps not unique, because industry work methods and technology change and advance over time and each audit may be considered unique, but the confluence of events surrounding the time period when the audit was conducted were particularly challenging.

Q. What challenges were encountered during the NorthStar audit?

A. Both LIPA’s organizational structure and regulatory regime were both in extreme flux, and the sensitivity of any matters surrounding LIPA in the wake of Hurricanes Irene and Sandy was extremely high.

Q. What changes were occurring in the organizational structure?

A. Prior to 2014, the day to day operations of the Long Island electric system were performed by National Grid under the Management Services

Agreement, or MSA. The MSA expired on December 31, 2013, and in preparation for its expiration, LIPA conducted a competitive solicitation for Service Providers to operate the Long Island electric system commencing January 1, 2014. PSEG LI was the successful bidder and became responsible for day to day electric system operations.

Q. From an audit perspective, what is the significance of this change in service provider?

A. A typical analysis would be to begin examining the status quo, identifying weaknesses that the new entity can overcome and highlighting opportunities for improvement. In this instance an entirely new management structure was being implemented and the historic analysis is not necessarily applicable to the incoming management team.

Q. Is this a fatal flaw in the NorthStar audit?

A. No, NorthStar made recommendations that it felt were applicable under any circumstances, but one must be cognizant that effective implementation of management audit recommendations, could be delayed and may need to be modified as the new management team and company begin operations.

Q. What changes were occurring in LIPA’s regulatory regime?

A. In the aftermath of Hurricanes Irene and Sandy, the Governor convened a Moreland Commission, which led in part to the enactment of new legislation known as the Long Island Power Authority Reform Act, and ultimately led to a Revised and Restated Operations Services Agreement or OSA.

Q. What’s the significance of the change in LIPA’s regulatory regime?

A. The reasons for its significance are threefold, first was the need to integrate an entirely new management structure which had the potential to create uncertainty as to whether the level of electric service would decline.

Q. What’s the second item you find to be of significance?

A. The Amended and Restated OSA fundamentally changed the relationship between LIPA and the Service Provider, by expanding PSEG LI’s responsibility for the electric system, and essentially making PSEG LI the face of the Long

Island electric system. This further attenuates the new reality from the results of historic operations. Those results could under normal operating circumstances be extrapolated into specific future improvement opportunities.

Q. What is the third factor you find to be of significance?

A. The placement of the Department in an oversight and advisory role to the LIPA Board of Trustees on a variety of matters such as rates, storm performance, and construction budget review.

Q. What’s the significance of this third item?

A. It takes two forms; first heretofore LIPA’s Board of Trustees had been able to make decisions somewhat unilaterally. As a result of the LIPA Reform Act, the Board’s decision making must now take into account DPS recommendations. Second, the Amended and Restated OSA also includes an assumption as to a dramatically reduced LIPA staff, consistent with PSEG LI’s larger role in decision making. The advisory role of the Department can provide guidance to the LIPA BOT that was previously provided by LIPA staff.

Q. Did the NorthStar audit take into account the Amended and Restated OSA?

A. No, although the audit recognized that an amended OSA was being developed, the field work for the audit was completed from April through June 2013. As described in the NorthStar Audit report its audit work preceded the LIPA Reform Act and only took into account the original OSA dated December 28, 2011.

Q. Is this a fatal flaw in the NorthStar Audit?

A. No, as noted above, NorthStar made recommendations that would be applicable under any circumstances, and these recommendations can be categorized into certain broad themes. Given the dramatic change in the regulatory environment since the NorthStar Audit, and the implementation of the Amended and Restated OSA, it is more useful to look at the broad themes associated with compliance with NorthStar's recommendations rather than an examination of individual recommendations.

Q. Does the NorthStar audit lend itself to examination of such themes?

A. Yes, in its overview of audit findings and conclusions, NorthStar identified six such themes.

Q. Before you begin discussing the broad themes, please provide the current status of LIPA and PSEG LI’s compliance with the Management Audit recommendations?

A. In its testimony, the LIPA Overview Panel reported that it implemented 35 of 43 applicable recommendations, and that PSEG LI completed 20 of the 40 applicable recommendations. Both LIPA and PSEG LI express their intention to complete implementation of all applicable recommendation by year end.

Q. Have any LIPA or PSEG LI panels commented on the NorthStar management audit?

A. Yes, several have, most notably Mr. Shansky’s testimony in which he discusses the role of the Contract Oversight Committee in overseeing PSEG LI’s operational and service performance. Given LIPA’s smaller workforce, and the need for it to increase its utility management IQ, the LIPA Oversight Committee is dedicated to the targeted review of PSEG LI’s performance and has the ability to assemble and target the appropriate staff to conduct a review.

One example is the Customer Services Budget and Operations Panel that reports in its testimony 11 of the 13 recommendations assigned to Customer Services have been completed and the remaining two are in the process of being reviewed.

Although not mentioned as specifically relating to the NorthStar audit, the Capital Budget Panel identified an Investment Evaluation System to evaluate construction projects that will be implemented in 2015. The significance of this from a management audit perspective is that this is the same system used by all PSEG companies and addresses a concern raised in the management audit that LIPA’s interests not be subordinated to PSEG’s, in this instance PSEG is treating LIPA on par with its own subsidiaries.

Q. How detailed will your description be of LIPA and PSEG LI’s performance with respect to the audit recommendations?

A. Our description of LIPA and PSEG LI’s performance will be a general discussion of some of the progress that has been made in furthering the broad themes identified in the audit report.

Q. What is NorthStar’s first theme?

A. A fully contracted utility operation such as LIPA, operating without a traditional command and control structure, is critically dependent on its “utility management IQ” to be successful.

Q. What is your assessment in this area?

A. According to the Audit Report, LIPA operated as a contract administrator in its relationship with National Grid and did not have an appreciation of its responsibility to provide safe, reliable, electric service to the residents of Long Island. The Audit report also found that the LIPA Board of Trustees historically approved the total capital budget with minimal information on the projects included. LIPA has an opportunity to increase its utility IQ quickly by taking advantage of DPS oversight of LIPA operations, and factor DPS recommendations into LIPA’s decision making. This is especially important given the increased role PSEG LI plays due to the significantly reduced number of LIPA staff.

Q. Has LIPA fully utilized the knowledge and

expertise provided by DPS in this regard?
A. The new regulatory regime incorporating DPS oversight has only been in effect for little more than a year, but in that time among the areas on which DPS has advised and made recommendations to LIPA and PSEG LI are tariff filings, emergency response plans and storm preparation, construction budgets and rate matters.
Q. I understand that the specifics will be reviewed in the course of the next management audit, but do you have some examples of recommendations which LIPA and PSEG LI report they have implemented?
A. Yes, in the response to IR DPS-OP-417 LIPA reported the implementation of two recommendations in furtherance of this theme.

- Actively recruit and retain personnel with a strong understanding of all aspects of utility operations, including T&D activities, customer service functions, capital project management, and rates and regulatory activities.
- Conduct a detailed review of proposed capital projects and expenditures with the BOT as part

of the capital budget approval process.

Q. What is NorthStar's second theme?

A. As the entity ultimately responsible for the provision of electric service on Long Island, LIPA has to keep its contractors accountable for results: all the time. The service provider contract must drive performance, allowing LIPA to exercise its responsibilities as system owner and intervene as necessary to improve performance.

Q. What is your assessment in this area?

A. Our analysis was hampered by the difficulty in obtaining historic financial data that in accordance with the Transition Services Agreement, or TSA, remained under the control of National Grid and which PSEG LI was unable to readily obtain. With the introduction of a program called Systems, Applications, and Products in Data Processing by PSEG LI in January 2015, we expect that LIPA and DPS will have more comprehensive access to historic data which will better enable both parties to assess performance. One of the primary tools available to LIPA to keep PSEG LI accountable and drive performance is applicability of the metrics as set forth in the Amended and Restated OSA. Compliance with the applicable metrics is required for PSEG LI to earn incentive.

Q. Does DPS have oversight of compliance by PSEG LI with the metrics?

A. Yes. The first annual review of the applicable metrics included in the Amended and Restated OSA will be completed by DPS later this year. This will follow the submission of data to DPS for its review in assessing the performance of PSEG LI in order to determine PSEG LI's incentive compensation in accordance with the metrics. It is difficult to assess the adequacy of the metrics at this juncture as a means of overseeing PSEG LI's performance, but the combination of more comprehensive data availability and review of performance is expected to enhance LIPA's ability to hold PSEG LI accountable for its performance.

Q. I understand that specific recommendations will be reviewed in the course of the next management audit, but do you have some examples of recommendations in this area which LIPA and PSEG

claim to have already been implemented?
A. Yes, in IR DPS-OP-417 LIPA has reported the implementation of two recommendations that further the intent of this theme.

- Develop a Monthly Operating report (in conjunction with PSEG LI) to provide the LIPA Executive Team and BOT with the key information from the entire organization’s activities needed for oversight and control.
- Strengthen the capabilities and commitment to Internal Audit within the Authority, including dedicated personnel with utility operations and auditing experience.

Q. What is NorthStar’s third theme?
A. LIPA’s customers deserve to be treated with maturity and respect, to receive accurate and timely information about system operations, rates and performance, and to have appropriate levels of service.
Q. What is your assessment in this area?
A. According to the Audit report, LIPA’s performance has been categorized as extremely poor in perception-based customer satisfaction surveys such as JD Power. The Audit report

explains that under the MSA with National Grid, LIPA was not made aware of customer service issues, customer service performance targets were below industry standards and LIPA’s customers appear to have expected low service levels. In the aftermath of Hurricane Sandy, as the Audit report found, the customer service and communications functions were distributed throughout the organization and as a result, customer service received less emphasis. With the introduction of PSEG LI as service provider, customers see a new entity providing electric service. However, public perception will not change quickly or solely as a result of the change of service provider.

Q. I understand that specific recommendations will be reviewed in the course of the next management audit, but do you have some examples of recommendations that LIPA and PSEG LI report they have already implemented?

A. Yes, in IR DPS-OP-417 LIPA, reported the implementation of two recommendations that further this theme.

- Immediately develop and implement a

communications strategy and message to set customers expectations for the upcoming storm season. Communications should address outages, outage management systems, and storm response/restoration processes and the roles of LIPA, National Grid, and PSEG LI for this season.

- Improve communications of rate and tariff changes, in conjunction with PSEG LI’s communication and customer service functions.

PSEG has reported the implementation of three recommendations.

- Communicate issues of significance to customers regularly and in a timely manner.
- Develop more robust plans for handling the call volumes possible during a major storm.
- When under emergency conditions consistently follow the communications plan and provide customers with regular updates even if limited information is available.

Q. What is NorthStar’s fourth theme?

A. LIPA cannot be subordinated to the service provider’s core utility operations.

Q. What is your assessment in this area?

A. One reason why LIPA chose PSEG LI to be its service provider was due to PSEG's excellent reputation in New Jersey for its operations and customer relations.

Q. I understand that specific recommendations will be reviewed in the course of the next management audit, but do you have some examples, of recommendations which LIPA and PSEG report they have already implemented?

A. Yes, in IR DPS-OP-124 PSEG LI has reported the implementation of one recommendation that furthers this theme.

Immediately develop a plan for addressing the culture changes and re-education necessary to ensure the existing National Grid workforce fosters and promotes the same values as espoused by PSEG.

Q. What is NorthStar's fifth theme?

A. The authority deserves to receive outstanding performance from its providers and should only pay premiums for performance above the current norms.

Q. What is your assessment in this area?

A. Premiums, which are being interpreted here as incentive plan payments, were established in the Amended and Restated OSA. The Amended and Restated OSA provides that levels are designed to maintain performance in areas where results are in the first quartile, and enhance performance for others over a five year period such that a first quartile result is achieved. In accordance with the Amended and Restated OSA, metrics are subject to change, and Staff will comment on the need for metric changes after it reviews the report on PSEG LI’s performance related to the metrics and the incentive payment proposal by PSEG LI later this year.

Q. I understand that specific recommendations will be reviewed in the course of the next management audit, but do you have some examples of recommendations which LIPA and PSEG assert have already been implemented?

A. Yes, in IR DPS-OP-417 LIPA has reported the implementation of one recommendation that furthers this theme.

Within the first year of the OSA, conduct a thorough, technical review of the OSA metrics (Tiers 1,2, and 3) to fully document the basis for the metrics, key drivers and relationships, leading/lagging nature, benchmarks and performance at other utilities, and possible data and reporting issues.

Q. What is NorthStar’s sixth theme?

A. Functional areas where LIPA is performing well should be preserved and supported through the transition to PSEG-LI and the Servco model. Three such areas were mentioned in the audit report.

Q. What was the first area?

A. System Maintenance and Reliability. As noted above, metrics were designed to either maintain or improve operations. The major system maintenance and reliability metrics are System Average Interruption Duration Index, or SAIDI, System Average Interruption Frequency Index, or SAIFI, and Customer Average Interruption Duration Index, CAIDI. These metrics are in the maintenance category because PSEG LI performance is already in the first quartile. It does not appear that any changes are being implemented that would jeopardize this performance.

Q. What is the second area?

A. System Planning. System Planning will be greatly influenced by the REV/Utility 2.0 activities and PSEG LI has been an active participant in the Department’s REV proceeding. This is one example of the intention of PSEG LI to improve its system planning.

Q. What is the third area?

A. Power Supply Procurement and Management. This function has been transferred to PSEG LI effective January 1, 2015.

Q. What is your assessment in this area?

A. It is premature to comment on the success or lack thereof with respect to implementing this function.

Q. I understand that specific recommendations will be reviewed in the course of the next management audit, but do you have some examples, of recommendations which LIPA and PSEG LI assert to have already been implemented?

A. Yes, in IR DPS-OP-417 LIPA has reported the implementation of two recommendations that further this theme.

- LIPA will include at least one aspect of the power supply management function in its Internal

Audit plan every year, so that over time Internal Audit would review the management of the power supply contracts, fuel procurement activities, near-term power supply management, the middle office monitoring program, and the energy price risk hedging program.

- Contract for an independent evaluation of the actual effectiveness and achievements of the current energy efficiency initiatives and programs, including verification of energy and capacity savings actually achieved in field installations.

PSEG has reported the implementation of three recommendations.

- PSEG has increased the effectiveness of the vegetation management program by further refining analysis of tree-related reliability.
- PSEG has also assessed the value of continuing LIPA’s Load Research Program, and investigated the potential value to forecasting and energy efficiency program development of periodic residential and commercial appliance saturation and end user surveys.
- PSEG will also maintain, to the extent possible,

the current energy supply planning processes, resources, organization, and tools under the Servco model.

Q. Does this conclude your testimony?

A. Yes, at this time.

CROSS EXAMINATION BY
MR. MILLER:

JUDGE PHILLIPS: Also, just a reminder, please use your microphone when answering the questions. You probably have to hold the button down.

MR. MILLER: As preliminary, Your Honor, we have one document that I would like to have marked for identification. I would like to show it to the witnesses and give out copies.

JUDGE VAN ORT: This document is not on the exhibit list?

JUDGE PHILLIPS: This is a new one, I believe.

MR. MILLER: No. We just got the response, Your Honor, I think on Monday.

JUDGE VAN ORT: Okay.

MR. MILLER: (Handing).

JUDGE PHILLIPS: Counsel is circulating a one-page document labeled PSEG Long Island, matter number 15-00262 discovery request for PESEG LI-IPMA-0014. It has been marked for identification as Exhibit 103.

MR. MILLER: We will return to this. I would just like to authenticate it. Was the answer to this discovery request prepared by you or under your supervision and direction, Mr. Grim and Mr. Pohoreckyj?

MR. GRIM: Yes.

MR. MILLER: I misspoke. Let's go back to this exhibit that was marked 103 for a second. The panel submitted recently revised testimony; is that correct?

MR. GRIM: That's correct.

MR. MILLER: Was that submitted in response to this discovery request?

MR. GRIM: I think it may have been the revised testimony.

MR. MILLER: Do you have your microphone on, Mr. Grim?

MR. GRIM: Yes. The revised testimony -- excuse me a second.

MR. MILLER: Let me ask you a specific question, Mr. Grim. That might make this easier. If you look at the document I had marked as Exhibit 103 in response to number one, do you see that?

MR. GRIM: Yes.

MR. MILLER: You say in response "Yes we agree there are several double counts." Is it your testimony that your revised testimony that was submitted this morning takes care of or accommodates all of those double counts?

MR. GRIM: I believe it does.

JUDGE PHILLIPS: When you say "accommodate," do you mean "eliminate," just for clarification?

MR. MILLER: What I meant was that if there were double counts, those double counts would be eliminated and affect the revenue requirement, Your Honor.

JUDGE PHILLIPS: Thank you.

MR. MILLER: Is that correct, Mr. Grim?

MR. GRIM: Yes.

MR. MILLER: There aren't any others? They are all in your recently revised testimony?

MR. GRIM: Anymore what? I don't follow. Anymore what?

MR. MILLER: I guess the question is, you say that there are several double counts. I just wanted to make sure that they are all picked up in the testimony you just revised.

MR. GRIM: Yes, they are.

MR. MILLER: You picked up those double counts in the response to the interrogatory that was submitted that this was a response to?

MR. GRIM: Yes.

MR. MILLER: We will return to this. Let's just discuss your inflation adjustment. Am I correct that the Public Service Commission in New York has followed a policy in its rate cases of applying a forecasted inflation rate to a market basket or pool of expenses that don't warrant the time and trouble of making specific forecasts; is that correct?

MR. MAZZA: Your Honor, I would like to object to the characterization of warrant the time and trouble to make a specific forecast.

MR. MILLER: Let's limit the question. Make your point, Mr. Mazza.

Let's limit the question to has the Commission applied an inflation rate to a pool of categories of owing an expense in the past?

MR. GRIM: The policy is that the inflation escalate is applied to, yes, a pool of expenses.

MR. MILLER: Mr. Grim, I am going to refer to a commission decision in a Rochester Tel case. I am going to ask you three questions.

Has the Commission stated that one of the purposes of including an item in a pool of expenses to which inflation is applied is to save time and effort?

JUDGE VAN ORT: Mr. Miller, while they are discussing that, could you provide me with the case number for that?

MR. MILLER: Yes, Your Honor. It is 89C022 Rochester Tel. It is Opinion 90-8.

JUDGE VAN ORT: Thank you.

MR. GRIM: Mr. Miller, would you please repeat the question?

MR. MILLER: Yes. Are you aware that one of the reasons the Commission has stated for putting an O&M item in the expense pool is by doing so is to save time and effort?

MR. GRIM: That is not my understanding.

MR. MILLER: Has the Commission also stated that a reason for putting an O&M item in the expense pool is to avoid unnecessary litigation?

MR. GRIM: That does sound reasonable to me.

MR. MILLER: Did you say sounds reasonable to you?

MR. GRIM: Yes.

MR. MILLER: Is the third item the Commission has given is that putting that O&M item in the inflation pool will provide a reasonably accurate estimate of the expense?

MR. GRIM: I'm not familiar with the Commission opinion on that particular case, so I don't feel I can comment properly on it.

JUDGE VAN ORT: Mr. Grim, could you back up to the second question that Mr. Miller asked. The reason being to prevent or to avoid unnecessary litigation, you said something to the effect that I believe that's the case.

Are you referring to your opinion that it is reasonable, or is that your understanding of what the commission has determined?

MR. GRIM: My opinion.

MR. MILLER: Gentlemen, you testified in a number of PSC rate cases; is that correct?

MR. POHORECKYJ: I have not.

MR. GRIM: I have.

MR. MILLER: Mr. Grim, isn't it true that even in the usual PSC rate case there are many larger items of cost categories of O&M expense for which specific forecasts are made of those expenses?

MR. MAZZA: Your Honor, I would ask that Mr. Miller address the panel as a panel rather than individually.

JUDGE VAN ORT: I think he was simply just deferring to Mr. Grim because of the level of experience he had. It is fine. If he addresses the panel and Mr. Grim answers the question that is fine. The panel can understand the question is addressed to you. Whether one of you addresses it or Mr. Grim addresses it or your co-panel addresses it is up to you.

MR. MILLER: Do you recall the question, Mr. Grim?

MR. GRIM: Would you please repeat the question?

MR. MILLER: Isn't it the case that in many PSC rate cases large categories of cost, O&M costs, are specifically and individually forecast rather than having those O&M expense items put in the inflation pool?

MR. GRIM: I don't know exactly how many cases you are talking about. My research in the last Con Edison and O&R case, I know staff had rejected isolating certain cost elements and escalating them separately from the pool and that went into the joint proposals in those cases, but I am not familiar with individual cost elements in large magnitude being separated.

MR. MILLER: What cases did you say, Mr. Grim? You are talking about Con Ed and O&R? Are those the cases you used?

MR. GRIM: That's correct.

MR. MILLER: What specific O&M items were forecasted in those cases separately and not put in the inflation pool?

MR. GRIM: To my understanding, none. They're all in the.

Inflation pool. The staff rejected individual cost elements and applying escalated factors to them.

MR. MILLER: Was that a litigated case or a settled case?

MR. GRIM: I believe it was settled because Staff's position went to JP, joint proposal.

MR. MILLER: Are you aware of other cases where, for example, wages and salaries were separately forecasted?

MR. GRIM: The contractual component of wages and salaries would not go into the inflation pool.

MR. MILLER: I'm sorry. I missed that. Wages and salaries, I am asking if you are aware of cases where wages and salaries were not put in the inflation pool.

MR. GRIM: I'm not aware of any specific case.

MR. MILLER: Mr. Grim, in your original testimony did you apply the forecast of inflation to the collective bargaining agreement for 2016?

MR. GRIM: Yes.

MR. MILLER: And you changed that testimony, didn't you?

MR. GRIM: That's correct.

MR. MILLER: Why did you change your testimony?

MR. GRIM: I changed the testimony to reflect the agreement between PSEG and Local 1049 that they would have a 2.25 percent increase in November of 2016. My original adjustment schedule did not reflect that. I was aware of it but it was too late to adjust the schedule so put it off.

MR. MILLER: So where there was a contractual term that uses an increase that is different than the inflation rate, you would recognize that contractual term, wouldn't you?

MR. GRIM: That's correct.

MR. MILLER: Would you limit it just to collective bargaining agreements?

MR. GRIM: I'm sorry, would you repeat the question? I didn't hear it.

MR. MILLER: You agree with me that if there was a contractual term that inflated some expense, some O&M expense, at a different rate than the inflation rate you would feel compelled to use the contractual rate or increase rate rather than the inflation rate, correct?

JUDGE VAN ORT: Mr. Miller, can I just ask a point of clarification? Are you referring to individual officers that may have a management contract with the company, or are we talking about something different?

MR. MILLER: No, something different, Your Honor. We are talking about in this case the union wage rate, and then I changed the subject to any contract.

JUDGE VAN ORT: That is what I am referring to. I understand the CBA, the collective bargaining agreement, component of it. I think that is what you were discussing up to this point. Now you are referring to non-collective bargaining, non-union employees; is that correct?

MR. MILLER: That's correct, Your Honor.

MR. GRIM: Would you kindly repeat the question?

MR. MILLER: Mr. Grim, you said to me that you originally applied the inflation rate to collective bargaining agreement. Do you recall that?

MR. GRIM: Yes.

MR. MILLER: Then you said when you realized the collective bargaining agreement ran through November 2016 and it had a rate of inflation is it, you used the rate of inflation in the collective bargaining agreement rather than your forecasted inflation rate, correct?

MR. MAZZA: I don't believe that is a correct characterization of what Mr. Grim answered previously.

MR. GRIM: I don't interpret what was in the collective bargaining agreement as inflation. It was negotiated an amount and basically considered a known change. Known changes would be incorporated in my tabulations.

MR. MILLER: If there is a known change in a contractual agreement, that would be the appropriate method to use to inflate an O&M expense item. Do you agree with that?

MR. GRIM: Yes.

MR. MILLER: So, for example, in a facility's lease agreement if there were to be an increase schedule by a contract, it would be appropriate to use that increase rather than the inflation rate, wouldn't it?

MR. GRIM: That's considered a known change and, yes, I would incorporate that in my schedules. I don't consider that inflation. If it's known, we accept that especially if it's contractual. I would incorporate that at that rate in my schedule in my adjustment, calculation of my adjustments.

MR. MILLER: How about quotes from vendors, did you reject those.

MR. GRIM: Yes, I did.

MR. MILLER: You substituted in their place the GNP implicit price deflator forecast?

MR. GRIM: Right.

MR. MILLER: In fact, Mr. Grim, for all of PSEG's O&M expenses, isn't it correct that you used the forecast of the GNP implicit price deflator rather than the separate forecasts that were made?

MR. GRIM: Would you please repeat the question?

JUDGE PHILLIPS: Before you do that, just one minute. Could you please repeat the question?

MR. MILLER: Let me amend the question. Mr. Grim, with the sole exception of your use of the 2016 collective bargaining agreement increase, is it correct that for every other category of O&M expense you used the GNP price deflator forecast rather than the separate forecast made by PSEG Long Island?

MR. GRIM: It is correct. Yes, I did apply the GDP price deflator to all the cost elements other than the collective bargaining agreement.

MR. MILLER: Mr. Grim, are you familiar with the operating services agreement between LIPA and Public Service Electric and Gas of Long Island?

MR. GRIM: Yes, I am.

MR. MILLER: Are you aware of any provision of the operating services agreement that limits PSEG Long Island's O&M expenses to the rate of inflation?

MR. GRIM: No.

MR. MILLER: Are you aware of how the OSA, OSA meaning operating service agreement, treats the expenses of the general workforce including wages and benefits?

MR. MAZZA: Your Honors, to the extent that this calls for legal analysis of the OSA, I would object to the questions.

MR. MILLER: I am asking if he knows.

JUDGE VAN ORT: If the witness can answer this, he would simply be answering as to what he is aware of. He is not making a legal interpretation of that provision, that is acceptable.

MR. GRIM: May I have the question again, please?

MR. MILLER: Are you aware of how the OSA treats expenses for the general workforce including wages and benefits?

MR. GRIM: It is my understanding expenses are incurred by PSEG Long Island are passed-through expenses.

MR. MILLER: You agree we are setting rates here for a three-year period?

MR. GRIM: Yes.

MR. MILLER: I would like to give you a hypothetical. Let's assume an expense is escalated at 10 percent for the year. Let's assume that expense is $100.

Would you agree with me that compounded at the end of three years that expense would have risen to $133?

MR. GRIM: Without being a compounding expert, I would say yes.

MR. MILLER: How about the same $100 expense, Mr. Panel, inflated at your average inflation rate of 2 percent, would you agree that at the end of the third year you are at $106?

MR. GRIM: No.

MR. MILLER: What would you say?

MR. GRIM: It would be more than $106. It would be compound in effect.

MR. MILLER: $106 and change at 2 percent?

MR. GRIM: Yes.

MR. MILLER: At the end of three years that $100 that grew at 10 percent is now 27 percent larger than using your 2 percent inflation rate, correct?

MR. GRIM: Without doing the math, I would agree with it.

JUDGE PHILLIPS: Can I just ask a clarifying question? Did you say 27 percent when you asked the question or $27?

MR. MILLER: Using the hundred base, I guess it's pretty close but either one, $27 higher.

JUDGE PHILLIPS: I'm just asking if you mean -- I thought you said percent. I just wanted to clarify. Did you mean that?

MR. MILLER: I probably did but my math skills are not legendary.

JUDGE PHILLIPS: I just want to make the record clear though. What was your intent? Was it 27 percent?

MR. MILLER: I have 27 percent written down.

JUDGE PHILLIPS: Okay. I just wanted to make sure. Thank you.

MR. MILLER: Thank you, Your Honor.

Let's turn to your productivity adjustment. You said you applied a one percent productivity adjustment per year to wages, salaries and benefits, correct?

MR. GRIM: Correct.

MR. MILLER: Am I correct also that that one percent productivity adjustment is a standard adjustment in Public Service Commission rate cases for investor-owned utilities?

MR. GRIM: Yes.

MR. MILLER: Hasn't the Commission stated many times with respect to the one percent adjustment that its purpose is to provide a continuing incentive to improve productivity?

MR. GRIM: Correct.

MR. MILLER: So, you are simply following the PSC's policy in investor-owned utility rate cases here; isn't that correct?

MR. GRIM: Yes.

MR. MILLER: Isn't the effect of your one percent productivity adjustment to reduce the revenue requirement in each of the years 2016, 2017 and 2018?

MR. GRIM: Yes.

MR. MILLER: I believe you agreed with me that you are familiar with the OSA between LIPA and Public Service Long Island, correct?

MR. GRIM: That was pertaining to passed-through expenses.

MR. MILLER: What was your answer, Mr. Grim?

MR. GRIM: As it pertains to passing through expenses incurred by PSEG Long Island to LIPA.

MR. MILLER: That and also more generally?

MR. GRIM: A bit more generally, yes.

MR. MILLER: That agreement was approved by the chair of the PSC, was it not?

MR. MAZZA: Object, Your Honor. The letter stands for itself -- speaks for itself. I'm sorry.

JUDGE VAN ORT: That is correct. If the witness can answer it as to what his understanding of it might be. If he has no understanding, he can simply state that. He doesn't have to go beyond the boundaries of that.

MR. GRIM: I do not know.

MR. MILLER: Do you know if the OSA contains performance incentives for PSEG Long Island?

MR. GRIM: Yes, I do.

MR. MILLER: And it does, doesn't it?

MR. GRIM: Yes.

MR. MILLER: Does it also contain performance penalties?

MR. GRIM: I'm not aware of any.

MR. MILLER: Do you know if your one percent productivity adjustment is referenced or contained anywhere in the OSA?

MR. MAZZA: Your Honor, this is outside the scope of the witness's testimony. He wasn't testifying with respect to the OSA incentive inflation and productivity adjustment.

JUDGE VAN ORT: Mr. Miller, can you give us an offer, proof as to where you are going with this? Maybe it will help us out in this process.

MR. MILLER: I think one of the things we have to realize is this case is that this is not a typical IOU case. The OSA does govern the agreement between PSEG Long Island and LIPA, and its terms have to be respected in this case as well. So, if the witness didn't look at it, that's fine but I think it's an important element of this case. This is not an investor-owned utility rate proceeding.

JUDGE VAN ORT: How does that relate to the productivity adjustment issue you are talking about, the one percent?

MR. MILLER: Well, Your Honor, because the productivity adjustment is essentially another incentive. We just established that in the colloquy that we had. So, given the fact that it's an incentive and the OSA contains incentives and penalties, I am trying to find out if this is another incentive that is being added to the OSA.

MR. MAZZA: Your Honor, I don't know that it was established that the OSA considered the productivity an incentive. I would differ with that interpretation.

JUDGE VAN ORT: We are going to go off the record for a minute.

(Whereupon, an off-the-record discussion was held.)

JUDGE VAN ORT: Gentlemen, we are going to give you a little bit of latitude in this regard. But one of the things we need to do, the two of us are sitting here looking at the testimony that was prepared and we are trying to draw the link back to the testimony.

Mr. Miller, as you are questioning, if you can assist us in that regard and tie it back to the testimony that they have prepared, that would be of help.

MR. MILLER: I think the question is no more complicated than asking if the one percent productivity adjustment appears anywhere in the OSA. If the witness doesn't know, that's fine. I don't intend to go any further than that.

JUDGE VAN ORT: Mr. Grim?

MR. GRIM: Mr. Miller, please repeat the question.

MR. MILLER: Again?

MR. MAZZA: Your Honor, argumentative.

JUDGE VAN ORT: Gentlemen, let's settle down. His question, let's see if I can rephrase. His question is simply does the one percent productivity adjustment that you stated in your testimony appear anywhere within the confines of the operating service agreement?

MR. GRIM: No.

MR. MILLER: Let's go to the exhibit that we had marked as Exhibit 103, your response to the interrogatory. Do you have that?

MR. GRIM: Yes.

MR. MILLER: Look at your response number two, please. The second sentence of that response says "In treating LIPA and PSEG Long Island analogously to an investor owned utility, it is appropriate to include OPEBs expense in the calculation of the productivity imputation adjustment."

Is that correct? That is what it says?

MR. GRIM: Yes.

MR. MILLER: Is LIPA an investor-owned utility?

MR. GRIM: No.

MR. MILLER: Do you know, is PSEG Long Island considered a utility under the LIPA Reform Act?

MR. MAZZA: Your Honor, that calls for a legal conclusion.

MR. MILLER: I am just asking if he knows.

JUDGE PHILLIPS: If you know, you can answer. I don't think it is calling legal conclusion. It is just if they know.

MR. GRIM: No.

MR. MILLER: Your Honor, just for ease of cross examination, Your Honor, I would like to give the witness a copy of a page from the exhibit that will be marked. It has been long in evidence. I will give Your Honors a copy as well. It will just be easier to follow along (handing).

JUDGE VAN ORT: What exhibit number?

MR. MILLER: RRP-1.

JUDGE PHILLIPS: Let's note for the record that the page that was handed out was exhibit previously marked as RRP-1, page 2 of 9. It has not been marked again because it is our understanding that it should be on the list of exhibits that was prepared by the parties. What I wanted to request though is the number that was given to it on that list?

MR. MILLER: The exhibit number?

JUDGE PHILLIPS: Correct.

MR. MILLER: It was RRP-1.

JUDGE PHILLIPS: No. You prepared a list of exhibits and it was assigned a number.

MR. MILLER: We are looking.

MR. FORST: Your Honor, I believe it was number 45.

JUDGE PHILLIPS: Thank you.

MR. MILLER: Thank you, Mr. Forst.

MR. FORST: You're welcome.

JUDGE VAN ORT: Mr. Forst, that Exhibit 45 is the entire 19 pages; is that correct?

MR. FORST: That is correct, Your Honor.

JUDGE VAN ORT: We only have one page, page two of that exhibit. Thank you.

Gentlemen, do you need time to look at this before a question is asked? Do you need the entire exhibit? There is a second question. You can answer.

MR. GRIM: We don't. We are fine. We can take questions now.

JUDGE VAN ORT: You do not need the full exhibit?

MR. GRIM: I believe I have a copy of it.

JUDGE VAN ORT: Mr. Miller?

MR. MILLER: Thank you, Your Honor. Let's do some background questions.

Can you define OPEBs for me?

MR. GRIM: They're benefits to former employees that they receive after retirement or post-employment.

MR. MILLER: Pensions of course are pension expense, correct?

MR. GRIM: Yes.

MR. MILLER: You are familiar with the term generally accepted accounting principle or GAAP, G-A-A-P?

MR. GRIM: Yes.

MR. MILLER: For an investor-owned utility when they calculate pension expense, is it not usually calculated on a GAAP basis?

MR. GRIM: Yes.

MR. MILLER: For an OPEB expense, isn't it also usually calculated on a GAAP basis?

MR. GRIM: Yes.

MR. MILLER: Are you aware that in this case for the public power model the pension expense was calculated on the lower ERISA minimum payment level?

JUDGE VAN ORT: Just as a point of clarification, it is calculated are you referring to PSEG or by Department of Public Service Staff?

MR. MILLER: No, Your Honor. It was calculated really through a collaboration between PSEG Long Island and the Long Island Power Authority based on the use of the public power model that the Long Island Power Authority favored.

JUDGE VAN ORT: Thank you.

MR. GRIM: Yes.

MR. MILLER: Are you aware that OPEB expense under the public power model used here is essentially calculated at zero using the cash basis that LIPA determined to use as zero amount for OPEB expense? Are you aware of that?

MR. GRIM: Yes.

MR. MILLER: Would you agree with me that the rates in this case are based on for pension expense the ERISA expense and not GAAP expense.

MR. GRIM: Yes.

MR. MILLER: Would you further agree that for rates in this case, OPEB expense is essentially at zero.

MR. GRIM: To clarify, could you tell us whether or not -- are you talking about them being included in the rate case or in the revenue department?

MR. MILLER: I didn't get your question, Mr. Grim.

MR. GRIM: Then would you please repeat your question?

MR. MILLER: Do you have one page, page 2 of 19, that you had that I showed you.

MR. GRIM: Yes.

MR. MILLER: Look under the PSEG Long Island expenses for pension. Do you see a figure of 73 million dollars there.

MR. GRIM: Yes.

MR. MILLER: Now go down the list and look at the LIPA expenses where deductions are made for non-cash items.

Do you see that? Do you see that same 73 million dollars is taken out there?

MR. GRIM: Yes.

MR. MILLER: Under the public power ratemaking model that we are using, ratepayers are not being asked to pay rates for that 73 million dollars, are they?

MR. MAZZA: Your Honor, I once again, say this goes beyond the scope of the testimony.

MR. MILLER: Do you want me to respond to that?

JUDGE VAN ORT: Go ahead.

MR. MILLER: The one percent productivity adjustment is being applied to salaries, wages and benefits. The pension and OPEB expense is part of that. The one percent productivity adjustment is being applied to an expense that essentially the inquiry is asking hasn't that expense essentially been taken out and not being sought in rates. It applies directly to the testimony on how the one percent productivity adjustment was calculated.

JUDGE VAN ORT: If you are questioning the witness as to whether or not they agree that that is essentially redacted or taken out of the expense, I think we can lead with that. I think that would get to the end.

Mr. Mazza, did you have something else?

MR. MAZZA: To the extent that the witness is speaking about approximate for certain expenses rather than the exact expenses, he should be required to answer whether or not it goes into rates or not.

MR. MILLER: That's an argument, Your Honor, but we are talking about facts here.

JUDGE VAN ORT: Mr. Miller, I think we can allow you a little bit more latitude. I think we pretty much got the point here and your exhibit I think it indicative of that. Your arguments are obvious in brief as to what that exhibit purports to show. I think we can close it out. If the witness can provide any more amplification for that, fine, but I think we need to get to a conclusion on this.

MR. MILLER: As long as Your Honors got the point, I guess there is no point in beating a dead horse. We have nothing further, Your Honors.

MR. MAZZA: Your Honors, may we request redirect.

JUDGE VAN ORT: Yes.

MR. MAZZA: May we have an opportunity to confer.

JUDGE VAN ORT: Yes. How much time do you need?

MR. MAZZA: Five minutes. Thank you.

JUDGE PHILLIPS: Off the record.

(Whereupon, a brief recess was taken.)

JUDGE VAN ORT: I think we are ready to resume. Does anyone need the reporter to go back to where we left off?

MR. MAZZA: No, Your Honors. We have no redirect.

JUDGE VAN ORT: Thank you. The panel is excused.

MR. GRIM: Thank you, Your Honors.

MR. POHORECKYJ: Thank you.

JUDGE PHILLIPS: I believe the next on the list will be the PSEG Capital Budget and Rebuttal panel; is that correct?

MR. FAVREAU: Yes.

JUDGE PHILLIPS: Can you please call the witnesses, call your panel.

MR. MILLER: May we go off the record?

JUDGE PHILLIPS: Yes, we are off the record.

(Whereupon, an off-the-record discussion was held.)

JUDGE VAN ORT: If we can go back on the record. My understanding is we are doing the PSEG Transmission Distribution Capital Budget Panel and rebuttal. Is that correct, Mr. Miller?

MR. MILLER: That's correct, Your Honor. As I was explaining to Judge Phillips, perhaps a point of clarification. The original or initially filed Capital Budget testimony involved T&D, IT Business Services and Customer Services. That panel was composed of Mr. Lizanich, who is on the rebuttal panel but also Mr. Lyons, Mr. Walden and Mr. Parikh, each of whom had responsibilities in their area. Mr. Lizanich is most notable for T&D Capital. As we have gone along, the issues have narrowed themselves to those just related to T&D and with specific emphasis on some accounting issues within T&D, so that is why we constituted a different panel for the T&D rebuttal testimony.

So, the rebuttal testimony is the rebuttal testimony of Transmission and Distribution Capital Budget. The direct pre-filed testimony of the Capital Budget Panel we are putting in by affidavit, and then the rebuttal testimony we have panel here live.

EXAMINATION BY.

MR. MILLER:

JUDGE VAN ORT: Thank you. Ladies and Gentlemen, raise your right hand please. Do you swear or affirm that the testimony you are about to give in this proceeding is the truth, the whole truth and nothing but the truth?

MR. DAHL: Yes.

MR. LIZANICH: Yes.

MR. AICHER: Yes.

MS. FIGLIOZZI: Yes.

JUDGE VAN ORT: We keep having to say this because I have to do it myself, when you are answering questions, make sure you pull the microphone to yourself and make sure you hold the button down. You can proceed.

MR. MILLER: I would ask the panel, do you have in front of you a sixteen-page document titled Rebuttal Testimony of Transmission and Distribution Capital Budget Panel?

MR. LIZANICH: Yes, I do.

MR. MILLER: If I were to ask you questions --

JUDGE PHILLIPS: For the court reporter, we are going to just have to identify the individuals at some point. Continue what you were doing and we will do that.

MR. MILLER: If I were to ask you the questions contained in that document, would your answers be set forth therein?

MR. LIZANICH: Yes.

JUDGE VAN ORT: Would each of the panel members going from left to right identify yourself?

MR. DAHL: Kurt Dahl, D-A-H-L.

MR. LIZANICH: Nick Lizanich, L-I-Z-A-N-I-C-H.

MR. AICHER: Rich Aicher, A-I-C-H-E-R.

MS. FIGLIOZZI: Lisa Figliozzi, F-I-G-L-I-O-Z-Z-I.

MR. MILLER: Is the panel also sponsoring exhibits?

MR. LIZANICH: Yes.

MR. MILLER: Those exhibits are identified as Exhibits CBP-REB 1 through 3, correct?

MR. LIZANICH: That is correct.

MS. FIGLIOZZI: Correct.

MR. MILLER: Were the exhibits prepared by you or under your supervision and direction?

MR. LIZANICH: Yes.

MS. FIGLIOZZI: Yes.

MR. MILLER: Your Honors, I ask that the Prepared Rebuttal Testimony of the Transmission and Distribution Capital Budget Panel be copied into the record as if given orally.

JUDGE VAN ORT: Granted. Can we get the exhibit numbers that you have agreed upon for each of those exhibits.

MR. MILLER: REB 1, Your Honor is Exhibit 16. 2 is 17 and 3 is 18.

JUDGE VAN ORT: Thank you.

MR. MILLER: Your Honor, we are going to move all of the exhibits at the end of the proceeding, correct?

JUDGE VAN ORT: Correct, that's what we are doing.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-00262

REBUTTAL TESTIMONY OF TRANSMISSION AND DISTRIBUTION CAPITAL BUDGET PANEL

Date: June 4, 2015

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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Transmission and Distribution ("T&D") Capital Budget Rebuttal Panel (the "Panel").

A. We are Nicholas J. Lizanich, Lisa N. Figliozzi, Richard L. Aicher and Curt J. Dahl.

Q. Have you previously submitted pre-filed testimony in this proceeding?

A. Yes, with the exception of Mr. Dahl, we have all testified as members of other panels that have pre-filed testimony in this proceeding.

Q. Mr. Dahl, please state your full name and business address.

A. My name is Curt J. Dahl. I am employed by PSEG Long Island LLC ("PSEG LI" or the "Company") and my business address is 175 E. Old Country Road, Hicksville, NY 11801.

Q. In what capacity are you employed by the Company?

A. I am employed by the Company as Manager Transmission and Distribution Planning I have been employed by PSEG LI since 2014. Prior to that time, I was employed by National Grid, and its predecessor companies Keyspan and LILCO.

Q. Please summarize your educational background and professional experience.

A. I am responsible for planning the electric distribution, transmission and inter-connected systems on Long Island, forecasting, reliability and for the overall coordination of the various elements that constitute the local power system. I represent PSEG LI on several NPCC, NYTO, NYSRC and NYISO committees and am currently the Vice-Chairman of the New York State Reliability Council Executive Committee. I have over 28 years of professional experience in electric system planning on Long Island including approximately 25 years of supervisory experience.

As Manager of Generation Planning I was involved in resource adequacy and market power issues, the development of emissions compliance strategies and negotiations of energy and capacity agreements. I have also worked in the Transmission and Distribution Planning groups where I was responsible for developing capital expansion plans for the Long Island power system. I hold a Master's degree of Science in Electrical Engineering from Polytechnic Institute of New York, a Masters of Business Administration from Hofstra University and a Bachelor's degree in Electrical Engineering from Polytechnic Institute of New York. I am a Registered Professional Engineer in the State of New York.

Q. Have you ever testified before?

A. Yes, in various Article VII and Article X proceedings associated with the siting of new transmission and generation facilities. I have also testified at FERC on behalf of LIPA and the New York State Reliability Council on resource adequacy issues.

Q. What is the purpose of the Panel's rebuttal testimony?

A. We will address the testimony of the DPS Staff's T&D (Transmission and Distribution) Capital Expenditures Panel ("Panel") with respect to certain recommendations and capital expenditure reductions they have made. Specifically, we will address the propriety of DPS Staff's complete elimination of any "loading factors" from the capital expenditures, and we will then address DPS Staff's various recommendations and specific project disallowances from the 2016-2018 capital budgets that PSEG LI prepared.

II. DISALLOWANCE OF PENSION/OPEB, A&G "LOADING FACTORS"

Q. What is the most significant difference between the capital budgets that PSEG LI prepared and those that DPS Staff has recommended?

A. The most significant difference is that Staff excluded "loading factors," applicable to the various capital projects. Staff's testimony at page 20 starting at line 1, states that "Because of our inability to determine how the loaders were developed and the unusual method of how it was applied, we recommend that the amount presented in PSEG LI response to IR DPS-CBP-0372 should be 'unloaded' for A&G and Pensions/OPEB, using the percentages we just stated." The DPS Staff Panel "recommends" using a so-called "macro level approach to setting the capital budget, as opposed to our individual project adjustments" which seems to be based on removing the loading factors.

Q. What is the consequence of the DPS Staff's recommendations?

A. DPS Staff has recommended total capital budgets of approximately $314 million, $289 million, and $304 million for 2016-2018, respectively. This equates to total negative adjustments of $36.4 million, $81.9 million, and $66.7 million for the capital budgets in 2016-2018, respectively, when compared to the original budget levels in PSEG LI's Exhibit CBP-2. Other than DPS Staff's recommendation to remove $13 million of the proposed cost for 2018 associated with the Old Bethpage substation project and a few more minor proposed adjustments, the majority of the adjustment that DPS Staff has made to the capital budgets relate to DPS Staff's loading factor adjustment.

Q. Is it appropriate to remove the loading factors?

A. No. "Loading factors" are not simply costs that can be wished away. For example, one component of loading factors is the benefit costs associated with wages and salaries. This includes, but is not limited to, pension costs, post-retirement benefits, payroll taxes, workers compensation costs, and the like. Loading factors also include such things as fleet costs, which are allocated to various capital projects, as well as to O&M and storm costs. DPS Staff recognizes (at p. 19) that "capital projects normally account for A&G and Pensions/OPEBs." An adjustment that removes all such expenses is inconsistent with the norm. It is also inconsistent with the reality that loading factors are an unavoidable cost of everyday utility work.

Q. If the loading costs are eliminated from the capital budgets, as DPS Staff suggests they should be, are the costs avoided?

A. No. As we stated above, loading factors are real costs that cannot be avoided. In the case of employee labor costs, it would make no sense to allocate the cost of wages and salaries to a capital project while ignoring the fringe costs associated with those salaries. To do so would leave those costs unrecovered in rates. The costs of PSEG LI's employee workforce are allocated largely to three "buckets" – O&M, capital, and storms. If some of these costs are not properly allocated to capital as DPS Staff has refused to do here, the costs must be assigned to either O&M or storms. Another example of costs that are allocated as "loading factors" to capital, are fleet costs. These are, for example, the cost of vehicle leases, gasoline, payroll, and the like. If, for example, a new transformer is installed on a pole, the cost of the transformer is billed to capital. It would make no sense, however, to ignore the allocated fleet costs that are necessary for the bucket truck required to transport and install that transformer. Yet, that is exactly what occurs if loading costs are eliminated as the DPS Staff's adjustment would do. These are real costs that will be incurred and should be properly accounted for in the capital budget.

Q. Is there another reason why loading factors cannot be ignored?

A. Yes. These labor and loading costs are pass-through costs to LIPA under the OSA. Consequently, the costs would still be billed to LIPA and collected pursuant to the OSA. The elimination of these loading costs from projected capital spending does not mean that the costs are eliminated. The alternative to loading these unavoidable costs to their associated capital projects is to add the costs to the O&M budget, which would only serve to increase the revenue requirement by recovering those costs in the year incurred rather than over the life of the associated capital projects. This would require an upward adjustment to O&M equal to DPS Staff's reduction to the annual capital budgets and an associated increase in the revenue requirement equal to the eliminated loading factors .

Q. DPS Staff has stated it had difficulties determining the derivation of the loading factors. Did the capital budgets originally filed in this proceeding use a blanket loading factor?

A. Yes, detailed loading factors were not provided at the time of the filing because that information was not then available in the form and detail it is today. The filing, however, did include a loading factor but it was a less detailed approach. At the time, PSEG LI was in the process of implementing its new SAP accounting platform and, until that process was complete, could not budget in SAP.

Q. How was that process conducted?

A. The capital budget was developed initially in total, based on the transmission and distribution ("T&D") history for labor, material, contractors, and benefits. The total capital budget at this level of detail was provided in the document "rate case base data deck.xlsx" that was submitted via email to the DPS Staff on January 29, 2015. The additional workpapers for the A&G and OPEBs loadings were provided in IR DPS-CBP-0288(b) on March 23, 2015. In addition, PSEG LI also held a teleconference with the DPS Staff to describe the capital budget process that led to the capital budget submittal, including application of a general 14.3% manual adjustment loading factor to each of the projects presented in the T&D capital budget.

Q. In light of the developments that took place since the originally filed capital budgets, has the "loading factor" for these capital projects been clarified?

A. Yes, we have been able to cross check the initial "gross loading" approach with a project by project loading approach for 2015. We have explained the rationale for our original capital budget presentation; it was constrained by the timing of the rate plan filing and the capital process defined by the OSA, as well as the transition of both systems and personnel from National Grid. Consequently, the original capital project presentation by PSEG LI showed each project in excel spreadsheet form with a 14.3% fixed loading amount, as opposed to identifying the added actuarial and A&G overhead cost. Although not available at the time of the filing, additional project details are now available for 2015.

Q. Is the loading information that DPS Staff eliminated now available in the capital budgets?

A. Yes, but only for the calendar year 2015. As of March 2015, PSEG LI had inputted the 2015 capital budget into its recently converted SAP system, by project. This required reviewing resources with the project managers, balancing labor for each department between capital, O&M, storms, and FEMA, running loadings, and making multiple edits to tie back to the LIPA Board-approved levels for the projects. What is significant is the fact that the results differ only slightly from the amounts originally estimated. The OPEB loading amount, for example is $27.3 million versus the forecast of $27.9 million and the A&G loadings amount is $23.2 million versus the forecast of $21.7 million. This information is contained in Exhibit___(CBP-REB-1). Because LIPA's overall capital projects change significantly from year to year as a result of many unpredictable conditions (such as resource planning, permits, legislation, staffing changes, benefit plan changes and so forth), it would not be appropriate to continuously balance budget details for projects that may never come to fruition. Consequently and because LIPA only approves the coming year's capital budget in late December, PSEG LI budgets only one year of capital in SAP in detail. More precise information as to labor and loading factors are available only after the capital and O&M budgets are complete and approved. All calendar years after the coming year are estimated off-line and without project by project labor and non-labor details.

Q. The DPS Staff also suggested an alternative reason for removing the loadings, i.e., that the budgets with the loadings removed are more reasonable because they are in line with historical budget information. Is this a valid basis for removing the loadings entirely?

A. It is not a valid basis for removing the loadings, which are a necessary element for capital projects. The fact that the forecasted budgets are higher than past budgets is no reason to reject more recent budgets. First, the mere passage of time, with the attendant inflation, would make current budgets higher than those of the past. Second, the DPS Staff (at p. 12) has explicitly agreed that the methodology PSEG LI uses to establish the capital budgets is reasonable, similar to that used by other utilities, and balances the overall funding requirement:

> We found that PSEG LI's process to identify and prioritize projects to be included in the budget is reasonable and similar to other utilities in the state. Projects are proposed based on mandates, loading forecasts, or reliability concerns, and prioritized based on need and risk analysis to help identify which projects would be best to undertake and at what overall cost. Once all projects are ranked, PSEG LI develops a list of projects to be undertaken, beginning with the higher priority ones, while balancing the overall funding requirement.

If the DPS Staff concedes that the process by which projects are scored for risk and prioritized is acceptable, then it makes no sense to reject the results of that process, i.e., the resulting capital budgets.

Finally, the DPS Staff acknowledges (at p. 13) that the budget is approved by the PSEG LI "Utility Review Board, or URB, before it is presented to the LIPA Board of Trustees for final approval in December." Review by the LIPA Board of Trustees adds an additional level of scrutiny that is not even present for the IOUs in the state.

The capital budgets were developed by PSEG LI using a process that the DPS Staff concedes is “based on mandates, loading forecasts, or reliability concerns, and prioritized based on need and risk analysis to help identify which projects would be best to undertake and at what overall cost.” To recognize the labor required by those projects, but ignore the associated fringe benefits, such as pensions, payroll taxes, and workers compensation costs is simply insupportable. So, too, is ignoring the other components of the loading factor such as fleet costs and allocated labor. The loadings calculation is correct and DPS Staff’s refusal to recognize any loading factors whatsoever is, as DPS Staff itself recognizes, not realistic.

III. NEW BUSINESS ACCOUNTS SPENDING

Q. Starting at page 22 of their testimony, DPS Staff makes recommendations regarding the funding of New Business Blanket accounts. Specifically, DPS Staff recommends (pp. 22-23) “not using 2013 data and 2014 actual expenditures in the calculation” but instead “averaging actual expenditures from 2010 through 2012 and the 2014 budget.” This produces a forecast of $13.26 million that DPS Staff would escalate by 3% percent annually, producing forecasts of $13.66 million, $14.07 million and $14.49 million for 2016 through 2018, respectively. Is this a reduction in funding for New Business accounts?

A. Yes, in its testimony Staff calculated that this produces downward adjustments of $1.83 million, $1.88 million, and $1.94 million for 2016-2018, respectively.

Q. Do you agree with DPS Staff’s methodology?

A. Yes, they propose to eliminate 2013 actuals to remove the effect of Superstorm Sandy and we agree this is reasonable.

Q. Do you agree with the calculated levels of adjustments to the New Business spending?

A. No. The values appear to have been miscalculated. The New Business budgets are described by reference categories B3.1-B3.4 and are shown in the chart below. Excluding 2013 in accordance with the DPS Staff's recommendation results in an average of the 2010-2012 actual spending and the 2014 budget of $13,815,897.

PJD Reference		**2010 Actual $s**	**2011 Actual $s**	**2012 Actual $s**	**2013**	**2014 Budget $s**
B3.1	New Business	$15,700,000	$15,400,000	$17,000,000		$17,800,000
B3.1	New Business Reimbursements	-$6,100,000	-$4,500,000	-$5,400,000		-$5,300,000
B3.2	CIPUD	$955,812	$641,253	$424,681		$200,000
B3.3	URD	$1,676,238	$1,932,680	$1,659,171		$2,200,000
B3.4	URD Services	$284,804	$298,062	$390,886		
	Total Spending (2010 - 2012) & Total Budget (2014)	$12,516,855	$13,771,995	$14,074,738		$14,900,000

Applying the three percent escalation factor adopted by DPS Staff to the corrected average of $13,815,897 produces the following:

Escalation to 2016 (3% for 2 years)	$14,657,285
Escalation to 2017 (3%)	$15,097,003
Escalation to 2018 (3%)	$15,549,913

Q. Should these funding levels be substituted for the New Business Blanket Funding levels recommended by DPS Staff?

A. Yes, they should.

IV. BLANKET CATEGORIES AND BLANKET PROJECTS

Q. DPS Staff also raises "concerns" (at p. 15) about blanket accounts being based on aggregate amounts of projects having individual costs of less than $1 million each. DPS Staff recommends that PSEG LI reduce the blanket threshold to $100,000 and provide more "visibility" to projects between $100,000 and $1,000,000. Please comment on this recommendation.

A. Blanket Categories are made up of Blanket Projects, which are projects that are routine in nature, are typically cost per unit based, and are at a dollar value less than $1,000,000. It is not necessary or cost effective to manage a $100,000 project at the URB level the same as a $1,000,000 project and Staff suggestion to provide more "visibility" to these projects is not necessary. Although these small routine projects are grouped together under a Blanket Category, they receive similar attention and tracking as a specific project. Blanket Projects are assigned to Project Managers or the Operating managers for the region and each blanket project is on the workplan to ensure timely engineering and design to complete the project on time. Also, each blanket project has it is own budget and it is tracked and reviewed for variance. Each blanket project is discussed during workplan and clearance meetings to make sure the necessary labor, material, permits and clearances are available to perform the work.

V. MULTIPLE INTERRUPTION SUB-BLANKET RESPONSE

Q. Starting on pages 25 and 26 the DPS Staff discusses Multiple Interruptions blankets, specifically the Multiple Customer Outage ("MCO") sub-program, citing a supposed "unexpected budget increase in 2018," and recommends the use of a "historical spending average for years 2009-2013" of $5.1 million be used for 2018. Do you agree with this adjustment?

A. No. The DPS Staff's adjustment fails to recognize that the funding level increase for 2018 is completely offset by reduced budgets of $3,090,000 and $4,455,780 for this activity in 2016 and 2017, respectively; taken together, these 2016-2017 budget figures are below the historical average 2011-2015 spending level of $5,664,000 by a cumulative amount of $3,782,220 (see chart below). The reason for this funding approach is to allow FEMA-funded work (which will wind down during 2017 into 2018) to address mainline caused outages affecting MCO customers. The reduction in mainline outages addressed though FEMA funding will remove a variable from the program targeting MCO customers. The multiple interruption program targets smaller areas of abnormally high outage frequencies. It is a high value, targeted program aimed at improving customer satisfaction and quality of life. This shifting of budget dollars to 2018 will enable PSEG LI to surgically address these pockets of poor reliability which will become more apparent as mainline outages are reduced. Therefore, the original funding level identified in 2018 is well-supported and should not be reduced.

Multiple Interruption Historical Spend Rate:

2015	**2014**	**2013**	**2012**	**2011**
$3,000,000	$6,980,000	$7,500,000	$5,040,000	$5,800,000

Average Spend 2011 through 2015: $5,664,000

Requested Budget:

2016	**2017**	**2018**
$3,090,000	$4,455,780	$8,558,045

Average Spend 2016 through 2018: $5,367,942
Amount Below Average 5-Year Funding Level: $296,058

VI. <u>OLD BETHPAGE SUBSTATION</u>

Q. Starting at page 41 DPS Staff discusses the need for the proposed new Ruland Road to Plainview transmission line and Old Bethpage substation. Specifically,

at page 42, the testimony states: "We further recommend that the 2018 proposed budget be reduced by $13 million, given the uncertainty surrounding this project. Should the situation develop where the substation needs to be built, PSEG LI should re-prioritize its 2018 budget to accommodate this project." Does PSEG-LI agree with this recommendation?

A. No. Given the construction lead time and the demonstrated need for the project, it would be too risky not to include funding for construction in the budget.

Q. Have any events since the filing of the Company's pre-filed direct testimony occurred that would also support this position?

A. Yes. The Old Bethpage Substation project is being proposed to address future load additions in the area that include large residential and commercial developments with a total estimate load of 9-16 MW. As reported in a recent Newsday article on May 13, 2015, Exhibit___(CBP-REB-2), the Town of Oyster Bay approved a developer's plan to proceed with one of those projects, a development of 750 homes and commercial retail space. The additional load introduced by this new development further requires inclusion of the project in the capital plans to provide the electrical needs.

Q. DPS Staff indicated that PSEG LI could "re-prioritize the budget to accommodate the project" if it were to proceed. Do you agree with this approach?

A. No. DPS Staff's approach of re-prioritizing the budget in 2018 to meet needs just means that another project would have to be deferred or eliminated, putting other projects and customers served at risk.

Q. What is your recommendation for the Old Bethpage project funding?

A. Due to the latest information and risk to other projects, PSEG LI recommends the continued inclusion of the entire $13.8 million as part of the 2018 budget.

VII. THE URB PROCESS

Q. At page 13, Staff discusses the Panel's opinion concerning the role of the Utility Review Board in the budget process. Specifically Staff challenges the scope of the information presented to the URB, including data on actual spending to date when a change of funding is requested, and variance reporting. Are these claims accurate?

A. No. Specific project funding requests submitted to URB go through a phased funding approach. Prior year history on funding approvals is included in the documents provided to the URB. Actual YTD spending is identified during the monthly capital project budget variance review. Project Managers are required to go back to URB to release additional funding as more details are developed.

Q. On page 14, DPS Staff discusses the Panel's opinion regarding other concerns with the information presented to the URB, specifically the level of detail provided on major investments and degree of visibility into what the funds will be spent on for these large projects. Do you agree with these characterizations?

A. No. URB documentation provides scope, cash flow and approved funding levels of a project. Depending on the phased level of estimation and funding approval by the URB to commence work, the initial order of magnitude estimate based on a one line drawing is prepared. As engineering work commences, detailed work schedules, drawings and more detailed estimates are established in the life cycle for each project and can be requested by the URB. Estimates with cash flow by year against the base budget are included in the URB documents. A Risk and Contingency (R&C) is added to the base estimate depending on the level of estimate. DPS Staff's criticism fails to recognize that R&C dollars cannot be spent unless requested and approved by URB, thereby providing the very visibility that DPS Staff claims is absent.

VIII. CITY OF NEW YORK

Q. Starting on page 13 of the Marczewski testimony the concept of a Collaborative to develop a comprehensive storm hardening plan is proposed, including projections of sea level rise, flood risk and other climatic variables. On Page 15-16, Marczewski proposes LIPA retain a consultant to perform a study on climate vulnerability and associated modeling. Marczewski also envisions that the LIPA study should be updated thereafter on an ongoing basis. Lastly, Marczewski states that PSEG LI should "begin soliciting external and contractor and other resources that will be needed to implement expanded storm hardening program" and that "the collaborative should commence as soon as possible." Do you have any concerns regarding this proposal?

A. Yes. PSEG LI has already conducted studies covering many aspects of the work proposed by City witnesses Marczewski and Horton, including extreme events, sea level rise and surge flooding, performed associated modelling, and has incorporated results into system improvements (e.g., see CITY-0002, CITY-0041, CITY-0043, and CITY-0060). As outlined in CITY-0043, PSEG LI has already incorporated climatic variables into design standards, including 130 mph standards for new transmission and critical distribution infrastructure and design elevations for critical equipment, specifically the higher of the 1-in-100 years plus 2 feet or the 1-in-500 years flood level elevations. Moreover, current PSEG LI storm hardening activities are focused on implementation of a massive three-year $730 million storm hardening program which must follow rigid FEMA design requirements to qualify for funding and fulfil contractual requirements of the LIPA-PSEG LI Operations Services Agreement. It is unclear how the Collaborative concept comports with these obligations. Further, procurement of "external and contractor and other resources" which City witness Marczewski seeks will require significant additional funding and internal resources to support. It is not reasonable to expect that PSEG LI would agree to participate without a better understanding the ratepayer costs and benefits, scope of the proposed Collaborative and impact on existing storm hardening commitments. PSEG LI, however, would be pleased to meet with the City to review their insights and PSEG LI's storm hardening efforts.

Q. Does this conclude your rebuttal testimony?

A. Yes, at this time.

JUDGE VAN ORT: We have rebuttal listed from a DPS stamp in New York City. Does anyone have a preference as to going first.

MR. FAVREAU: I believe we agreed that New York City would go first, Your Honor.

JUDGE VAN ORT: Mr. Goodman or Mr. Loughney? Who is taking charge?

MR. GOODMAN: Yes, Your Honor. Thank you.

EXAMINATION BY

MR. GOODMAN:

MR. GOODMAN: Good afternoon, Panel. My name is Jay Goodman. I am an attorney for the City of New York. I have a few questions for you this afternoon regarding storm hardening and resiliency. Just to be clear at the outset, when I refer to storm hardening, it covers both concepts; storm hardening and resiliency.

To make sure we understand each other when we are discussing this, if I were to explain that storm hardening refers to capital investments that allow the transmission and distribution system to withstand the impact of severe weather with fewer outages and also improve utilities' ability to restore service following a weather-related outage, that that is the meaning of storm hardening resiliency; do you agree?

MR. LIZANICH: Yes.

MR. GOODMAN: Thank you. Hurricane Sandy caused widespread damage to the utility infrastructure through the service territory, correct?

MR. LIZANICH: Yes, it did.

MR. GOODMAN: Do you agree that the distribution of that damage throughout the service territory related in part to a combination of variables including storm size, storm trajectory, wind speed, amount of rain, et cetera, timing of landfall, et cetera?

MR. LIZANICH: Yes.

MR. GOODMAN: A similar coastal storm could result in a different distribution of damage because those variables could be different; different trajectory, timing of landfall, strength of storm, et cetera, correct?

MR. LIZANICH: That's correct. The length of the storm, the direction of the storm, the path of the storm, all those would be variables that would dictate damage to be different for each of those occurrence.

MR. GOODMAN: Even if a storm comparable to Hurricane Sandy were to impact the service territory again, you could see a different group of assets, maybe some overlaps but also different assets, being damaged that were not damaged by Hurricane Sandy?

MR. LIZANICH: It's possible to have difference but there would be a lot of common facilities that would be damage because of the strength of those facilities, and their ability to withstand is a criteria that would determine whether a storm hitting Montauk would have the same damage and effects as a storm hitting the Rockaways.

MR. GOODMAN: Would the panel agree that observation of historic data and computer modeling of future climate conditions have led to the conclusion that sea level is rising?

MR. LIZANICH: We had a study performed by WorleyParsons a world-renown expert on flooding who did advise us of that and that was subsequently built into the recommendations. So, yes, we are aware of a sea level rising.

MR. GOODMAN: The WorleyParsons reports you referred to were provided to the City in response to its discovery requests, 33 and 36, correct?

MR. LIZANICH: I don't remember the exact numbers but, yes, they were provided as part of the testimony.

MR. GOODMAN: Those climate change -- excuse me. Those sea level rise projections provided by WorleyParsons provided the basis for equipment elevation projects that the company is conducting; is that correct?

MR. LIZANICH: That was one consideration that was used in the determination of recommendations for rise of equipment. Yes, that was one recommendation -- I'm sorry, one consideration.

MR. GOODMAN: I understand but I want to make sure. My question may have been confusing. Taking a step back, as part of your storm hardening initiative, equipment identified as being at risk for damage from flooding would be elevated to be above a projected flood level, correct?

MR. LIZANICH: Yes. The results of the study and the path we took forward was to elevate equipment to be out of harm's way. We had a criteria established as recommended by WorleyParsons that was a 100-year storm plus two feet or a 500-year level storm and to be protected from those levels of floods.

MR. GOODMAN: Would the panel agree that the analysis conducted by WorleyParsons should be updated or replaced from time to time?

MR. LIZANICH: The study that was done by WorleyParsons included a couples of facets. One, it including their experience in the industry; not only in the utility industry but in the industry in general because they obviously do flood analysis for state agencies, governments as well as in private industry including utilities. But they also as part of our scope we did a cursory look.

They did a sampling of fifty utilities so they developed a best practice for us to follow, so that was the basis of the analysis performed and the actions we took. Should it be updated over time, there is nothing wrong with updating. Maybe the conditions change. Maybe if better data became available, absolutely. It could be something that could be modified over time.

MR. GOODMAN: Does the company plan to update those studies?

MR. LIZANICH: At this point in time given that the study is only two years old, we feel very confident that the study is still current.

MR. GOODMAN: So the panel is not aware of any advancement in climate science, if you will, that potentially would alter the outcome of WorleyParsons analysis?

MR. LIZANICH: Actually, the climate effects, sea level rise, was one of the lengthy discussions we had with WorleyParsons. As they advised us, there are numerous studies in the industry that talk about various level of sea level rise. They digested that for us and gave us a recommended sea level rise that we subsequently follow as part of the recommendation.

MR. GOODMAN: A short follow-up on your response from a moment ago. You said you believe the WorleyParsons report still is current, but I believe you agree it should be updated from time to time.

Sitting here today, does the panel have an opinion as to how frequently those analyses should be revised?

MR. LIZANICH: Let me be clear, I am not a flood expert. But from the lessons that I have learned, from the reports I have read and from the advice and guidance that I have been given by our hired firm WorleyParsons, sea level rise is something that could be impactful. You are talking about an eight inch -- some level of rise over some period of time. So, if studies were to be found to be advising us that there should be a change, then our standards would change and going forward we would then apply a new standard similar to the way we changed our standards post Sandy.

MR. GOODMAN: I believe you said the extent to which you elevate equipment above some design flood level is based in part upon the projection of sea level rise is one consideration. Another consideration is looking at available flood maps; is that correct?

MR. LIZANICH: Where those flood maps are available, yes.

MR. GOODMAN: As new flood maps become available, do you simply substitute the new maps on a prospective basis? In other words, for the next project you do you might have a different design standard based on new information from the updated flood map?

MR. LIZANICH: The FEMA flood maps get revised on a periodic basis. I'm not aware of them being updated on a routine basis. I can tell you that in Nassau County we still work with FEMA maps from 2009. That's the most recent version. I can tell you in Queens they were updated post Sandy.

There is really only one consideration to doing a flood analysis in determining what level of rise or design you should plan based upon that because obviously the Nassau County maps may be out of date compared to what we experienced with Sandy.

MR. GOODMAN: Am I correct that the panel is aware that the City has recommended that the company commence a collaborative process to discuss the storm hardening program; is that correct?

MR. LIZANICH: I am aware. We did see the information provided.

MR. GOODMAN: The City recommended that that process be modeled on and adapted from the storm hardening and resilience collaborative being administered by Con Edison, correct?

MR. LIZANICH: I am aware of your recommendations, yes.

MR. GOODMAN: Does the panel agree if a collaborative process such as that is implemented, that customers would benefit if new storm hardening investments are identified that would extend asset life?

MR. LIZANICH: I don't think it's a straight yes or no answer. I think it's important to understand how we got to where we are and where we believe we could go going forward. Our process of flood mitigation started back in 2006 with a Navigant study performed, and that was for storm hardening in general which included flood level concerns. Subsequent to Sandy of course we had the issues with the flooding in the stations. We undertook -- we engaged WorleyParsons, as I previously mentioned, to come in and help give us guidance on sea level rise and flood mitigation.

In addition to that, we participate collaboratively in an effort with the Electric Power Research Institute on storm resiliency program in which LIPA was actually one of the leads in that resiliency program to again to collaboratively learn from our fellow utilities. We participate in the EEI, the Edison Electric Institute, where we had numerous discussions in and around flood mitigations specifically. Then, of course, the State of New York and DPS has conducted numerous collaboratives amongst the utilities post Sandy so that we can learn lessons then between them.

Separate from that, we also have engaged with Con Ed directly in understanding their resiliency programs and collaboratively shared with them what we are doing as well. There has been a lot of collaboration, a lot of efforts to get to us to where we are today. Our process was to learn from others where we could because what we experienced in Sandy was somewhat of a first for us.

MR. GOODMAN: With respect to the City's recommendation that there be a collaborative to include stakeholder participation, would you agree that as part of a collaborative if it is implemented that it should include weighing the cost and benefit of various hardening and resiliency measures?

MR. LIZANICH: In any collaborative effort, not just specific to the one you referred to but any collaborative effort, I would expect there be a cost/benefit analysis done to determine what the cost of mitigation is and what the benefits to be expected because at the end of the day our customers would be paying for that. So, yes, I would expect that to be one of the charges for the collaborative effort.

MR. GOODMAN: In its rebuttal testimony, the panel stated that it would be willing to meet with the City to discuss the City's recommendations. The City is definitely interested in such meeting but has a couple of questions. If the City and company were to meet to discuss storm hardening resilience collaborative, would the company object to the Department of Public Service staff being invited to the meeting if they were interested in attending?

MR. LIZANICH: No, not at all.

MR. GOODMAN: Would the company object to NRDC, Natural Resources Defense Council, or some other Stakeholder group being invited if they were also interested in attending a meeting?

MR. LIZANICH: No. I think I can make a generalized statement that from a collaborative perspective bringing stakeholders to the table would be an expected thing. The only thing that we would want to just be cautious of as we move forward would be that there would be value to what we would be getting ourselves engaged in. Remember I had said earlier, all the collaboration that we have done to this point in time plus any collaboration going forward, we would not be adverse if it provided value back to our customers.

I don't know where you currently stand, where they stand and what their goals and objectives of that collaboration would be. If it brought value back to our customers and I could rationalize the cost/benefit of participation versus the value gained, we would not be adverse to that participation.

MR. GOODMAN: You mentioned you had extensive discussions with Con Edison with regard to its storm hardening program and presumably including the collaborative process it is administering. Have you had any feedback from Con Edison?

Now that their collaborative has been ongoing for I believe approximately three years, have you had any feedback from that utility as to the value or I guess productivity, if you will, of that process?

MR. LIZANICH: Con Ed is in a slightly different position relative to Long Island Power Authority in terms of flood zones and major equipment in the flood zone areas. They have a lot of transmissions substations that are in areas that are vulnerable to flooding, so their risks are significant.

In our case, what we have at risk are distribution substations. Obvious customers, in both cases customers are impacted. But we are aware of their program. We are aware what they are doing. We have shared with them our plans. We are aware of how they have elevated, how they have installed barriers at their stations, and we have seen a copy of their latest plan.

MR. GOODMAN: I understand asset vulnerability may be somewhat different between LIPA and Con Edison; however, the collaborative process that is recommended was not tied specifically to whether the predominance of the vulnerability is with respect to the overhead system, the underground system, transmission and distribution, et cetera.

Forgive me if I am putting words in your mouth but if I'm understanding some of the answers correctly, implicit in what you are saying is it acknowledges the current storm hardening program is focused on hardening certain assets against the next hurricane or large tropical storm that may impact the service territory; is that correct?

MR. LIZANICH: Would you repeat that?

MR. GOODMAN: Sure. It was a convoluted question. I admit it. I believe implicit in some of the answers is basically you discuss talking around the fact that the PSEG storm hardening program is designed to harden certain assets against the next large tropical storm or category three hurricane that may impact the service territory; is that correct?

MR. LIZANICH: Let me be clear. Our storm hardening program addresses multiple facets. It addresses flooding and hence the elevation of stations at risk. We had some ten substations experience significant flood damage associated with Sandy. It addresses wind speeds. We have for the last nine years been undertaking an effort to harden our substations to withstand wind speeds 130 miles an hour which is category three hurricane.

We have taken steps in the last nine years since the storm hardening plan was first developed to strengthen transmission lines such that anything new being built or being rebuilt would be withstanding 130 mile an hour wind speeds. These are across the entire island. This is not just something focused on a specific area near the coastal waters. It is across the entire service territory.

So, our storm hardening plan includes many facets directed towards wind speed, ice, rain and flooding as being one of those aspects.

MR. GOODMAN: Adding value, as you said, you expressed a concern that the collaborative process be something that add value. Except that the collaborative can identify additional areas of storm hardening investment that currently aren't being covered.

Would you agree that that would provide value?

MR. LIZANICH: Let me be clear. Our interest would be in learning as much as we can learn about hardening for the sake of being able to provide our customers with more reliable service. We have come a long way in the last several years in terms of our knowledge based on hardening, our knowledge based on flooding, our knowledge based on how to deal with hardening the system. The FEMA grants being one example of the investments that we make. We are making 50 million dollar investments in the Rockaways now to upgrade our substations of which FEMA is covering a portion of the fees. The rest being born by LIPA. We are making significant investments.

So, inasmuch as a collaborative would help us learn more, would help us provide a more comprehensive look at hardening across the grid beyond what we are already doing, we would be interested in that. Again, it would be a basis that as long as it provided us value and we can see value to our customers, it would be worth the investment for our customers for us to make. If the collaborative brought that result to the table, then we would be very interested in participating.

MR. GOODMAN: Was the panel present earlier today when I asked a few questions of the LIPA Overview Panel?

MR. LIZANICH: Yes, I was here.

MR. GOODMAN: Mr. Lizanich, did you hear me ask the LIPA panel whether or not it would oppose the collaborative recommended by the City?

MR. LIZANICH: I do recall that question.

MR. GOODMAN: You did hear then that the LIPA panel said that the facility would support the collaborative; is that correct?

MR. LIZANICH: Absolutely and again --

MR. BROCKS: Objection. I believe the question misstates the testimony.

MR. GOODMAN: I apologize. It was just the last memory. I think the panel may have said they do not oppose the recommended collaborative.

MR. LIZANICH: I would have to ask the court reporter to read back the testimony.

JUDGE VAN ORT: I don't know that we need to go back that far to the testimony. If you just want to state a question as your understanding of it and see if they agree with that. If they do not, that would be the answer.

MR. GOODMAN: Thank you, Panel. Nothing further, Your Honors.

JUDGE VAN ORT: The Department of Public Service Staff reserved time for cross examination?

MR. FAVREAU: Yes, Your Honor. As a preliminary matter, we have marked for identification several IR responses. We provided the other parties notice of these responses on Friday (handing).

MR. GOODMAN: I apologize, Your Honors. Sorry, Mr. Favreau. There were two discovery responses that I hope to mark in evidence. I got caught up in the questions. I can do that after Mr. Favreau's cross examination. I apologize that I forgot to do that before.

JUDGE VAN ORT: Let's finish yours before we go onto the Staff.

MR. GOODMAN: My apologies, Mr. Favreau.

MR. FAVREAU: No problem.

MR. GOODMAN: Two discovery responses (handing).

JUDGE VAN ORT: For everyone's benefit, we are going to identify City exhibit which is identified as discovery as 0102 as Exhibit 104 for identification and City number 0103 is going to be marked as Exhibit 105 for identification. City 0102 will be Exhibit 104.

MR. GOODMAN: Panel, I have handed you your responses to the City's information request, Number 102 and 103. Those were prepared by you or under your supervision; is that correct?

MR. LIZANICH: That's correct.

MR. GOODMAN: Sitting here today, do you have any corrections to make to those, or do you agree the answers are still correct?

MR. LIZANICH: No. I think those answers say exactly what I had reported, which was that we would be willing to talk and evaluate whether there is cost and benefits to the collaborative. I think I paraphrased what was stated.

MR. GOODMAN: Thank you, Panel. Your Honors, I would ask that these be accepted as marked as you just identified them to be marked.

JUDGE VAN ORT: Thank you. We will address the admission of these exhibits as well as the rest at the end. Mr. Favreau.

CROSS EXAMINATION BY

MR. FAVREAU:

MR. FAVREAU: Thank you, Your Honor. As I was saying, we would like to mark our exhibits for identification purposes.

All the parties were aware of it on Friday. They are also on the CD we provided, Your Honors (handing).

JUDGE PHILLIPS: Thank you.

MR. FAVREAU: Panel, if you refer to the document I just gave you, it is a fifty-one page document with an index. These are our responses that particularly pertain only to capital budget.

These responses, were they prepared by you or under your supervision?

MR. LIZANICH: Yes.

MS. FIGLIOZZI: Yes.

JUDGE PHILLIPS: Mr. Favreau, please use your microphone.

MR. FAVREAU: I apologize. Initially -- and we will get back to some of these IR responses in a little while. I want to clarify for the record what exactly the capital budget is, the proposed capital budget is for 2016. I think initially CBP 2 which is 12 on the exhibit list, that was filed in January 2015 initially. Just recently as of Monday there was a revised CBP 2 that was submitted.

Could you tell me in that revised exhibit what the proposed capital budget is for 2016?

MR. LIZANICH: Okay. Let's be specific. The capital budget just for T&D?

MR. FAVREAU: Correct.

MR. LIZANICH: The revised CBP 2 shows the capital budget for 2016 being $360,853,190.

MR. FAVREAU: Thank you. Additionally there was a response that was included in your rebuttal exhibit. I believe it was number 3. The response is number 372.

Can you tell me what the proposed 2016 capital budget is for T&D in that response?

MR. LIZANICH: Give me a second. Response for 37 --

MR. FAVREAU: 372. It is in your rebuttal Exhibit Number 3. To speed up the process if you want, subject to check, it's the same number.

MR. LIZANICH: I'm looking at it here, $360,853,190.

MR. FAVREAU: What was the date of that response at the top; April?

MR. LIZANICH: 372, the date at the top of the document is -- my copy does not have a date. I'm sorry.

MR. FAVREAU: Are you familiar with the Revenue and Ratemaking Panel's testimony, PSEG's panel?

MS. FIGLIOZZI: Yes.

MR. FAVREAU: Are you familiar with the exhibit, in particular Exhibit RRP 1 which I believe is Number 45 on the exhibit list?

MS. FIGLIOZZI: Yes.

MR. FAVREAU: Would you happen to have a copy of that in front of you?

MS. FIGLIOZZI: I do not.

MR. FAVREAU: You do?

MS. FIGLIOZZI: I do not.

MR. FAVREAU: Again, this can subject to check, on page 17 of RRP 1 there is a line that goes down that says projected 2016 capital expenditures. In that they have the total transmission and distribution projects of 648 million and change. Additionally, it has there a line called FEMA-related projects which is 287 million and change.

Would you be willing, subject to check, that the difference between those two numbers is the proposed capital budget number of 360 million?

MS. FIGLIOZZI: Correct.

MR. FAVREAU: Do you know the date of when this RRP exhibit was filed? Was it part of the initial filing?

MS. FIGLIOZZI: Part of our initial filing.

MR. FAVREAU: That was in January, correct?

MS. FIGLIOZZI: Correct, I believe, 29th or 30th.

MR. FAVREAU: Your Exhibit CBP 2, your initial exhibit, do you know what dollar amount that had for 2016?

MS. FIGLIOZZI: I believe it was 316, 316 million -- sorry. It was $352,042,415.

MR. FAVREAU: That is different than the 360 million that is now in the revised exhibit?

MS. FIGLIOZZI: That is correct.

MR. FAVREAU: When you put together a capital expenditure project budget, do you normally go what I will call a top down approach or a bottom up approach?

MR. LIZANICH: So a capital budget is really done both ways. We start bottom up in that we identify the needs of a system, drivers being things like low growth, desire to address reliability concerns, mandated projects, regulatory related, things that we have to do to comply with NERC for example. We assemble up from the bottom all of those projects.

We then have a merge between the need and the risk scoring on those projects to identify what level a risk can we managed and what level a risk can we not live with. That helps us identify what the capital need is. Once that number is identified, then we work backwards from the top down and identify the actually funded projects.

MS. FIGLIOZZI: In addition from a top down basis, during the budget process as the HR organization and the treasury department budget fringe benefits and pensions and OPEBs, it becomes known what that basis is and what kind of loaders will be applied to that detailed capital budget.

MR. FAVREAU: For revised CBP 2, can you tell me what percentage you used for those loaders?

MS. FIGLIOZZI: Excluding our A&G overhead cost, it was approximately 109 percent -- I'm sorry, that includes A&G, 108.6 percent and that is on the basis of labor.

MR. FAVREAU: If I can refer you to the exhibit you have.

This is page 46 of 51. It is your response to REB 475.

Is it correct you have here a percentage being 12.2 percent for 2016 for A&G and OPEB?

MS. FIGLIOZZI: Yes, but that was on a different basis. That was on the basis of the total capital budget versus labor. So using the same comparison we have 14 percent incremental loading factor associated with OPEBs and A&G that had not been on the 2014 budget that was found while we were updating our treasury and fringe benefit budgets. So, that incremental amount of 14 percent does not include the base fringe benefits that were already embedded in the capital budget, so it was an incremental 14 percent on total capital.

During this CBP 475 it was refined to, as you had said, 13.2 percent, 13 percent, 12.2 percent and 13.2 percent.

MR. FAVREAU: So the budget in revised CBP 2, does that include a 14 percent or a 12.2 percent?

MS. FIGLIOZZI: At this point in time, our revenue requirements still contains 14 percent.

MR. FAVREAU: Your capital budget, proposed capital budget, for 2016, one of the components of that budget are these two loading factors; is that correct?

MS. FIGLIOZZI: Which two loading factors.

MR. FAVREAU: The A&G and the OPEB.

MS. FIGLIOZZI: Correct.

MR. FAVREAU: In January your revenue requirement panel had a capital budget for 2016 of 360 million. That included a 14 percent loading factor.

MS. FIGLIOZZI: Correct. Revenue requirements included 360 million. That was inclusive of a 14 percent loading factor.

MR. FAVREAU: If the loading factor for 2016 is 12.2 percent, not the original 14 percent, wouldn't your capital budget for 2016 be approximately 2 percent lower?

MS. FIGLIOZZI: I agree. Without the known impacts of all the other adjustments that come out of all the IRs and the final Ks, we did not update that slight change.

MR. FAVREAU: So it's a revised -- I don't want to really hammer this point but revised CBP 2 which is 360 million should be approximately 2 percent less?

MS. FIGLIOZZI: Correct.

MR. FAVREAU: Thank you. While we are talking about these loading factors, could you generally describe what is meant by an A&G or administration and general project loader?

MS. FIGLIOZZI: An example of a cost that is an A&G loader would be the fixed assets organization. It's an accounting organization that is responsible for closing out capital projects and ensuring that they're depreciated on a timely basis. As well, they're responsible for all the capital reporting.

MR. FAVREAU: Could you also define what is meant by an OPEB project loader?

MS. FIGLIOZZI: OPEBs are other post-retirement benefits other than pensions. It's a FASB accounting rule that came out, and it is a cost that had not been on capital projects in 2014 but were and will continue to be prospectively beginning in 2015.

MR. FAVREAU: Is anyone on the panel familiar with how National Grid, your predecessor service provider, how they determine their project capital expenditures?

MS. FIGLIOZZI: I do not.

MR. AICHER: I do not.

MR. LIZANICH: I do not.

MR. DAHL: No.

MR. FAVREAU: Would it be fair to say then that you do not know whether any of the information from National Grid contained any of these A&G and OPEB loaders?

MS. FIGLIOZZI: That is not true. I am aware of the report that was provided by National Grid and the reporting that National Grid did provide. There were loading rates on capital and we could distinguish the description of those loading rates, what was included in the outcome of capital versus what was not.

MR. FAVREAU: Do you know whether National Grid included the A&G and OPEB loader in its capital expenditure information?

MS. FIGLIOZZI: It is my understanding that they did not.

MR. FAVREAU: That is for what year?

MS. FIGLIOZZI: For 2014, our comparison year to our 2015.

MR. FAVREAU: Does the panel have any knowledge of any prior years other than 2014 on that same question of whether the loaders were included?

MS. FIGLIOZZI: I do not.

MR. FAVREAU: Can you tell me, isn't it correct that OPEB loaders should not be applied to materials when formulating a project cost budget?

MS. FIGLIOZZI: That is correct.

MR. FAVREAU: Isn't it also correct that these OPEB loaders should not be applied to contingencies in their project budget?

MR. LIZANICH: The contingencies added into a project for the uncertainty of the estimate for the project. So, for example, early on before we have definitive cost estimates from construction and from the actual materials that we are going to purchase, we would use estimated costs for those activities and we place a contingency on the numbers because we recognize that there is a margin of error in our estimates being correct.

Inasmuch as a contingency turns into a real number, I believe it should include those OPEBs if the contingency is going to be used because that contingency would be used for labor and those kinds of activities that would naturally carry those loaders.

MS. FIGLIOZZI: Under GAAP accounting we are required to load labor and if contingency involves labor, labor will be loaded.

MR. FAVREAU: Is it correct to apply A&G loaders to materials?

MS. FIGLIOZZI: It is not.

MR. FAVREAU: Is it correct to apply A&G loaders to contingencies?

MR. LIZANICH: Inasmuch as the contingency is used for the purpose of labor, it would be appropriate.

MR. FAVREAU: For revised CBP 2, were either A&G or OPEB loaders applied on a total project cost basis?

MS. FIGLIOZZI: In the presentation, it was presented that way. However, in our system it is only applied on labor. At the time that the exhibits were put together, the detailed labor costs for every individual project had not been available and, hence, that was a presentation purpose only.

MR. FAVREAU: No further cross examination, Your Honors.

JUDGE VAN ORT: Is there any redirect.

MR. MILLER: May I have the same five minutes with the panel?

JUDGE VAN ORT: You may.

(Whereupon, a brief recess was taken.)

JUDGE VAN ORT: Mr. Miller, before you start your redirect, Utility Intervention Uhas one question they just wanted to ask. If you can just allow them to ask their question, and then we will move onto redirect.

MR. ZIMMERMAN: Thank you, Your Honor.

JUDGE PHILLIPS: Can you just identify yourself for the court reporter?

MR. ZIMMERMAN: Yes. I am Mike Zimmerman with the Utility Intervention Unit. Thanks for the opportunity. I just have a very quick question to clarify.

In the context of storm hardening, which systems are you characterizing as transmission versus distribution?

MR. LIZANICH: So, the distribution system that I'm characterizing is our 13,000 volt and our 4,000 volt systems. The transmission that I characterized would be our 23 KV, our 33 KV, our 69, our 138 and our 345. Distribution would be our 13,000 volt and our 4,000 volt system. The transmission that I characterized is our 23,000, 33,000, 69,000, 138,000 and 345,000 volt systems.

MR. ZIMMERMAN: That is it. Thank you.

JUDGE VAN ORT: Mr. Miller.

MR. MILLER: Thank you, Your Honor.

REDIRECT EXAMINATION BY.
MR. MILLER:

MR. MILLER: Panel, PSEG Long Island's labor expenses is composed of wages, salaries and benefits, correct?

MS. FIGLIOZZI: Correct.

MR. MILLER: Is it fair to say that that expense is allocated among three categories. They would be O&M, capital and storms, correct?

MS. FIGLIOZZI: Ultimately, correct.

MR. MILLER: To the extent that that labor expense is allocated away from capital, where would it be allocated to?

MS. FIGLIOZZI: Either to O&M or storms.

MR. MILLER: Is the ratemaking effect of capital different from the ratemaking effect of O&M?

MS. FIGLIOZZI: Yes.

MR. MILLER: If capital dollars are allocated to O&M, is there a one-for-one relationship for the increase of the rate or the revenue requirement for that allocation?

MS. FIGLIOZZI: Yes, there is.

MR. MILLER: That is all we have, Your Honors.

JUDGE VAN ORT: Any further questions?

MR. FAVREAU: One second, Your Honor. There is no further cross examination, Your Honor.

JUDGE VAN ORT: The panel is excused. Thank you all. We are going to recess until 2:15 so we can take a lunch break. You are welcome to leave your materials here. I don't believe the room is locked, so obviously use your own judgment.

(Whereupon, an off-the-record discussion was held.)

JUDGE PHILLIPS: We are going to proceed with entering the rest of the testimony that was identified to be entered by affidavit into the record at this point. What we like to do to try to speed it up is that the order in which the witnesses are listed on the list that we were provided, we will get copies of the affidavits in hard copy. We will mark them sequentially, so let's start with the Falcone affidavit.

MR. BROCKS: Let the record show I presented the judge with the affidavit of Mr. Falcone.

JUDGE PHILLIPS: The affidavit of Tom Falcone has been marked for identification as Exhibit 107. Can you just tell me, is it testimony and exhibits?

MR. BROCKS: Yes, Your Honor. The exhibits are identified as the pre-numbering that is also on the affidavit.

JUDGE PHILLIPS: For the record, can you state is it I believe both the original and rebuttal?

MR. BROCKS: That is correct, Your Honor.

JUDGE PHILLIPS: Again, for the benefit of the court reporter so she knows what is going in where, can you state the number of pages? I will just read from the affidavit.

MR. BROCKS: I got it. Here you go, Your Honor. The Direct Testimony consists of 49 pages plus a title page and also the Exhibit 1. The Rebuttal Testimony consists of 30 pages plus a cover page and also Exhibits 5 through 9.

JUDGE PHILLIPS: The testimony just identified should be copied into the record as though given orally. The exhibits that were referred to have been premarked in accordance with the exhibit list circulated previously by the parties.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan

Matter Number: 15-______

DIRECT TESTIMONY OF

THOMAS FALCONE

LONG ISLAND POWER AUTHORITY

JANUARY 30, 2015

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Thomas Falcone, Chief Financial Officer, Long Island Power Authority (the "Authority"), 333 Earle Ovington Boulevard, Suite 403, Uniondale, New York 11553.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science in Economics from the University of Pennsylvania Wharton School. Professionally, I spent 13 years in investment banking working in municipal and utility finance. In that capacity, I raised approximately $30 billion of capital for many of the largest public power utilities and municipal borrowers in the country. I joined the Authority in January 2014.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony serves several purposes. I present the Authority's approach to establishing its financial revenue requirements using the "public power model." I discuss the Authority's financial policies, which are designed to achieve sound fiscal operating practices at the lowest cost for our customers. I demonstrate how the Authority's financial policies and structure provide real and significant benefits to our customers. And, I describe how the Authority's electric rates are comparable to the region.

Q. WHAT ARE THE AUTHORITY'S OBJECTIVES FOR THE THREE-YEAR RATE PLAN?

A. The Authority has three objectives for the rate plan – first, to establish adequate budgets that maintain high standards of reliability, while improving customer satisfaction and storm response; second, to establish the Authority's requirements to meet its own financial obligations as required by the LIPA Act, the LIPA Reform Act, and the Authority's bond and bank agreements; and third, to keep rates and charges at the lowest level consistent with sound fiscal and operating and practices, also consistent with the LIPA Reform Act.

Q. HOW DO THE AUTHORITY'S RATE PLAN OBJECTIVES BENEFIT CUSTOMERS?

A. The Authority is a public power utility that operates solely for the benefit of its customers. We have no stockholders. This Rate Plan outlines many investments and service quality improvements for our customers. And, the financial policies we propose will lower our borrowing costs, reduce our debt relative to our assets, and ensure our access to capital on reasonable terms, which is essential to providing reliable and safe electric service to our customers.

Unlike an investor-owned utility ("IOU"), the Authority does not generate a rate of return to pay dividends or produce earnings for third-party owners. On the other hand, there are no stockholders to provide incremental sources of funding or bear the cost of unexpected events. All the benefits and all the costs of a public power utility flow to our customers, and so maintaining sound fiscal operating practices are particularly important for our customers in order to protect their interests.

Q. DOES THE AUTHORITY'S STATUS AS A PUBLIC POWER UTILITY PROVIDE BENEFITS TO ITS CUSTOMERS?

A. Yes, there are several benefits from the Authority's status as a publicly-owned utility. The Authority is able to raise debt to fund capital projects in the tax-exempt municipal bond market, which has lower interest costs than are available to IOUs. The Authority also has no third-party shareholders, and so it does not need to generate earnings to pay dividends. The Authority pays no corporate income taxes. Finally, the Authority is eligible for federal grants not given to IOUs to replace and harden storm-damaged facilities. An important example of this benefit is the nearly $1.6 billion of federal grants that the Authority has received over the last five years, which paid for damage to the electric system sustained during Superstorm Sandy, Hurricane Irene, and other recent severe weather events. These grants also included money to fund 90 percent of a $730 million storm hardening program, which will benefit our customers both in terms of resiliency against severe weather events but also day-to-day system reliability. A number of regional IOUs incurred similar storm damage, and are executing similar storm hardening programs, and their customers are paying all of these costs. So there is no doubt that the Authority's status as a public power utility lowers customer bills from what they would be if Long Island were being served by an IOU. We estimate that the Authority's status as a public power utility saves our customers approximately $400 million per year.

Q. WHAT IS THE BASIS FOR THE AUTHORITY'S ESTIMATE THAT BEING A PUBLICLY-OWNED UTILITY SAVES ITS CUSTOMERS APPROXIMATELY $400 MILLION, OR 11% PER YEAR?

A. The Authority's average cost of debt financing is approximately 4.75%, which includes the benefit of being able to sell tax-exempt debt as a municipal utility. The Authority also pays no corporate income taxes and any excess funds are retained and invested in the electric system for the customers' benefit rather than paid out to shareholders. The Authority's approved 2015 Operating Budget includes $365 million for interest payments on an average principal balance of $7.6 billion. By comparison, an investor-owned utility has a cost of capital of closer to 10% on a pre-tax basis and about 7% on an after-tax basis.[1] Our lower cost of capital saves our customers approximately $210 million per year. Additionally, the federal grants to pay for storm restoration and capital projects described above would otherwise have been paid by customers. We estimate that those grants save our customers approximately $190 million per year, for total savings from our municipal utility status of approximately $400 million per year. That $400 million per year estimate is a rough estimate, but provides the right order of magnitude.

[1] See Consolidated Edison Company of New York Electric Case 12-E-0300

That means that residential customers' bills are lower by approximately $17.50 per month or 11 percent of the average customer's bill.

Q. DOES THE AUTHORITY SEEK TO MINIMIZE COSTS BORNE BY CUSTOMERS?

A. Yes, it does. Three areas of focus are financing costs, grants and taxes. In 2013, the Authority was the first municipal utility in the country to refinance a portion of its outstanding debt with triple-A rated securitization bonds, which provided net present value savings of $132 million for our customers and was a key element to the Authority maintaining a delivery rate freeze in 2014 and 2015. The ability to issue triple-A rated securitization bonds was made possible by Part B of the LIPA Reform Act. Going forward, we have identified additional savings to customers that could be achieved by refinancing other Authority bonds with securitization bonds, with anticipated savings of an additional $155 million assumed in the Rate Plan. This minimizes the rate adjustments we need from customers over the next three years. Additional refinancing savings will only be possible with additional legislation. However, the successful implementation of that first round of securitization in 2013 created confidence that securitization is a useful financial tool for a public power utility with the Authority's low credit ratings and high debt levels and that it lowers rates for customers. A bill was introduced as part of the Governor's Budget on January 21, 2015 that would authorize the issuance of up to an additional $2.5 billion of securitization bonds to refinance Authority bonds at a significantly lower cost than the Authority could otherwise achieve. These bonds would be issued by the Utility Debt Securitization Authority ("UDSA"), the separate State Authority that is responsible for refinancing the Authority's debt with securitization bonds. So this refinancing initiative seeks to reduce the cost of our debt.

Q. PLEASE CONTINUE.

A. With the help of Governor Cuomo's administration, the Authority has aggressively pursued grant opportunities, signing $1.4 billion of grant agreements during 2014 alone. The Authority has received $1.6 billion of such grants over the last five years.

Finally, the Authority continues to pursue litigation to reduce the tax burden imposed on customers through over-assessed property taxes (payments-in-lieu of taxes or "PILOTS") on the legacy generating plants on Long Island. Taxes and PILOT payments are approximately 15 percent of our customers' bills,[2] compared to a more typical 4-6 percent for other public power authorities around the country[3] and a weighted average of 10.4 percent for investor-owned utilities in New York (see Table 1). The New York State weighted average is heavily influenced by Consolidated Edison ("ConEd"), where the tax burden is most similar to Long Island at 13.6% of the customer bill. Excluding ConEd, taxes for the other major electric utilities in New York range from 4.5 percent to 9.3 percent with a weighted average of 5.8 percent. That extra burden of 5-10 percent of the customer bill for tax and PILOT payments is a hidden cost to our customers that raises electric rates.

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[2] Authority Approved 2015 Operating Budget

[3] See Fitch Ratings, *U.S. Public Power Peer Study,* June 13, 2014

Table 1: Non-Income Taxes for Major New York Electric Utilities

Utility	2012 Non-Income Taxes as % of Total Revenue	2012 Non-Income Taxes $ Million
Long Island Power Authority	**15.3%**	**$549**
Consolidated Edison	13.6%	1,403
Rochester Gas and Electric	9.3%	68
New York State Electric and Gas	7.4%	105
Orange and Rockland	7.2%	39
Central Hudson Gas & Electric	5.5%	40
National Grid	4.5%	181
New York State Weighted Average (excluding Authority)	**10.4%**	**1,837**
New York State Weighted Average (excluding Authority and ConEdison)	**5.8%**	**433**

Source: NYS DPS, *Financial Statistics of the Major Investor-Owned Utilities in New York State, 2008-2012;* Authority 2015 Operating Budget

Q. WHO IS RESPONSIBLE FOR ESTABLISHING SOUND FISCAL PRACTICES FOR THE AUTHORITY?

A. In accordance with the LIPA Reform Act and the Amended and Restated Operating Services Agreement (“OSA”), the Authority retains the responsibility for financing the business and operations of the electric system, including determining rates and charges, capital markets activities, and communications and reporting to lenders and rating agencies. One of the key roles for the Authority is to establish sound fiscal practices for the purpose of rate setting. PSEG-LI’s responsibility is to put forth operating and capital budgets necessary to operate the system safely and reliably and with a focus on customer satisfaction. They operate the system on the Authority's behalf on a pass-through expense basis. PSEG-LI's financial interest in the electric system is limited to the management fees paid for their services.

Q. DO THE AUTHORITY'S FINANCIAL POLICIES STAND IN ISOLATION FROM ITS RATE SETTING POLICIES?

A. No, for a public power utility, the rate setting policies are directly tied to the financial policies. Public power utilities are ultimately financed by their customers. There are no stockholders to provide capital and cover the risk of poor performance. The Authority can borrow money from the bond markets and banks to finance investments in the electric system but that money must be repaid by customer funds with interest over time. Since the Authority relies on bonds and banks to provide low cost funding, and since customers must pay for higher interest expense if the Authority appears less credit-worthy to these bondholders and banks, customers have a significant interest in the Authority's financial policies. At the same time, customers can gain significant benefits from sound fiscal operations, as the interest rates for highly-rated municipal utilities are much lower than the interest rates charged to less credit worthy utilities, and the interest rates on debt for a municipal utility are much lower than the capital costs for an IOU. Shareholders of IOUs require higher compensation for the risk of poor performance, and their returns are after payment of federal and state corporate income taxes not paid by public utilities and after taxes imposed on investors' dividends and capital gains that are not paid by investors in our tax-exempt municipal bonds.

Q. WHAT IS THE PUBLIC POWER MODEL THAT IS REFERRED TO THROUGHOUT THE RATE PLAN?

A. Public power utilities like the Authority are fundamentally different from the IOUs that are regulated by state public service commissions. This is true in New York and throughout the United States. Regulation of IOUs is designed to ensure that for-profit utilities earn reasonable but not excessive rates of return, maintain reliability and customer service rather than cut such costs in order to boost profits, and that stockholders bear costs and experience losses that are commensurate with the risk that they are compensated for through their equity rate of return. For the Authority, through the LIPA Reform Act and the OSA, and for public power utilities in general, these are not the key considerations in the rate-setting process.

Public power utilities like the Authority have two key considerations when setting rates: (1) will electric rates be sufficient to provide safe and reliable electric service to customers and meet the financial obligations of the utility; and (2) are electric rates set to the lowest possible level balancing the interests of both current and future customers.

From a financial perspective, the same points can be made, albeit with a different focus: (1) will the utility achieve sufficient revenues to ensure payment of all expenses and access to the bond markets and bank loans on reasonable terms; and (2) will the utility achieve an appropriate balance in funding infrastructure investments between customer-funded contributions from electric rates today and debt financing.

The thought process a public utility goes through in creating a financial policy is similar to the logic an individual uses when applying for a mortgage to buy a house. The home buyer knows that they will get a better interest rate if they have a history of making sound financial decisions, an income that supports their mortgage payment and other expenses, and a reasonable down payment on their purchase. With all of those things, the buyer knows they will have access to a number of different lenders for a mortgage and will receive a lower interest rate. Like the borrower that pays their bills on time, maintains a prudent level of debt, and checks their credit score regularly, a utility using the public power model focuses on the key determinants of bond and bank financing and directly addresses the needs of customers by minimizing financing costs over time.

Q. WHAT ARE THE COMPONENTS OF THE PUBLIC POWER MODEL?

A. The public power approach to setting rates defines the utility's revenue requirement as the amount of revenue from customers needed in the year to pay the utility's "out-of-pocket" operating expenses, meet the utility's debt payment obligations, and generate enough "coverage" or excess of revenues over expenses to meet two objectives: (1) provide bondholders and banks with an appropriate degree of confidence that all of the expenses and the debt payments on the bonds and bank financing will be paid (the greater the confidence, the lower the interest rate on debt – just like the homebuyer mentioned earlier who will get a lower interest rate if their income is sufficient to pay all their day-to-day operating expenses plus their mortgage with some room for the unexpected); and (2) provide an appropriate contribution to new capital additions (the equivalent of the down payment on the house mentioned above) in order to manage the utility's ongoing reliance on debt. The good news for customers on these two points is that they are not additive. The same dollars can be used to provide confidence to lenders, and then be used to fund a portion of the annual capital program after the debt service payments have been made.

Q. WHAT ARE THE "OUT-OF-POCKET" OPERATING EXPENSES?

A. Operating expenses are generally considered to be costs that are incurred and paid within the year. These expenses, while essential, provide limited future benefit to customers. The benefit is primarily received in the current period. An example would be fuel costs. However, for financial reporting purposes, there can sometimes be significant differences between when certain expenses are recognized for accounting purposes and when the expense is paid on a cash basis. Pension expenses and amortizations of deferred expenses are the two most obvious examples where operating "expenses" can differ between the regulatory accounting of IOUs and the public power model. Investor-owned utilities tend to recover pension expenses according to an accounting schedule over time, while public power utilities tend to recover such costs in the amounts they use to fund the pension trust. Similarly, regulated utilities will defer some costs until after their public service commission has had a chance to review them in their next rate plan and will amortize those costs for recovery in future years (*e.g.*, pension costs that differ from forecast). Public power utilities tend not to do that. Public power utilities tend to recover expenses in the year they are incurred because that is how the rating agencies, bondholders and banks that provide debt financing look at their financial performance – on a cash flow basis. This also means that public power utilities do not have to borrow money and pay interest expense to finance the deferral of recovery for these expenses, most of which do not provide benefit to future customers. Accordingly, the Authority's proposal to move from a rate setting paradigm loosely based on the IOU model to one based on the public power model will over time lead to less reliance on debt financed deferrals, thereby strengthening the balance sheet and resulting in stronger ratings and a lower cost of borrowing.

Q. DOES THE PUBLIC POWER MODEL ALIGN WITH THE AUTHORITY'S LEGAL AND FINANCIAL FRAMEWORK?

A. Yes. The LIPA Reform Act and LIPA's bond covenants require the Authority to collect revenues sufficient to meet all of its contractual obligations. In the context of the public power model, this aligns with the operating expenses and debt service requirements on the outstanding bonds. The debt service coverage component is not a contractual obligation and falls within the scope of sound fiscal operating policy[4].

Q. WHAT ARE THE ELEMENTS OF A "SOUND FISCAL OPERATING POLICY?"

A. The utility business is highly capital intensive. Each year, the Authority collects from customers all of its current operating expenses but spends more money than it takes in. The balance is spent on capital investments, the majority of which the Authority borrows for in the debt capital markets and with bank lending. These capital investments are for assets like substations, poles, and wires and are necessary to maintain the electric system in sound operating condition. These investments are long-life assets, the equivalent of when one of our customers buys a house. It makes sense for many of our

[4] The Authority's bank agreements have minimum credit ratings and levels of debt service coverage below which is an event of default that results in the early termination of the agreement. This level is below the coverage level that would result in sound fiscal policy. It is a level at which the Authority has already lost access to financing on reasonable terms.

customers to pay for their house over time as the customer enjoys the benefits of that house over time. Likewise, financing our capital projects permits these long-life infrastructure investments to be paid for over a period of time commensurate with when the benefits are realized by our customers. The only alternative would be to recover these costs from customers all in the year they are incurred, which would not be equitable to current customers given the long life of the assets.

In addition to financing new capital investments, the Authority has existing bonds and bank loans, a portion of which come due and need to be refinanced each year. These shorter term bonds and loans provide a lower cost to the Authority than long-term bonds, much like a 10-year adjustable rate mortgage has a lower cost than a 30-year fixed rate mortgage. And, there are also periodically economic opportunities to refinance debt for lower cost, like refinancing a mortgage when interest rates drop. If the Authority is creditworthy, it can take advantage of these opportunities.

So, a sound fiscal policy has to be one where the Authority continues to have access to capital on reasonable terms under a broad range of market conditions.

The Authority needs to be able to borrow funds on reasonable terms to make infrastructure investments that maintain the electric system in sound operating condition and to refinance bonds and bank loans as they become due at a reasonable cost, much like a homeowner that wants to buy a house or refinance a loan at a lower rate needs access to a new mortgage. The PSEG-LI Ratemaking and Revenue Requirements Panel contains a summary of the Authority's projected borrowing needs over the next three years.

Q. IS ACCESS TO CAPITAL ON REASONABLE TERMS THE ONLY FACTOR IN A "SOUND FISCAL OPERATING POLICY?"

A. No, beyond that some utilities have a lower cost of borrowing than others, and credit ratings are a good proxy for borrowing costs over time, much like credit scores are a good proxy for a homebuyer's mortgage rate. Utilities with higher credit ratings will enjoy lower borrowing costs and more robust access to debt and bank financing even in unfavorable market conditions. As there are no shareholders to pay higher debt costs, any higher costs for debt financing are ultimately the customers' cost. So, a sound fiscal policy should be reasonably likely to produce the lowest electric rates for customers over time.

Q. ARE THERE COMPETING NEEDS THAT NEED TO BE BALANCED IN SETTING A "SOUND FISCAL OPERATING POLICY" FOR A PUBLIC POWER UTILITY?

A. All utilities want to provide their customers with reliable service and high customer satisfaction. But for IOUs, management also has to balance the interest of customers with those of shareholders. For a public power utility, management looks only to the best interest of the customers. There is a balancing, but it is a balancing of the customers' short-term interest in lower electric rates today with the customers' long-term interest in safe and reliable service at lower electric rates and debt costs over time. Excessive borrowing places a burden on future customers and results in higher costs today and over time. Financial policies that are not fiscally sound result in lower credit ratings and higher borrowing costs, and therefore higher electric rates.

Q. HOW HAS THE AUTHORITY STUDIED THE ISSUE OF SOUND FISCAL OPERATING POLICY IN ORDER TO DETERMINE ITS REVENUE REQUIREMENT?

A. The Authority has engaged the services of Public Financial Management, Inc. ("PFM") to review the Authority's financial policies with regard to rate setting and revenue requirements. A report by PFM is attached as Exhibit __ (TF-1). The PFM report finds that the Authority has the lowest credit rating among large public power utilities in the United States[5] and high levels of debt relative to assets, and that adoption of the public power model for setting revenue requirements will lead to improved financial performance, lower debt relative to assets, and a better result for customers over time.

Q. WHAT ARE PFM'S QUALIFICATIONS TO MAKE SUCH RECOMMENDATIONS?

A. PFM is the number one ranked financial advisor to public power utilities in the United States. The firm works with approximately 70% of the 50 largest public power issuers, including seven of the ten largest such utilities, and advises on capital markets transactions worth over $50 billion annually. PFM has more relevant experience with public power utilities than the next four ranked firms combined.

Q. WHAT WERE PFM'S RECOMMENDATIONS REGARDING CREDIT RATINGS?

[5] Excluding Puerto Rico Electric Power Authority ("PREPA"), which is currently in a forbearance agreement with its lenders and has limited access to borrowed funds.

A. PFM recommends that the Authority adopt a financial policy to achieve a "mid-A" credit rating over five years. The Authority's peer public power utilities (generally the ten largest such integrated utilities in the United States that provide generation, transmission, and distribution service to a combination of retail, commercial and industrial customers) have an average rating of "low-AA." The lowest rated large public power utility, other than the Authority, is rated "high-A." The ratings on the Authority's electric revenue bonds are several notches below its peers.

Q. WHAT ARE THE AUTHORITY'S CREDIT RATINGS AND WHAT DO THE AGENCIES SAY ABOUT THE AUTHORITY?

A. The Authority's bond ratings were affirmed by the three rating agencies in November 2014 at "Baa1" by Moody's Investor Service ("Moody's"), "A-" by Standard and Poor's Ratings Services ("S&P"), and "A-" by Fitch Ratings ("Fitch"). Each of the agencies also assigned an "outlook" to their credit rating. The outlook indicates the potential direction of the credit rating over the next six months to two years. Moody's assigned a "stable" outlook at their "triple-B" category rating while S&P and Fitch assigned "negative" outlooks at their "low-A" ratings. So the Authority has a "triple-B" category rating from Moody's and the other two rating agencies are indicating their "low-A" ratings could go to the "triple-B" category.

In their November 2014 rating reports, the agencies made positive comments about certain aspects of the Authority's credit but also echoed the sentiments expressed by PFM in their report. For example, Fitch commented that they view "a number of the restructuring initiatives positively" and noted the Authority's "improved power supply mix, affluent well-diversified customer base, and approved rate mechanism to stabilize sizable fuel and purchased power related cash flow" were positives but also noted that "the Authority remains considerably levered with $10.2 billion of debt (including capital leases and securitized bonds) and equity capitalization at just 3.6%. Debt per customer is elevated at $9,173 for fiscal 2013, compared to the "A-" peer median of $3,403." Fitch further noted that "the adoption of rate-setting and financial policies that are supportive of credit quality consistent with the rating would be viewed positively and could stabilize the outlook." The financial policies outlined in the Rate Plan are designed to address the concerns highlighted by the rating agencies.

Q. HOW WOULD HIGHER CREDIT RATINGS BENEFIT THE AUTHORITY'S CUSTOMERS?

A. Higher credit ratings translate directly into lower costs of borrowing and less risk for customers, just as higher credit scores benefit a homebuyer seeking a mortgage in terms of a lower interest rate. Also, a direct result of achieving the higher ratings will be that the Authority will become less reliant on debt over time, and that the ratio of debt to total assets will decline, since such a financial policy would allow the Authority to fund a larger proportion of its capital needs from pay-as-you-go funding, the equivalent of putting a larger down payment on a home.

Higher bond ratings also translate into better access to short term bank lending and borrowing in the capital markets. The Authority relies on access to the commercial paper market and short-term bank loans to smooth out its cash flow requirements during the year and to fund its capital requirements between long-term bond sales. Access to the commercial paper market and bank lending are necessary to smooth out these swings in short-term financing requirements, swings which would otherwise be borne directly by customers, and would result in higher electric rates (to obtain the needed funds or to borrow more costly long-term debt to finance short-term needs). Additionally, the Authority has various contractual obligations with terms directly tied to the Authority's credit ratings. For example, a decline in credit ratings would trigger greater collateral posting under contracts to hedge fuel and purchased power costs and could jeopardize the Authority's ability to maintain such a program to mitigate the effects of volatile commodity costs on customer rates. The potential benefits of higher bond ratings are described further in PFM's report.

Q. HOW WOULD THE AUTHORITY ACHIEVE THE "MID-A" CREDIT RATING TARGET RECOMMENDED BY PFM?

A. The Authority believes it could attain "mid-A" credit ratings within 4-5 years by generating sufficient revenues for a "fixed obligation coverage ratio" of at least 1.45x on Authority debt and 1.25x on both Authority and UDSA debt. Fixed obligations include capitalized leases and other contractual payments that have debt-like fixed costs. The fixed obligation coverage ratio measures the ratio of the cash flow available after the payment of operating expenses to debt and debt-like payments. In our example of the homebuyer, this would be the amount available to make the mortgage payment after payment of food, transportation, utilities, and other day-by-day expenses. A ratio of 1.10x would imply that our homeowner's mortgage payment (or Authority's fixed-obligation payments) is equal to roughly 90% of the cash available after payment of day-to-day expenses each month, which leaves only a small cushion for the unexpected.

A policy of maintaining minimum fixed obligation coverage in each year is both observable and achievable if the Authority adopts the public power model to determine its revenue requirements as proposed in this Rate Plan, rather than target other financial statistics such as net income in setting electric rates. Under the public power model, the utility directly calculates revenue to provide the level of coverage necessary to maintain its target credit ratings. The Authority proposes to phase-in the financial policy by setting increasing minimum coverage ratios in each year of the Rate Plan until the full target is achieved in 2019, as outlined in Table 2.

Table 2: Minimum Fixed Obligation Coverage Ratios

Fixed Obligations	**2016**	**2017**	**2018**	**2019**
Authority Debt + Capitalized Leases	1.20x	1.30x	1.40x	1.45x
Authority Debt + UDSA Debt + Capitalized Leases	1.15x	1.20x	1.25x	1.25x

The minimum coverage ratios are calculated on both Authority-only debt and combined Authority and UDSA bonds because rating agencies and investors calculate the fixed-obligation coverage ratio both ways in making comparisons to other public power utilities. The Authority, through the UDSA, was the first municipal utility to issue securitization debt in 2013 and remains the only such municipal utility to have done so to date. The Authority's projected fixed obligation coverage for the Rate Plan period can be found in PSEG-LI's Ratemaking and Revenue Requirements Panel.

Q. HOW DO THESE COVERAGE LEVELS COMPARE TO RATING AGENCY CRITERIA AND INDUSTRY STANDARDS?

A. The Authority's proposed minimum coverage ratios are below those achieved by the Authority's single-A rated peers. For example, the Moody's rating criteria for public power issuers[6] indicates a fixed charge coverage ratio on combined Authority and UDSA debt of 1.50x to 1.99x for a single-A category rating versus the 1.25x minimum proposed by the Authority. As mentioned earlier, Moody's currently maintains a "triple-B" category rating on the Authority's bonds. In Moody's November 2014 rating report on the Authority, Moody's noted that their rating could rise if "LIPA's fixed obligation charge coverage [on both Authority and UDSA bonds] were to remain above 1.25x" but could decline further into the triple-B category if "fixed obligation charges [on both Authority and UDSA bonds] were to remain below 1.10x." Moody's further estimated that the Authority's 2015 coverage of Authority and UDSA fixed obligations would be above 1.15x. Thus, the Authority's proposed minimum fixed obligation ratio of 1.15x for 2016, if achieved, is consistent with maintaining its credit ratings in the near term. The Authority's proposed minimum fixed charge ratio of 1.25x by 2018, if achieved, is consistent with at least a "low-A" rating based on Moody's comments.

[6] Moody's Rating Service, *U.S. Public Power Electric Utilities with Generation Ownership Exposure*, November 9, 2011.

In their November 2014 report on the Authority's bonds, S&P noted that fixed charge coverage [on both Authority and UDSA debt] was 1.1x in 2008-2011, 1.0x in 2012 and 1.2x in 2013 and their view was that the pre-2013 coverage levels were "thin for the rating," consistent with their negative outlook on the Authority's credit rating. Based on these comments, the Authority's proposed minimum fixed charge ratio on both Authority and UDSA debt of 1.15x for 2016 is low for its current "A-" S&P rating. The improving coverage levels over the Rate Plan are consistent with maintaining the Authority's "A-" rating by S&P but it remains to be seen whether a modest improvement to a 1.25x coverage ratio is sufficient for a "mid-A" S&P rating.

Q. IF THE AUTHORITY'S PROPOSED FIXED OBLIGATION COVERAGE TARGETS ARE LOW FOR A MID-A RATING WHY WILL THE AUTHORITY ACHIEVE SUCH A RATING?

A. One of the benefits of a clear and understandable coverage-based financial policy using the public power model is the greater transparency provided to market participants about the Authority's ratemaking process. In recognition that the Authority's proposed coverage ratios are lower than typical for its desired credit ratings, the Authority also proposes to implement current cost recovery mechanisms, to provide greater confidence to rating agencies, bondholders, and bank lenders that the minimally-necessary coverage targets described previously will be achieved as well as to ensure that current customers are paying the fair cost incurred to provide service and not deferring these costs into future periods. We believe the combination of greater transparency in the rate setting process, including minimum coverage-based financial targets, and greater certainty of achieving those targets through current cost recovery mechanisms, are likely to be sufficient to achieve "mid-A" credit ratings despite our lower than average proposed targets for the desired credit ratings. The alternative would be to target higher coverage ratios, leaving greater room for the unexpected, so our proposed policy is consistent with setting rates at the lowest level consistent with sound fiscal operating practices.

Q. IS THE FIXED OBLIGATION COVERAGE RATIO THE ONLY IMPORTANT FINANCIAL RATIO TO ACHIEVE MID-A RATINGS?

A. No, the PFM Report describes a number of financial metrics that are monitored by the rating agencies and investors, but coverage of fixed obligations is the most followed and the ratio used first by analysts in reaching credit judgments.

In making their recommendation, PFM looked at the impact of the proposed coverage ratios, if achieved, on other financial metrics and concluded that these targets would likely lead to an acceptable range for these other credit metrics for a "mid-A" rating within five years.

Q. WILL THE PROPOSED FINANCIAL POLICIES REDUCE THE AUTHORITY'S LEVEL OF DEBT?

A. The Authority's debt level has been a focus of many stakeholders over time. Uniquely, the Authority started out in 1998 entirely debt funded, as the takeover of the Long Island Lighting Company ("LILCO") was funded entirely by bonds. But rather than evaluate the absolute dollar value of debt, most credit analysts instead look at certain financial metrics such as the amount of debt relative to assets or the amount of debt relative to productive assets (excluding intangible assets like the Authority's Acquisition Adjustment, which was the amount paid for LILCO in excess of book value). For example, a utility that is making productive infrastructure investments to maintain and improve the electric system for its customers may finance part of that investment with debt, causing the dollar value of debt to increase. But the utility also has a new productive asset as well. So much like the homebuyer mentioned earlier, if that buyer puts down a healthy down payment on a house and the monthly payments are affordable relative to their income and expenses, the purchase of the home today may be a prudent and reasonable financial choice rather than waiting to buy the house until sometime in the distant future, deferring any of the benefits of that house until that time, when the homebuyer can pay with cash. The level of debt matters but as important is what the debt is used for and whether the debt payments are reasonable relative to cash flow. In the case of a utility, it is more helpful to examine the trend in the debt-to-assets ratios and the fixed obligation coverage ratios than the absolute value of debt, and a declining debt-to-asset ratio (adding assets faster than debt) is a positive indication over time. The proposed financial policy will achieve a declining debt-to-asset ratio.

Q. IS THIS FINANCIAL POLICY AFFORDABLE TO THE AUTHORITY'S CUSTOMERS?

A. Adoption of the public power model with the proposed minimum debt service coverage ratios is actually more affordable than the rate of return rate setting approach used for IOUs, which is not particularly well-suited to public power utilities like the Authority. Historically, the Authority has followed a form of regulated utility ratemaking policies by targeting a certain level of net income in each year to set its revenue requirements. The Authority is the only large public power utility we are aware of to use this ratemaking. Over the past several years, as the Authority has worked to transition to its new service provider while maintaining a freeze on its delivery rates, the Authority has incurred significant costs that have been deferred for recovery on an accounting and net income basis through the establishment of regulatory assets. This is traditional ratemaking under the regulated utility paradigm but uncommon for a public power utility and has resulted in lower cash flow and fixed obligation coverage. Those accounting deferrals are now coming due for amortization and must be repaid starting in 2016, causing a significant increase in rate requirements under the regulated utility ratemaking model. However, under the public power model, the Authority would directly target the level of cash flow coverage of fixed obligations necessary to meet its financial objectives, resulting in no significant increase in rates in 2016 due to accounting deferrals as the cash outlays for these costs have already occurred. The Authority would instead look to its current cash expenses and debt payments in setting a prudent financial policy in the same manner as other public power utilities.

Q. HOW MUCH MORE EXPENSIVE WOULD THE REGULATED UTILITY APPROACH TO REVENUE REQUIREMENTS BE?

A. No perfect comparison can be made, because some aspects of the traditional IOU approach are not applicable to the Authority. However, rough estimates can be made by reference to the Authority's projected income statements, which are included in PSEG-LI's Ratemaking and Revenue Requirements Panel. That income statement displays how the Authority's Rate Plan would appear using standard financial reporting conventions. The net income results are summarized in Table 3. The Authority would report a loss of $56.4 million over the three year Rate Plan period. Under traditional rate-setting policies, the Authority's rates would need to be at least that much higher. In addition, under the IOU model, some allowance needs to be included for setting a positive "net income target." For an IOU, that amount would be set at the utility's allowable return on equity (or profit margin). A similar concept does not exist for the Authority, which is a customer-funded, not-for-profit, public power authority. In the past, including in the Authority's 2015 approved Operating Budget, the Authority has used a $75 million per year proxy target for net income. Table 3 also provides the results from applying the Authority's prior rate setting philosophy, which is based on the regulated utility approach, to the Authority's proposed Rate Plan. The implication is that customer rates in aggregate would be $134 million higher in 2016, $91 million higher in 2017, and $57 million higher in 2018 compared to the public power approach proposed in the Rate Plan. Thus the regulated utility approach with the $75 million net income target used by the Authority in the past would result in delivery rate adjustments as a percentage of total revenues of 5.7%, 0.8% and 1.0% versus the 2% per year adjustments as a percentage of total revenues proposed in the Rate Plan[7]. The cumulative savings to our customers over the Rate Plan period are $281 million and delivery rates are 1.6% lower at the end of the Rate Plan period.

[7] A delivery rate increase of 2 percent per year of total customer bills is the equivalent of 3.8 percent, 3.9 percent, and 3.9 percent increases on the delivery charge in 2016, 2017, and 2018, respectively.

Table 3: Comparison of Public Power and Net Income Models

	2016	2017	2018	Total
Requested Rate Adjustments (as % of Total Bill)	2.0%	2.0%	2.0%	6.0%
Net Income ($MM)	-$58.5	-$16.3	18.4	-$56.4
Incremental Adjustment ($MM) to Achieve $75 MM Net Income	$133.5	$91.3	$56.6	$281.4
Rate Adjustment to Achieve $75 MM Net Income Target (as % of Total Bill)	5.7%	0.8%	1.0%	7.6%

Q. DOES THE PUBLIC POWER APPROACH FACILITATE RATE STABILITY AND PREDICTABILITY?

A. Yes, it does, as evidenced by the Authority's proposed changes in delivery rates of 2% per year of total revenues compared to the front-loaded adjustments outlined using a $75 million net income target.

Q. ARE NET INCOME LOSSES CONSISTENT WITH SOUND FISCAL OPERATING PRACTICE?

A. In this case, yes they are. Despite the net income losses, the Authority still produces the increasing minimum fixed obligation coverage ratios outlined in Table 2. This is an example of why a net income target is not that useful as a rate setting tool for a public power utility because it targets a financial metric that is not a focus of the ratings analysts or investors, who ultimately determine the Authority's borrowing costs. Under the public power model, the Authority's cash flow will improve over the Rate Plan period and the Authority will pay for a greater share of its infrastructure investments from revenues and less from debt. The Authority's situation is unique in that the net income losses are principally caused by non-cash accounting deferrals, which are further described in Authority Witness Kane's testimony. The Authority's cash flow compared to its fixed costs is roughly flat to 2015 levels in 2016 and then steadily improves during the Rate Plan to a level consistent with achieving the Authority's mid-A target credit ratings.

Q. IS CURRENT COST RECOVERY AN ELEMENT OF A SOUND FINANCIAL POLICY FOR THE AUTHORITY?

A. As PFM stated in its report, the willingness of the Authority and regulatory advisors to establish rates that support credit strength is very important. In order to garner the benefits of an improved financial posture, the Authority needs to generate its projected revenues and cover its costs. As PFM explained, "This rating should be attainable if the Authority adopts, and achieves, target financial metrics that are at the low end of the range of other

"A" rated utilities, *including cost recovery mechanisms that are supportive of the target ratings*" (*emphasis added*).

There are three areas of the Authority's delivery rates that have significant unpredictable elements outside of the Authority's control:

- Debt service costs;
- Power Supply Agreement ("PSA") and LIPA-owned generation costs; and
- Storm costs.

To achieve the goal of higher credit ratings, the Authority is proposing to revise its rate structure to ensure current recovery of the actual costs incurred for these cost categories. The mechanics of the proposed current cost recovery mechanism (referred to as the Delivery Service Adjustment) are addressed by the PSEG-LI Cost of Service and Rate Design Testimony. Current cost recovery would not increase customer cost over time but will enable the Authority to achieve its minimum financial targets, which are set at a low level for a "single-A" credit rating. The alternative would be to set higher coverage targets to allow for the uncertainty of these costs.

Q. PLEASE EXPLAIN THE BENEFITS OF CURRENT COST RECOVERY TO CUSTOMERS.

A. As I have explained, public power financial policy depends on giving bondholders enough certainty of the payment of principal and interest on their bonds that they will be willing to accept an appropriately lower rate of interest on their bonds. Because we are targeting relatively low coverage ratios for the desired credit ratings, which reduces costs in each year to customers, provision for current cost recovery as proposed will give bondholders certainty that customers will pay the costs incurred to serve them, while assuring customers that they will only pay the costs incurred to serve them, and provides the greatest financial benefits to customers at the lowest fiscally sound electric rates over time.

Q. HOW UNCERTAIN ARE DEBT SERVICE COSTS DURING THE RATE PLAN PERIOD?

A. As stated previously, the Authority is intending to pursue additional refinancing of its debt with UDSA securitization bonds during the Rate Plan to produce significant reductions in the cost of debt for our customers. We anticipate savings from such debt refinancing of $155 million during the Rate

Plan. However, the Authority requires statutory authorization to complete the refinancings, as proposed in the Governor's Budget on January 21, 2015. There is also uncertainty about how much debt refinancing will be economic when the securitization refinancings are executed due to changes in interest rates between now and that time. In the Rate Plan, the Authority has included reasonable planning assumptions that include some conservatism in terms of the savings results that can be achieved through refinancing bonds and other financing strategies. The Delivery Service Adjustment will ensure that our customers pay the actual costs incurred for debt payments, including the coverage factor on such costs.

Q. HOW UNCERTAIN ARE DEBT COSTS AFTER THE RATE PLAN PERIOD?

A. In the period after the Rate Plan, the Authority's debt service costs will vary with the capital spending and the general level of interest rates. The Authority's annual Capital Budgets are subject to review by the DPS and approval by the Authority's Board of Trustees. The Authority's Board also approves all bond sales and the Office of the State Comptroller reviews and approves the sale of Authority bonds. The general level of interest rates will impact the Authority's new bond sales, interest rates on outstanding variable-rate debt, and any potential refinancing opportunities. The Authority utilizes reasonable assumptions for interest rates for planning purposes but has little ability to control market conditions.

Q. WHY DOES THE DELIVERY SERVICE ADJUSTMENT INCLUDE COVERAGE ON DEBT SERVICE COSTS?

A. The calculation of the Authority's revenue requirements includes all expenses, plus debt payments and payments on debt-like obligations (fixed obligation payments), plus a coverage factor on those fixed obligations payments. The coverage factor is essentially a percentage of the fixed obligation payments. As described previously, while the Authority has made what it believes to be reasonable and somewhat conservative estimates for fixed obligation payments in each future year, there are significant uncertainties in those estimates that are outside the control of the Authority. If the Authority could project with certainty the actual level of such fixed obligation payments in each year, it could also project with certainty the coverage component of revenue requirements. Absent such certainty, both the fixed obligation payments and the coverage requirement, which is a percentage of those fixed obligation payments, should both be reflected in the Delivery Service Adjustment based on actual fixed obligation costs incurred. The Delivery Service Adjustment only reflects changes in fixed obligation payments and the proportional increase or decrease in the level of coverage associated with changes in those fixed obligation payments. It does not reflect changes to any other expenses.

Q. CAN YOU DESCRIBE THE POWER SUPPLY AGREEMENT?

A. The Power Supply Agreement with National Grid Generation LLC ("NGG") is for the ongoing use of the legacy generating plants on Long Island. The PSA is a cost-of-service contract, which means that NGG recovers its operating costs plus a return of and on the capital it invests in the plants at rates filed with and approved by the Federal Energy Regulatory Commission ("FERC"). Certain costs, including property taxes and pension-related expenses are subject to annual cost adjustment. The PSA is further described in the Testimony of LIPA Witness Shansky and the PSEG-LI Power Supply Panel. The PSA contract is administered by PSEG-LI in accordance with the OSA.

Q. CAN YOU DESCRIBE UNCERTAINTIES AROUND THE COSTS IN THE POWER SUPPLY AGREEMENT?

A. Most power supply costs are recovered from customers on an actual cost basis as part of the Fuel and Purchased Power Adjustment Clause, more commonly known as the Power Supply Charge. The costs associated with the PSA and the Nine Mile Point 2 plant remain within the Authority's delivery rates, although this will be further considered at a later time as described in the PSEG-LI Power Supply Panel testimony. The PSA has an established cost-of-service rate setting process to establish the reasonableness of costs through FERC; however, the costs of the PSA have historically varied from expectation within a range of no greater than 2 percent of budgeted amounts. For example, over the last five years, PSA costs have come in from $4.5 million under budget to $5.4 million over budget. Obviously there is more uncertainty in making a three-year projection of such costs than in making an annual projection through our normal budgeting cycle.

Going forward, there is reason to believe this variation could be wider than the historic level. To focus on one such uncertainty under the PSA contract, I will describe the property tax dispute between the Authority and the taxing authorities in the communities where the generating plants that are part of the PSA are located. The Authority has ongoing litigation to reduce the tax burden on all Long Island customers that is currently being imposed on them by certain taxing jurisdictions, and some allowance for resolution has been included in the revenue requirements for this case. The historical level of these payments are nearly $200 million annually and in our judgment a fair tax assessment for our customers could be half of that level. For purposes of setting rates, the Authority has assumed very conservative benefits to customers associated with a phase-in of tax reductions in the amount of no savings in 2016, $8 million in 2017 and $16 million in 2018. The actual outcome and timing of any benefits from successful litigation or settlement of the outstanding tax disputes cannot be known at this time and actual costs will be reflected through the Delivery Service Adjustment.

Q. HOW UNCERTAIN ARE THE COSTS OF OWNING AND OPERATING AN 18% SHARE OF UNIT 2 OF THE NINE MILE POINT GENERATING STATION?

A The costs of owning and operating the Nine Mile Point generating station have historically averaged within 2 percent of annual budgeted amounts, although there have been larger variances of as much as 10 percent of non-fuel operating costs on both the low and high side. As with PSA costs, obviously there is greater uncertainty in making multi-year projections than we have had historically with annual budget forecasts for the coming year. Additionally, we are advised by PSEG-LI witnesses Paul Napoli and Joseph Trainor that all the costs for owning generation that are included within delivery charges should be handled in the same manner as the costs for the legacy generation represented by the PSA with National Grid.

Q. CAN YOU ADDRESS RECOVERY OF STORM COSTS?

A. Another large uncertainty to the Authority's overall cost of providing safe and reliable service to customers is the projection of storm restoration costs. Customers are fortunate in that the Authority's status as a public power utility makes it eligible for financial reimbursement from FEMA for a percentage of its storm restoration costs that meet certain criteria. Even with the FEMA reimbursements, there are sizable unreimbursed costs in each year that need to be recovered through electric rates, on the order of $45 million or more per year. However, there is wide variation around that average, with unreimbursed storm restoration costs ranging from $31 million to $103 million over the last ten years. With such wide fluctuation, it is not possible to anticipate the single dollar amount that is most appropriate to recover through rates over the three-year Rate Plan or after. Using a current cost recovery mechanism, higher than expected costs would be recovered from customers over time while over-recovery in any year up to a certain dollar amount would be retained in a storm recovery fund to offset future storm-related expenditures. This method of recovery, which balances recovery with predictability for customers, is an appropriate manner to fairly allocate costs over time and is consistent with the public power model of rate setting.

Q. CAN YOU PROVIDE AN ESTIMATE OF HOW THESE CURRENT COST RECOVERY MECHANISMS COULD IMPACT CUSTOMER BILLS?

A. We have budgeted what we believe to be reasonable estimates for these costs – debt service, generation costs, and storm costs -- for the Rate Plan period. So the “budgeted” variance for these costs during the Rate Plan is zero. The Delivery Service Adjustment would reflect actual costs for these cost categories. The largest potential variance is the refinancing savings available from the UDSA refunding of Authority bonds at a lower cost. The savings from this refunding are summarized in the PSEG-LI Ratemaking and Revenue Requirements Panel. A significant portion of this savings should be known before the adoption of the Rate Plan. Table 4 provides selected analyses for each current cost recovery component. In most years, certain items in a budget come in above budget while others come in below, so it is likely that an increase in one component could be partially offset by a decrease in another.

Table 4: Sensitivity Estimates for Delivery Service Adjustment

Component	Scenario	Savings / Cost	Rate Impact % Total Bill
Debt Payments	$400 Million Borrowing with Interest Rates at 4%	-$4 million	-0.1%
	$400 Million Borrowing with Interest Rates at 6%	+$4 million	+0.1%
Power Supply Agreement	Double Projected Property Tax Savings	+$16 million	-0.4%
	No Property Tax Savings	- $16 million	+0.4%
Storm Costs	Storms at or Under Budget or Covered by Reserve	+$0 million	+0.0%
	Highest Storm Year with No Reserve Balance	+$18 million	+0.5%

Q. TURNING TO THE SUBJECT OF THE AUTHORITY'S LEVEL OF CHARGES, HAS THE AUTHORITY BEEN ABLE TO LIMIT INCREASES IN ELECTRIC RATES IN RECENT YEARS?

A. Yes, since 2006, the total cost of electricity on Long Island, including both delivery and fuel charges, has increased a total of 2.2 percent compared to a general increase in the cost of living of 16.4 percent. After inflation, the real cost of electricity has decreased by 14.2 percent over the period. Table 5 has a comparison of the Authority's residential electric rates to other major cost categories for urban households as measured by the Bureau of Labor Statistics. Of note, nationwide, the cost of electricity has increased 24 percent since 2006, or approximately 22 percent faster than the Authority's charges.

Table 5: Authority Residential Electric Rates and Inflation Since 2006

Expense Category	% Increase in Cost Since 2006
Long Island Power Authority (Delivery and Energy)	**2.2%**
Medical Care	29.3%
Food and Beverages	24.4%
Electricity	**24.0%**
Fuels and Utilities	20.0%
CPI-Urban Consumers	**16.4%**
Education	16.4%
Housing	14.6%
Transportation	13.9%

Source: Bureau of Labor Statistics, CPI Detailed Report, December 2006 - December 2014

The Authority maintained a rate freeze at 2012 levels for delivery charges in 2013, 2014 and 2015. The Rate Plan proposes delivery rate increases of 2 percent per year of total customer bills. With the three-year rate freeze, the delivery rate over this six-year period from 2013 to 2019 will have increased approximately 1 percent per year as a percentage of the total bill, which is less than the current or projected rate of inflation.

It is also worth pointing out that the Authority has only increased its delivery rates twice since its inception in 1998 (when rates were lowered by 16.6 percent as compared to LILCO rates then in effect). Those two increases were 1.9 percent and 1.6 percent of the typical residential bill in 2011 and 2012, respectively.

Q. HOW DO THE AUTHORITY'S RATES COMPARE WITH NEW YORK STATE AVERAGES AS A PERCENTAGE OF INCOME?

A. The Authority's rates for residential electric service are below the statewide average for its Long Island service territory as a percentage of median income (see Table 6). The Authority's customers tend to have higher median incomes and use more electricity than the statewide averages. The median household income for the Authority's service territory in 2012 was estimated at $87,624 compared to a statewide average median income of $56,357. The average annual electric bill in the Authority's service territory in 2012 was $1,873 compared to a statewide average of $1,275. Annual use per residential customer averaged 9,845 kilowatt-hours versus a statewide average of 7,116 kilowatt-hours. Reflecting all of these differences, the typical electric bill was 2.1% of the median household income in Nassau and Suffolk Counties in 2012 (the latest year for which statistics are available). This is lower than the statewide average for New York of 2.3% of median income.

Table 6: Typical Residential Bill and Usage for Authority and New York

Service Territory	Typical Residential Bill as a percent of Median Household Income	Annual Use per Customer KwH
Long Island Power Authority	2.1%	9,845
State of New York	2.3%	7,116

Source: EIA Form 826; U.S. Census Bureau Small Area Income and Poverty Statistics

Q. DOES THIS COMPLETE YOUR PRE-FILED DIRECT TESTIMONY AT THIS TIME?

A. Yes.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan

Matter Number: 15-00262

REBUTTAL TESTIMONY OF

THOMAS FALCONE

LONG ISLAND POWER AUTHORITY

JUNE 10, 2015

Matter Number: 15-00262 Rebuttal Testimony of Thomas Falcone

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Thomas Falcone, Chief Financial Officer of the Long Island Power Authority (the "Authority") and the Utility Debt Securitization Authority ("UDSA"), 333 Earle Ovington Boulevard, Suite 403, Uniondale, New York 11553. My educational background and professional experience are summarized in my pre-filed testimony.

Q. CAN YOU PROVIDE YOUR OVERALL REACTION TO DEPARTMENT STAFF'S TESTIMONY?

A. Yes. I have reviewed the recommendations of the Staff ("Staff") of the New York State Department of Public Service ("Department") related to financial policy and revenue requirements. The Authority welcomes constructive critique, which is essential to our statutory mission of providing safe and reliable service at the lowest rates consistent with sound fiscal operating practices. In particular, we appreciate Staff's analysis of the "public power model" and Delivery Service Adjustment ("DSA") and its recommendation to use this approach to ratemaking for the Authority, which we believe will result in lower cost for our customers over the course of this three-year rate plan and over time, less debt relative to assets, and higher credit ratings.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. There are two elements of Staff's direct testimony where we agree, but wish to provide clarification so as to ensure we properly reflect revenue requirements and policy goals. Specifically, I discuss:

- Staff's recommendation to create a cap on the balance owed to customers in the storm reserve component of the DSA, and to use any amounts in excess of the cap for the benefit of customers, which we believe is both reasonable and desirable, and therefore wish to clarify our understanding of the cap mechanism.
- The need for a "second stage" process that updates the Authority's rates to account for items that are uncertain today, but will become known and measurable as 2016 unfolds, as described beginning on line 12 of page 36 of Staff's Revised Policy, Overview and Revenue Requirement's Panel ("PORR"). The Authority proposes that a "second stage" update process, limited in scope as suggested by Staff, could update the following material costs:
    - The actual savings in debt service as a result of the two UDSA bond refinancing transactions that the Authority expects to complete by mid-2016;
    - An update to bond debt service payments, including using a then-current benchmark for yet unissued tax-exempt bonds, as well as

the need to adjust debt service payment projections on such unissued bonds for tax-exempt bond market conventions;

- An update to the projection of PSEG Long Island ("PSEG LI") labor costs and associated agreements based upon the then-known costs of the collective bargaining agreement ("CBA") that PSEG LI expects to complete following the expiration of the current CBA on November 12, 2016;
- An update for actual property tax payments-in-lieu-of-taxes ("PILOTS"); and
- Costs associated with changes in rules, laws, regulations or orders (or other requirements of the federal, state and local governments or courts) that subsequently impose expenses that were not anticipated in the forecasts upon which the rate plan was developed.

Q. AT PAGE 35 OF ITS PREPARED TESTIMONY, THE DELIVERY SERVICE ADJUSTMENT AND STORM RESERVE PANEL RECOMMENDED A MODIFICATION TO THE STORM RESERVE COMPONENT OF THE DSA. DO YOU AGREE WITH THAT RECOMMENDATION?

A. Yes. We believe Staff's recommendation to create a cap on the balance owed to customers in 2017 or 2018 is reasonable. As stated in its testimony, "*In the* *event that either of these caps is triggered, we recommend the reserve balance be reset to the base rate allowance level in that rate year and that the difference between rate year allowance and the cap be utilized by LIPA to pay down LIPA's debt, or offset other DSA cost components in the tracking period that the caps are reached.*"

Q. WHAT IS YOUR UNDERSTANDING OF HOW THE STORM RESERVE TRACKING PROCESS WOULD WORK?

A. Starting in January 2016, the amount of revenue collected through rates each month to satisfy the storm reserve will be added to the Storm Reserve Account. In addition, each month starting in January 2016 the amount of expense incurred to pay for eligible storm costs will be deducted from the Storm Reserve Account. This will create positive amounts (owed to customers) or negative amounts (due from customers) that will accumulate over time, either positively or negatively. As of September 30th of each year, which is the end of each tracking period, the balance in the Storm Reserve Account will be evaluated. In the event that the amount in the Storm Reserve Account owed to customers exceeds the cap (approximately $75 million or 1.5x the annual recovery level for storms in the year, as recommended by Staff), an adjustment will be triggered which will reduce the balance remaining in the account (owed to customers) to the annual recovery level for that year (approximately $50 million), and the excess amount will be returned to customers.

Q. WHAT IS YOUR RECOMMENDED TREATMENT OF THE AMOUNT REMOVED FROM THE STORM RESERVE ACCOUNT?

A. Staff recommended that the difference be returned to customers either by reducing debt or reducing the DSA in the subsequent recovery period. The Authority proposes that the downward adjustment in the reserve balance be used to reduce the Authority's debt. The amount removed from the Storm Reserve Account (approximately $25 million in the example above) would be deposited in the Authority's Construction Fund, which would otherwise have been funded through additional debt. By placing the adjustment directly into the Construction Fund, Staff can verify that the amount was used to reduce borrowing in the year, and was not diverted to any other use. Furthermore, I would emphasize that using the adjustment to reduce borrowings in the year is equivalent to paying down existing debt. It is also more immediate and less expensive than retiring existing debt, since there are logistical and financial hurdles associated with retiring existing debt that introduces delays and additional costs into the process. As described beginning on line 8 of page 27 of Staff's Revised Finance and Public Power Panel ("SFPP"), the Authority has high debt levels relative to capitalization, which has been a consistent cause of public discussion. Using lower than expected storm-related costs to reduce debt, should that occur, is consistent with providing a benefit to our customers in the form of lower future electric rates.

Q. WHAT WOULD CHANGE IN THE DRAFT TARIFF LANGUAGE IF YOUR PROPOSAL WERE ACCEPTED?

A. Three clarifying changes to the draft tariff language would be required. First, the statement that the customer contribution to the storm reserve would be added at the beginning of the year should be modified to state that the contribution will be added monthly as they are reflected in rates. Second, the statement that the provisions for the cap be evaluated at the end of each tracking period should be emphasized. We do not think it is appropriate to impose the cap in the middle of the tracking period because a major storm could occur subsequent to the trigger event that would dip further into the storm reserve than intended. Third, explicit wording to indicate that the trigger event will cause the transfer of funds between the Storm Reserve Account and the Construction Fund should be added.

Q. PLEASE COMMENT ON THE PANEL'S RECOMMENDATION THAT STAFF REVIEW THE ANNUAL FILING OF THE DSA.

A. As stated on page 37 of the Panel's prepared testimony, the Panel is requesting that the annual "*filing should be submitted to the DPS staff no more than 30 days following the conclusion of each tracking period*. {…} *Staff will report their findings and recommendations to LIPA's Board of Trustees for its consideration one week prior to the annual December meeting of the LIPA Board*." Staff's recommendation that it review the calculations supporting the DSA is appropriate, and generally conforms with the timing included in PSEG LI's draft tariff leaves. We would request that the Staff provide its recommendation to the Authority's Board of Trustees by the end of November each year, to allow the Authority staff and the Board time to evaluate the comments and corrections provided by the Staff.

Allowing Staff 30 days to review the annual filing should not represent an unreasonable burden on Staff, because it will also be receiving and monitoring the balances in the DSA accounts on a monthly basis, as these items will be separately listed in the Authority's financial results each month. To the extent that the balances due to or due from customers exhibit any unusual or unexpected behavior, Staff will be seeing that progressively through the year, and will have all the information needed, and any concerns can be identified and investigated well before the annual filing is prepared and provided.

Q. STAFF'S FINANCE AND PUBLIC POWER PANEL RECOMMENDED DOWNWARD ADJUSTMENTS TO THE AUTHORITY'S ESTIMATES FOR FUTURE DEBT SERVICE. WHAT ARE THE CAUSES OF THESE REDUCTIONS?

A. The downward adjustments to the estimates for future debt service and fixed obligation coverage requirements reflect reduced or deferred capital spending (and thus reduced borrowing) during the rate plan in combination with a reduction to the Authority's interest rate assumptions used for budgeting purposes for future borrowings and outstanding variable rate debt. We agree with the first change—to the extent recommendations are made in this proceeding that result in less future borrowing or debt outstanding, those recommendations should be reflected in the level of projected debt. We also acknowledge the inherent uncertainty around future interest rates and their impact on projected debt service payments and coverage. This inherent uncertainty in future interest rates, as well as the desire that customers pay only the actual costs rather than budgeted interest rates, were among the factors that led the Authority to propose the DSA. Staff supported the Authority's proposed DSA for debt service and fixed obligation coverage.

Q. DOES THE AUTHORITY AGREE WITH STAFF'S PROPOSAL TO USE CURRENT INTEREST RATES TO CALCULATE DEBT SERVICE COSTS, AND HENCE REVENUE REQUIREMENTS?

A. Yes. The reductions reflect, as stated on lines 6 and 7 of page 32 of the SFPP Panel "…the Department's established methodology of [using] current interest rates," which is based on the Department's belief, as stated on lines 13-15 of page 31 of SFPP, "that current rates are the most accurate predictor of the costs of future debt issuances." In setting the Authority's rates for the coming year, the use of current interest rates as a proxy for the future is a reasonable and less controversial method than debating the merits of alternative projections of this highly uncertain item. For the longer term, however, such as the full three years of the Authority's three-year rate plan, there is a significant risk that current interest rates will underestimate future interest rates in 2017 and 2018.

Q. ARE THERE WAYS TO MITIGATE THE POTENTIAL FOR UNDERESTIMATING DEBT COSTS DURING THE RATE PLAN RELATED TO LOWER INTEREST RATE BUDGET ASSUMPTIONS?

A. Yes. The most effective mitigation is the debt service component of the DSA, which Staff has recommended. Staff suggested another such potential method of mitigation on lines 17-18 of page 33 of SFPP: that "the interest rates should be updated as this proceeding progresses." We concur and believe a final update to interest rates for the rate plan period should be made, in conjunction with Staff, based on then prevailing interest rates as close to the Board's consideration of the rate plan as possible. We recommend a final update reflecting actual known, interest rates in early to mid-November, in anticipation of Board consideration which could occur as late as mid-December 2015.

There are several other practical mitigating steps that Staff and the Authority could take. The Authority anticipates completing the first of multiple UDSA refinancings, the savings of which are projected in the rate plan, by October 2015. An update after that first financing will permit the actual known interest rate of the first (of several financings) to be reflected in the rate plan. However, this will only reflect changes occurring in 2015—prior to the beginning of the three-year rate plan.

Additionally, Staff suggested beginning on line 12 of page 36 of Staff's revised PORR Panel a "second stage" update process, which PSEG LI and the Authority also support as a practical step to mitigate these uncertainties. This "second stage" process amounts to an updating of the delivery rates to be set in this proceeding for January 1, 2017 and January 1, 2018 to promote the use of current, known, and verifiable data and correspondingly avoid basing future rate adjustments on stale and outdated information and projections. This "second stage" update process is consistent with the basic rate framework envisioned by the LIPA Reform Act, as suggested by Staff and endorsed by PSEG LI and the Authority.

Q. WHAT COSTS WOULD BE UPDATED IN A "SECOND STAGE" UPDATE PROCESS IN NOVEMBER 2016?

A. The Authority believes it will have completed the second (of several) UDSA bond refinancings by the fall of 2016. These UDSA refinancings provide significant rate relief during the three-year rate plan period with debt service savings budgeted in our original filing at $155 million. Therefore, the outcome of the financings is a significant uncertainty in revenue requirements. The availability of these savings is highly dependent upon future market conditions. Additionally, the Authority will have completed the issuance of certain other Authority bonds projected in the rate plan to finance capital additions and refinance variable-rate debt. Second, the effect of then-prevailing interest rates on the Authority's variable-rate debt as well as then-current market long-term borrowing rates for future projected borrowings in 2017 and 2018 could be reflected at that time. Third, we expect that PSEG LI will have completed its negotiation of a new CBA with its union-represented workforce by this time, and definitive updates to labor costs and associated agreements should be known. Fourth, more up-to-date and complete information will be available on the status of the property tax PILOTS to be paid on the Authority's transmission and distribution property. We would also include the quantifiable costs of any new legislative, regulatory, or court imposed costs that become known subsequent to the adoption of the rate plan. We suggest that PSEG LI and the Authority submit to Staff for its review a "second stage" submittal, covering these five items, to update base rates to be effective on January 1, 2017 and January 1, 2018.

Q. DO YOU HAVE A RECOMMENDATION ON HOW THIS "SECOND STAGE" UPDATE PROCESS WOULD WORK?

A. Yes. I recommend that the Authority and PSEG LI prepare a submittal that updates the base rates for the above five quantifiable items, as recommended by the Department and designated by the Board of Trustees in its December 2015 decision on the three-year rate plan. The submittal will address only those issues designated by the Trustees and will conform to the calculations approved by the Trustees in their December 2015 resolution adopting the three-year rate plan. I propose that the "second stage" submittal be provided to the Trustees and Staff on or about November 17, 2016. Of note, PSEG LI's existing CBA expires on November 12, 2016. Under this schedule, which reflects that updated labor costs may not be known until mid-November 2016, Staff and the Board would have approximately 30 days to review the calculation for conformance with the Board's resolution on the three-year rate plan, and Staff could provide a recommendation to the Trustees prior to their regularly scheduled meeting, which would most likely be held in mid-December 2016. The Board of Trustees would then be asked to vote on the "second stage" update to the rates for 2017 and 2018 at that December 2016 meeting, the same meeting at which the Board would be asked to approve the annual budget for 2017.

Q. HAVE YOU PREPARED AN EXAMPLE OF THE FORM OF THE "SECOND STAGE" UPDATE SUBMITTAL THAT THE BOARD OF TRUSTEES MIGHT ADOPT IN REGARD TO THE THREE-YEAR RATE PLAN?

A. Yes. Exhibit ___ (TF-1 Rebuttal) provides a suggested format for the "second stage" update that the Department could recommend and the Trustees could consider for adoption in December 2015. It lays out what would be the then-known parameters and calculations that could be considered, and how the results of those calculations could be translated into base rates. This is only one example of how the final document might be constructed, and I look forward to discussing and reviewing this recommendation with Staff and other parties to reach a common understanding.

Q. HOW WOULD EXHIBIT __ (TF-1 REBUTTAL) BE USED FOR THE PROPOSED "SECOND STAGE" PROCESS?

A. Exhibit ___ (TF-1 Rebuttal) includes columns for "projected costs" in 2017 and 2018. The intent would be that these columns would be initially populated with the values approved by the Authority's Trustees in its decision on the three-year rate plan. At the time of the proposed "second stage" submittal, the values for these approved items would be populated with the then-known and measurable values, and the difference from the projected values would be applied to the rates to become effective in 2017 and 2018.

Q. WHY IS 2016 SHOWN ON EXHIBIT ___ (TF-1 REBUTTAL)?

A. My reason for including 2016 on the exhibit is to suggest that the same methodology being considered for the "second stage" submittal could be applied to the planned update for 2016 through 2018 that is expected to occur in the November 2015 timeframe. In this application, the "projected" columns could be developed from the values contained in the Department's September 28th recommendation, in anticipation of the Trustee's final decision, or using a range for values for cost items that are still unknown at that point in the process, such as the outcome of the first UDSA refinancing, which likely be completed in October 2015.

Q. WHAT PROVISIONS WOULD BE MADE FOR PUBLIC REVIEW AND COMMENT ON THE "SECOND STAGE" PROCESS?

A. I recommend that the "second stage" update process be noticed in the State Register and that public comment sessions be held in both Nassau and Suffolk counties as part of the Authority's annual budget process. The Authority already provides for public comment on its annual budget prior to Board consideration, and the update to the Authority's rates would be an integral part of that process. The Board resolution accepting, rejecting or modifying the Authority's base rates for delivery service on the basis of the "second stage" updates would be adopted in mid-December 2016 for rates to be in effect on January 1, 2017 and January 1, 2018.

Q. DO YOU HAVE SOME SUGGESTED WORDING FOR CHANGES IN RULES, LAWS, REGULATIONS OR COURT ORDERS THAT COULD BE INCLUDED IN THE AUTHORIZATION FOR A SUBSUQUENT PROCESS?

A. Yes. I recommend that the authorization for the "second stage" or other process included in the Trustee's resolution adopting the three-year rate plan include the following provision.

> <u>Legislative, Regulatory and Related Actions.</u>
> If at any time any rule, law, regulation or order, or other requirement or interpretation (or any repeal or amendment of an existing rule, regulation, order or other requirement) of the federal, State of New York, or local government or courts, results in a change in the Authority's annual costs or expenses not anticipated in the forecasts upon which the Rate Plan is based, The Authority Board of Trustees, pursuant to its obligations under the Long Island Power Authority Reform Act (LRA), and such other legal obligations as may be applicable, may make such amendments to the Rate Plan as in its judgment are warranted under the circumstances. In the event the Authority finds it necessary to invoke this provision, it shall give notice to the Long Island Office of the DPS, and afford the DPS an opportunity to make recommendations pursuant to the LRA. Such amendments to the Rate Plan would be deemed part of the decision under the Rate Plan, and additional public notice would not be required under the terms of the LRA except as may be considered necessary as part of the Authority's obligations for public notice regarding its annual budget process.

Q. DOES THE AUTHORITY HAVE SUGGESTIONS CONCERNING FUTURE INTEREST RATE UPDATES?

A. Yes. First, as both the Authority staff and Department Staff have pointed out, there are a number of elements of the Authority's cost of service that vary with interest rates. The key components include:

- Debt service payments on the Authority's fixed and variable rate debt, and related credit facilities (notes, commercial paper and revolving bank facilities);
- Debt service payments on the UDSA debt;
- Interest rate swap payments;
- Interest income on the Operating Fund and Rate Stabilization Fund; and
- Fixed Obligation Coverage requirements on the Authority's debt service.

All of these items should be updated in the "second stage" process to reflect both the latest known costs and the "then current" interest rate environment. Second, there is a generally accepted municipal bond market information service available in Municipal Market Data (the "MMD Index"), which the Authority suggests should be used to estimate the Authority's borrowing costs for the purpose of future updates to debt service costs, whether during this proceeding or in a "second stage" process. If requested, the Authority will make sure that Staff has access to this resource. The Authority's borrowing cost can be better approximated by using the MMD Index to adjust for the premium coupons commonly used in the tax-exempt bond market and their impact on principal and interest payments.

Q. CAN YOU DESCRIBE THE AUTHORITY'S INTEREST RATE SWAP CONTRACTS AND HOW THEY VARY WITH INTEREST RATES?

A. The Authority has two types of interest rate swaps: (i) floating-to-fixed rate swaps, that convert the payments on its variable-rate debt to a fixed rate; and (ii) basis swaps, that exchange payments based on the relationship between two floating rates indices. Exhibit ___ (TF-2 Rebuttal) is the report on interest rate swap contracts to the Authority's Board as of March 31, 2015. The projected cost of variable rate bonds must include the net effect of these interest rate swaps.

Q. CAN YOU DESCRIBE THE AUTHORITY'S INVESTMENT RETURN ASSUMPTIONS AND HOW THEY VARY WITH INTEREST RATES?

A. Yes. The Authority has estimated its cash balances and interest earnings during the rate plan period using interest rate budget assumptions that increase over the period consistent with the increasing interest expense assumptions on its variable-rate debt. In this manner, the variances between assumptions and actuals on short-term interest earnings partially offset similar variances on variable-rate debt expense. Modifying the expense of variable-rate debt but not the related assumptions for income understates the net cost of the variable-rate debt and revenue requirements.

Q. SHOULD THE DSA CAPTURE CHANGES IN INTEREST RATES FOR INTEREST RATE SWAPS AND CASH BALANCES?

A. Yes. The effect of interest rate assumptions on interest rate swaps and the earnings on cash balances should be part of the debt service component of the DSA. The DSA is intended to capture the net effect of the swings in interest rates on revenue requirements. Changes in interest rate assumptions on variable-rate debt are partially offset by changes in receipts on interest rate swaps and interest earnings on cash balances. The Authority suggests that the debt service component of the DSA exclude earnings on dedicated funds and irrevocable trusts, such as the Nuclear Decommissioning Trust Fund, for the Authority's ownership interest in Nine Mile Point generating station.

Q. SHOULD THE KNOWN AND MEASURABLE IMPACTS OF FUTURE UDSA REFINANCINGS BE INCLUDED IN THE "SECOND STAGE" ADJUSTMENT?

A. Yes.

Q. CAN YOU DESCRIBE THE UDSA REFINANCINGS?

A. The UDSA transactions refinance Authority bonds, which carry credit ratings of Baa1, A-, and A-, respectively, with UDSA bonds that carry Aaa (sf), AAA (sf), and AAA (sf) ratings. The Authority budgeted $155 million of lower debt service payments during the three-year rate plan period in its original filing from the refinancing of up to $2.5 billion of Authority bonds with UDSA bonds. There are approximately $2.5 billion of Authority fixed-rate bonds that are callable (*i.e.*, can be bought back from their owners at their face value of 100 or "par") between 2016 and 2019. Therefore, the Authority can issue UDSA bonds at lower interest rates and use the proceeds to buy back the Authority bonds that pay higher interest rates at par. The Authority estimated in the rate plan filing that the lower interest rates from the UDSA debt would allow the Authority to realize roughly $155 million in reduced principal and interest payments on the UDSA refunding bonds relative to the currently outstanding Authority bonds during the rate plan. With the additional benefit of lower coverage requirements on UDSA bonds, $155 million of debt service savings provides a total reduction in revenue requirements of $332 million for our customers during the three-year rate plan. As mentioned previously, the Authority expects to refinance these bonds in several refinancing transactions during the rate plan period (given their various call dates) so as to maximize savings for our customers. The Authority was statutorily authorized to issue additional UDSA bonds by a bill passed by the New York Legislature and signed by the Governor in April 2015, and Authority staff plans to seek a financing order to permit the first of these refinancings from the Board of Trustees at its June 26, 2015 meeting.

Matter Number: 15-00262 Rebuttal Testimony of Thomas Falcone

Q. IS IT TYPICAL TO FILE A RATE PLAN WITH PROJECTIONS OF SAVINGS FROM FUTURE REFINANCINGS?

A. While it is not unusual for a municipal utility to take projections of savings on planned refinancings into account in their budgeting processes, I am advised by counsel that it would be more customary in this type of rate proceeding to reflect the currently scheduled costs on the outstanding bonds rather than to budget uncertain savings from refinancing those bonds at some point in the future (for example, the last of these UDSA refinancings may not be completed until 2017 or 2018). However, this was among the reasons the Authority proposed the debt service component of the DSA—so that customers would see the benefit of the refinancings in electric rates and pay the actual debt service cost as incurred. The Authority submitted a rate plan filing that takes into account the expected savings, and will then employ the "second stage" filing and DSA, if adopted, to adjust for the actual amount of savings achieved during the rate plan period relative to the budgeted amount.

Q. CAN YOU DESCRIBE THE METHOD USED TO ARRIVE AT THE $155 MILLION OF BUDGETED DEBT SERVICE SAVINGS?

A. Yes. The $155 million of budgeted debt service savings reflected in our original filing was a reasonable projection of the savings that may be available from the UDSA refinancings, taking into account various structuring limitations and policy goals of the Authority. Specifically, the Authority utilized current interest rates as of the rate plan filing in January 2015, but as with all other interest rate assumptions described previously, adjusted those current interest rates to reflect a rising interest rate environment consistent with market expectations. The Authority then used those projected interest rates to select bond refinancing candidates in a manner that would optimize savings over time. So the Authority's interest rate assumptions for the UDSA refinancings were based on market expectations for interest rates at the times in the future when the Authority expects to refinance the bonds. Combined with the debt service component of the DSA to true up to the actual cost incurred, this appeared to us to be a fiscally prudent approach, while also providing a more probable estimate of revenue requirements.

Q. WILL ALL OF THE SAVINGS FROM THE UDSA REFINANCINGS BE REALIZED DURING THE RATE PLAN PERIOD?

A. At the time of the rate plan filing, the "present value" savings or difference between the principal and interest payments on the outstanding Authority bonds and the projected payments on the new UDSA bonds over the life of the bonds using budgeted interest rates was approximately $192 million. Of that, $155 million was budgeted to be realized during the three-year rate plan period. This allocation of the savings between the rate plan years and future periods reflected both bond structuring limitations and policy goals. On structuring limitations, the UDSA refinancings do not target a single Authority bond, but rather up to 180 individual Authority bond maturities. The refinancing of these 180 individual Authority bond maturities will be accomplished with the sale of approximately 50 new UDSA bond maturities. The refinancing has to pass various rating agency "stress tests" in order to achieve the "triple-A" bond ratings, so the structuring of the transaction is complex, taking into account many constraints. The policy goals served by the UDSA refinancings are discussed below.

Q. ARE DEBT SERVICE SAVINGS THE ONLY SAVINGS CUSTOMERS EXPERIENCE FROM THE UDSA REFINANCINGS?

A. No. As mentioned previously, our customers also benefit from reduced revenue requirements from lower "coverage" requirements on the UDSA bonds. As described above, approximately $155 million of the $332 million of budgeted savings during the rate plan is from lower debt service requirements. The remaining $177 million is from lower coverage requirements. The lower coverage requirements are realized for the entire term the UDSA bonds remain outstanding.

Q. IS EVERY AUTHORITY BOND MATURITY REFINANCED WITH AN IDENTICAL UDSA BOND MATURITY?

A. No. Given the large number of bonds involved and the need to meet rating agency stress tests, various Authority bond maturities are refinanced by each UDSA bond maturity, and each UDSA bond maturity may only refinance part of an Authority bond maturity. The overall effect is to provide our customers with lower debt service payments (principal and interest) over the life of the bonds and present value savings, but for the reasons mentioned and others, it is not a like-for-like refinancing of one bond with another. Instead, the principal and interest payments on the UDSA bonds have to be re-amortized at current market interest rates at the time of each financing to produce the desired effect over the life of the bonds. Based on market rates at the time of issuance, the UDSA bonds will be able to generate a certain amount of net present value savings, and a portion of this present value savings can be structured into the rate plan period.

Q. GIVEN THESE FACTORS THAT INFLUENCE THE UDSA REFINANCINGS—THE PREVAILING LEVEL OF INTEREST RATES FOR THE AUTHORITY AND UDSA DEBT, THE SAVINGS ON FIXED OBLIGATION COVERAGE, AND RESTRUCTURING OF PRINCIPAL

PAYMENTS TO MEET MARKET EXPECTATIONS—CAN YOU DESCRIBE THE POLICY GOALS FOR THE UDSA REFINANCINGS?

A. Yes. The Authority expects to structure the realization of the present value savings from refinancing the Authority bonds with UDSA bonds in such a way as to meet cash flow savings and customer rate objectives over time, balanced with the need to meet the securitization structuring requirements imposed by the rating agencies. The customer rate objectives include providing significant savings during the rate plan period from the refinancings while not causing a spike or "cliff" in revenue requirements at the end of the rate plan.

This policy issue can be seen in the graph contained in Exhibit ___ (TF-3 Rebuttal). The solid line in that graph shows the Authority's existing debt service on bonds (*i.e.*, without the benefit of the 2015 and 2016 UDSA refinancings). Note that additional refinancings may occur beyond 2016. Also note, among other things, that the existing level of debt service payments is approximately $562 million in 2019, and stays around that level for the remainder of the chart. Our proposed securitization plan, as included in the rate plan filed in January, was to reduce the debt service payments significantly in 2016, 2017 and 2018, reduce them somewhat in 2019, and largely maintain the status quo thereafter. With lower interest rates, we have the potential to reduce debt service in 2019 below what was originally planned, and reduce debt service in 2020, before returning to the originally planned levels in 2021. This smoothing of the increase in debt service costs would create a more affordable rate path for the Authority's customers in the future, and represents a more reasonable strategy for the use of additional interest rate savings that might be achieved.

Q. CAN YOU PROVIDE AN UPDATE TO THE UDSA REFINANCING SAVINGS ASSUMING ALL FUTURE REFINANCINGS ARE SOLD AT TODAY'S INTEREST RATES?

A. Yes. Present value savings using current market rates as of May 26, 2015 would be approximately $249 million as compared to the $192 million filed in January 2016. The transaction would provide $172 million of debt service savings during the rate plan years, but would also provide an additional $45 million of cash flow savings in the two-year period beyond the rate plan, with a more gradual phase-in of any difference in revenue requirements. A comparison of the cash flow savings as filed in January and as of today appears on the second page of Exhibit ___ (TF-3 Rebuttal). I specifically draw attention to the change in debt service for 2019; this is where the majority of the additional savings from lower interest rates would occur, if interest rates remain lower than originally projected. The actual savings will not be known until all of the refinancings occur. We expect the majority of the refinancings to occur in 2015 and 2016, but the balance may not occur until later in the rate plan period.

Q. CAN YOU DESCRIBE THE TAX-EXEMPT BOND BENCHMARK MMD INDEX?

A. Yes. The MMD Index is used by virtually all tax-exempt bond market participants, including issuers, advisors, broker-dealers and investors. The MMD index is the benchmark index in the tax-exempt municipal bond market, much like U.S. Treasuries are used as the benchmark used by market participants in the taxable bond market. The MMD Index is published daily and there are releases and commentary on the index throughout each trading day. The Index is published for each bond maturity from one to 30 years. There are also indices for various credit rating categories.

Tax-exempt bonds are compared to the MMD Index for a like maturity (*i.e.*, a 10-year bond is compared to the 10-year MMD Index). All new bond issue pricing is quoted in terms of a particular bond's "spread to MMD." This refers to the additional yield above the AAA MMD Index a bond pays for that bond's maturity.

The Authority proposes to establish debt service estimates that support future borrowing for capital projects and new UDSA refinancings based on the MMD indices on a given day plus an average "spread to MMD." We would calculate the average "spread to MMD" from the Authority's most recent bond sale as applied to each maturity of the "Single-A" MMD Index and the same for UDSA bond sales as applied to the "Double-A" MMD Index. The Authority has included a sample of such calculation in Exhibit ___ (TF-4 Rebuttal). The Authority has filed its revenue requirements assuming its new money bond sales are structured to produce "level debt service" payments (similar to a home mortgage with each year's debt service payments for the bond series being equal) over 30 years with an interest-only period (*i.e.*, no principal payments) for the first three years.

Q. ARE THERE ANY OTHER ADJUSTMENTS THAT SHOULD BE MADE TO REFLECT THE INTEREST COSTS ON THE AUTHORITY'S DEBT SALES DURING THE RATE PLAN?

A. Yes. As we update the Authority's projected debt service costs for changing interest rates, the Authority's cost of funds must be adjusted to reflect the manner in which municipal bonds are priced and sold, which the Authority accomplishes with its proposed approach using the MMD Index. Specifically, the payments on the Authority's bonds must be adjusted to reflect the initial premium likely to be received when the bond is issued. Failure to make this adjustment will understate the cost. Staff's Exhibit ___ (SFPP-11) proposes a method to update interest rates on future borrowings based on then prevailing market conditions, but does not take this nuance of premium coupons in the tax-exempt bond market into account.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE ADJUSTMENT THAT NEEDS TO BE MADE TO REFLECT BOND PREMIUMS TO FORECAST DEBT SERVICE COSTS ON FUTURE BOND SALES?

A. Yes. As an example, Exhibit ___ (TF-5 Rebuttal) uses the coupons and yields provided in Exhibit ___ (TF-4 Rebuttal) to show debt service payments if the Authority were to seek to raise $100 million in the bond market at today's bond yields. Of note, the Authority would only issue $90.2 million of bonds to raise $100 million of proceeds as the prevailing market coupon is 5.00%, while the stated yields (generally the "yield-to-call" or yield to when the bond becomes callable in ten years) on bonds are less than the 5.00% coupons, and therefore, the bonds have dollar prices above $100. For example, a bond maturing in 2046 would have a 5.00% coupon with a 4.00 yield-to-call and a dollar price of 108.176. Importantly, the "true interest cost" if all of the bonds remain outstanding to maturity is 4.16%, but the average interest payments in 2016 are equivalent to 4.51% of the $100 million of bond proceeds.

The importance of this is that if the Authority were to use Staff's approach to calculate revenue requirements as provided in Staff's Exhibit ___ (SFPP-11) for new money borrowings using the stated yield (which is the yield-to-call, not reflecting a 5% premium coupon) on a 25-year maturity as a proxy for the Authority's borrowing cost (currently 3.93%), it would understate the interest payments to be paid to bondholders during the rate plan years (and therefore revenue requirements) by approximately 58 basis points (0.58%) or 13%, which is the difference between the 4.51% average interest payments on bonds sold today at current market yields and the 3.93% yield to call on a 25-year bond. By 2018, this could understate revenue requirements for the new money borrowing component of debt service costs, using current market rates as provided in this example, by approximately $9.5 million annually. The Authority's recommendation in this regard is that the Authority assumes the use of prevailing market debt structures and indices that are widely accepted throughout the industry for the purpose of estimating future debt service costs on yet to be issued debt.

Q. DOES THIS COMPLETE YOUR PRE-FILED REBUTTAL TESTIMONY AT THIS TIME?

A. Yes.

JUDGE PHILLIPS: The next witness testimony that was going to be entered by affidavit is listed as the Staff Finance Panel. Do you have the affidavit.

MR. MAZZA: I do. Thank you, Your Honor. I would like to enter into the record the testimony and exhibits of the Staff Finance and Public Power Panel consisting of Patrick Piscitelli and Kwaku Duah. The documents themselves are Prepared Revised Testimony of the Staff Finance and Public Power Panel.

The document consists of 43 pages plus a title page, Prepared Revised Exhibits of the Staff Finance and Public Power Panel, SFPP-1 consisting of five pages, Exhibit SFPP-2 consisting of one page, Exhibit SFPP consisting of 17 pages, Exhibit SFPP-4 consisting of 39 pages, Exhibit SFPP-5 consisting of eight pages, Exhibit SFPP-6 consisting of ten pages, Exhibit SFPP-7 consisting of nine pages, Exhibit SFPP-8 consisting of 15 pages, Exhibit SFPP-9 consisting of two pages and finally Exhibit SFPP-10 consisting of one page.

Actually, I misspoke. Exhibit SFPP-11 consisting of three pages, Exhibit SFPP-12 consisting of three pages plus a cover page and indexes and that concludes the documents, Your Honors.

JUDGE PHILLIPS: Have you provided a copy of the affidavit?

MR. MAZZA: It is on its way. Thank you, Your Honors.

MR. FORST: (Handing).

JUDGE PHILLIPS: The affidavit will be marked for identification as Exhibit 108. It is the revised Finance and

Public Power testimony dated June 8th, I believe. It is 43 pages, and that should be copied into the record as though orally given on the basis of the affidavit. Thank you.

MR. MAZZA: Thank you, Your Honor.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

In the Matter of a

THREE-YEAR RATE PROPOSAL FOR ELECTRIC RATES AND CHARGES SUBMITTED BY THE LONG ISLAND POWER AUTHORITY AND SERVICE PROVIDER, PSEG LONG ISLAND LLC.

Matter Number 15-00262

June 2015

Prepared Revised Testimony of:

Staff Finance and Public Power Panel

PATRICK PISCITELLI
Principal Utility Financial Analyst

KWAKU DUAH
Associate Utility Financial Analyst

Office of Accounting, Audits and Finance
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Q. Please state the names of the members of the Staff Finance Panel or Panel.

A. We are Patrick Piscitelli and Kwaku Duah.

Q. Mr. Piscitelli, please state your current employer and business address.

A. I am employed by the New York State Department of Public Service, or Department. My business address is Three Empire State Plaza, Albany, NY 12223.

Q. In what capacity are you employed by the Department?

A. I am employed as a Principal Utility Financial Analyst in the Office of Accounting, Audits, and Finance.

Q. Please describe your educational and professional background.

A. My educational and professional background is summarized in pages 1 and 2 of Exhibit___(SFPP-12), attached.

Q. Have you previously testified in utility regulatory proceedings?

A. Yes, I have 34 years of experience testifying on various regulatory issues. Most recently, I have testified in the Niagara Mohawk Power

Corporation Proceedings, Cases 08-G-0609, and 10-E-0500 before the New York Public Service Commission, or Commission.

Q. Mr. Duah, please state your current employer and business address.

A. I am employed by the Department. My business address is Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Duah, what is your position at the Department?

A. I am an Associate Utility Financial Analyst in the Office of Accounting, Audits and Finance.

Q. Please describe your educational background.

A. I received my Master’s Degree in Business Administration with a concentration in Finance and Accounting from State University of New York Institute of Technology in 2005.

Q. Please briefly describe your current responsibilities with the Department.

A. As an Associate Utility Financial Analyst, my assignments involve analyzing a company’s financial condition, capital structures, financing mechanisms, risks, costs of debt and equity, diversification, and the relative cost position/competitive position of utilities operating in New York State. My other assignments involve testifying in rate cases on financial issues, and special projects including the determination of allowed returns on equity for independent telephone companies in New York State.

Q. Have you previously testified in utility regulatory proceedings?

A. Yes, I have presented testimony in Commission cases concerning NYSEG/RG&E in Cases 09-E-0715, 09-G-0716, 09-E-0717, and 09-G-0718; Niagara Mohawk, Cases 08-G-0609,10-E-0500, 12-G-0202 and 12-E-0201; and Long Island Water, Case 11-W-0020.

Q. Are you sponsoring any exhibits?

A. Yes. We are sponsoring 12 exhibits identified as Exhibit___(SFPP-1) through Exhibit___(SFPP-12). Exhibit___(SFPP-1) contains interrogatory responses of Long Island Power Authority, which we will refer to as LIPA or the Authority and/or PSEG Long Island, which we will refer to as PSEG LI or the Company supporting our testimony.

SUMMARY

Q. What is the purpose of the Panel's testimony in this proceeding?

A. Our testimony will recommend a debt service requirement which should be used. As we will explain more fully in our testimony, the debt service requirement represents the principal payment, interest expense of the debt plus coverage requirements. We will address the financial benefits and risks associated with a municipal entity such as LIPA versus those of an investor-owned utility, which we will refer to as an IOU. We will also discuss the current financial condition of LIPA and how investors analyze its financial condition when making investment decisions. We will then discuss whether LIPA's goal of targeting a mid-"A" credit rating is an important objective in terms of minimizing cost to its ratepayers and we will develop the debt service requirement to be used in determining the rate year revenue requirements. Finally, we will discuss Staff's recommendation regarding the level of Pensions and Other Post Employment Benefits, which we will refer to as OPEBs, to include in PSEG LI's revenue requirement.

Q.

Q. What is the purpose of the Panel's revised testimony in this proceeding?

A. The purpose of our revised testimony is to provide updates and corrections to our pre-filed testimony to reflect the effect of swap payments, updated interest rate assumptions, and to revise our proposal with respect to Pensions and OPEBs.

Q. Please summarize the results of your revised testimony.

A. In its original prefiled testimony, Staff describes its methodology for estimating the interest rates for LIPA, future debt issuances and VRD. The methodology lowers the Authority's debt service payments and revenue requirements during the rate plan. Our revised testimony provides two updates and corrections to the adjustments resulting from the lower interest rate estimates. The first revision is to correct Staff's estimate of LIPA's debt service costs and swap payments that result from the outstanding VRD issues and the interest rate swap. This adjustment results in an increase to Staff's original revenue requirement recommendations in the amount of $23.285 million over the 3-year period. The $23.285 million increase consists of $3.673 million, $8.627 million, and $10.985 in rate years 1, 2, and 3 respectively. The second adjustment reflects lower anticipated interest earnings on LIPA's Operating and Rate Stabilization Funds. The lower earnings result in an increase in revenue requirement of $5.325 million, $10.012 million, and $12.450 million in rate years 1, 2, and 3 respectively, thus, a total of $27.787 million over the 3-year rate plan. The third revision, unrelated to interest expense, maintains LIPA's methodology with respect to Pensions and OPEBs and results in a higher anticipated debt service cost in the amount of $833,000 over the course of the three year rate plan.

Q. Please summarize your recommendations.

A. We recommend debt service requirements of $605.114 million, $634.526 million, and $680.865 million for Rate Years 1, 2, and 3, respectively, as opposed to PSEG LI’s revised request of $623.57 million, $681.24 million, and $742.40 million for Rate Years 1, 2, and 3 respectively. We recommend the same debt service coverage ratios excluding Utility Debt Securitization Authority Debt, which we will refer to as UDSA, requested by LIPA of 1.20x, 1.30x, and 1.40x and combined LIPA and coverage ratios including UDSA debt service of 1.10x, 1.15x, and 1.20x for Rate Years 1, 2, and 3, respectively, as requested by LIPA. In terms of revenue requirement, the debt service requirement accounts for approximately $18.455 million, $46.716 million, and $ 61.530 million in 2016, 2017, and 2018, respectively, of the difference between Staff and the Company’s proposed revenue requirements. The difference between our recommended debt service requirement and that of the Company is primarily the result of Staff’s recommended interest cost, Staff T&D Panel’s capital expenditure adjustment, and the Staff Energy Efficiency and REV Panel’s energy efficiency adjustment impact on debt service. Our recommended debt service requirement is summarized in Revised Exhibit___(SFPP-2).

Q. Please discuss the overall business structure of LIPA.

A. LIPA was originally created by the Long Island Power Act of 1985 to acquire the assets and securities of Long Island Lighting Company, which we will refer to as LILCO after the cancelation of the Shoreham Nuclear Power Plant. A wholly-owned subsidiary of LIPA acquired LILCO’s transmission and distribution system in May 1998. LIPA exists as a municipal subdivision of the State of New York and is responsible for the oversight and ownership of the former LILCO transmission and distribution system. As such, LIPA operates as a non-profit municipal electric utility.

Prior to January of 2014, LIPA operated under a service agreement with National Grid USA and played a more significant role in the day-to-day operation of the system than under the current agreement with PSEG LI. Under the current service agreement, PSEG LI has the primary responsibility for the day-to-day operations in the LIPA service territory. LIPA exists today, primarily, as the owner of the system and the holder of its debt.

Q. Please summarize the advantages of the combined structure of PSEG LI and LIPA.

A. The combined structure is intended to combine the operational efficiencies of PSEG LI with the financial advantages of LIPA’s municipal tax-exempt status. The combined structure, also, maintains LIPA’s access to Federal Emergency Management Authority, or FEMA, funding in the event of severe storms. FEMA funding is not available to IOUs and, as stated by LIPA witness Falcone at page 4 lines 4 - 5, has amounted to nearly $1.6 billion over the past five years. In addition, the structure allows LIPA to maintain rate-setting authority with statutorily mandated review and recommendation responsibility of the Department.

Q. What are the primary financial advantages of LIPA’s municipal tax-exempt status?

A. The major financial advantages of LIPA’s municipal tax-exempt status are as follows:

1. The authority to issue lower cost tax-exempt municipal debt.

2. The ability to finance without maintaining higher cost common equity in its capital base.
3. Not being required to pay federal or state income taxes.
4. The ability to obtain funding of storm related costs through FEMA.

Q. Please discuss the benefits of issuing tax-exempt debt.

A. Since the interest received by investors from LIPA's debt issuances are not subject to federal income taxes, investors will require lower returns on LIPA's debt than the taxable debt issued by private investor owned utilities. For example, if an investor required a 4% rate of interest on a taxable bond, and their marginal tax rate is 34%, a tax-exempt bond of similar risk should require an interest rate 2.64%, calculated as 4%x(1-.34). The savings of 1.36% multiplied by the amount of debt issued is a savings to the issuer.

Q. Please summarize the financial structure of a municipal owned utility, or MOU, as compared with that of an IOU.

A. IOUs are generally financed with a combination of debt and common equity. Alternatively, LIPA is financed with tax-exempt debt, grants, and internally generated funds.

Q. How do the financial structures influence the allocation of the operational and financial risks associated with IOUs and MOUs?

A. The owners of an IOU are the common equity investors and, as such, they bear the risks of ownership. An IOU typically maintains about 45% to 50% of its capital as equity. Alternatively, an MOU does not have equity investors and the ownership-related risks are borne by the bond holders, customers, and the municipal subdivision.

Q. Are there financial cost differences between the cost of common equity supporting IOUs and the debt capital supporting an MOU?

Q. Yes. The cost differences are twofold and can be very significant. First, the allocation of ownership risk to equity holders results in commensurate return requirements from those bearing the risks. That is, the cost of equity is generally paid for by customers through increased revenue requirements. Equity costs are substantial and currently range between 8.5% and 9.5%. Second, equity returns, or IOU profits, are subject to income taxes, which are also included in utility revenue requirements. The combination of providing revenues to fund equity returns and the related taxes, as well as the inability to issue tax-exempt debt, can result in a current incremental cost of capital of between 8.7% and 10.1% for an IOU. The current incremental cost of LIPA's capital is about 5% when debt service coverage requirements are included.

Q. Can the traditional risks borne by equity investors in an IOU be shifted to the debt holders in an MOU?

A. Yes, to some extent the risks can be shifted to municipal debt holders. But the risk-shifting is limited and results in an increase in the interest requirements of debt investors.

Q. How can a municipal revenue requirement be determined?

A. We are aware of four methods than can be used to determine the financial cost component of the revenue requirement for an MOU. These methods are 1) Rate of Return Method, 2) Cash Flow Method, 3) Times Interest Expense Ratio Method, and 4) Debt Service Coverage Method.

Q. Can you briefly describe these methods?

A. Yes. Capital cost recovery under the Rate of Return Method is typically based on the MOU’s weighted average cost of capital for the rate year. The cost of debt capital may be based on the weighted average cost for the rate year. Unlike the IOUs, the MOU’s cost of equity, referred to as owner’s equity or surplus capital, is typically based on the MOUs’ cost of incremental borrowing. The incremental cost of borrowing can be determined by the most recent bond yield average having the same credit ratings as the MOU’s. The bond yield averages are published in Mergent Bond Record, Moody’s Credit Perspective or similar publications. Some jurisdictions add some percentage to the yield average for municipal utilities under their jurisdiction while others do not.

Q. Please continue with a description of the Cash Flow Method.

A. An MOU may elect to use the Cash Flow Method for determining its capital recovery revenue requirements for a given rate year. Usually, an MOU’s reasonable cash needs may be categorized into five main areas. These are: a) debt service, including principal and interest for long-term and short-term debt, 2) funding of reserve requirements on both long-term and short-term debt as set forth in revenue bond and debt ordinances or adopted policies of the governing authority, c) annual payments for transfers to the municipality’s general fund at rates established by the MOU’s governing authority, d) capital lease payments and/or finance lease payments, e) annual payments to provide internally generated funds for construction, system improvements, and repair and replacement.

Q. Please describe the Times Interest Expense Ratio Method, or TIER.

A. This method sets a rate of return consistent with maintaining a reasonable level of interest expense coverage. As an illustration, if the dollar amount of an MOU’s debt service for its outstanding debt is $50 million, supporting a rate base of $20 billion, with an allowed 2.5x TIER, the rate of return commensurate with a TIER of 2.5 times applied to the $50 million debt service is 0.63%, calculated as 2.5x$50 million divided by the $20 billion rate base. The MOUs in some jurisdictions like Texas provide additional coverage of TIER. MOUs in Maryland have also been given the TIER option to determine their revenue requirement.

Q. Please describe the Debt Service Coverage Ratio Method, or DSCR.

A. In this method, the MOU first determines its debt service payments consisting of interest and principal payments. Once the debt service obligation is determined, a reasonable DSCR is applied to the fixed debt obligations to arrive at debt service and coverage requirement. The level of a utility's debt service coverage is the ratio of funds available to meet its debt service requirements, divided by the debt service requirements. For example, a DSCR of 1.50x reflects the ability of an MOU to meet 100% of its debt service obligations and have funds left over equal to 50% of its debt service requirements. Once the debt service requirement is determined, sources of funds other than the sale of electricity available to meet the requirement are subtracted to determine the amount of return that must be collected through revenue.

Q. How has Staff arrived at its recommended model for establishing rates for PSEG LI?

A. Staff’s recommendation regarding which model to use in establishing rates for PSEG LI is based upon two general principles. First, the model should provide a reasonable estimation of the cost of providing service to customers. Second, the model should result in an accurate financial representation of how investors view LIPA when making their investment decisions. This representation will allow for rates to be established that lead to financial results consistent with the goal of providing the lowest long-run cost of service to customers.

Q. Which model does the Department use when reviewing rates for IOUs?

A. The Department generally uses the Rate of Return

Model incorporating Generally Accepted Accounting Principles, or GAAP. For IOUs, this model meets both of the general principles described above. That is, it accurately represents the cost of service and is used by investors in making investment decisions.

Q. Which model is LIPA recommending be used in setting its rates?

A. LIPA is proposing to use the DSCR method to establish rates in this proceeding.

Q. Which method is used by the debt rating agencies when establishing debt ratings for LIPA?

A. The rating agencies use the DSCR method.

Q. Does the IOU rate of return model provide an accurate estimation of LIPA's cost of service and present an accurate representation of how investors view LIPA?

A. No, it does not. While the model will continue to provide an accurate estimate of LIPA's cost of service, it is not used by investors when making investment decisions for an MOU such as LIPA. As such, rating agencies will convert the rate of return results to the DSCR model when analyzing LIPA's financial condition.

Q. What is the potential implication of using a DSCR model to establish rates for LIPA?

A. The use of a DSCR model may produce intergenerational inequities. This can occur when the maturities of the financial vehicles financing the assets are longer or shorter than the useful life of the assets providing service. The result is that the liability amortization and debt maturities may not match the depreciation of the assets. This is relevant since it is the use of the assets, not the maturity of the liabilities that provide service to customers. Intergenerational inequities also occur when revenue requirements do not accurately match the generation of liabilities. For example, PSEG LI's funding proposal for Pensions and OPEBs will result in future customers paying for costs generated during this rate plan.

Q. Does the Cash Flow or TIER method alleviate the problems inherent with the DSCR?

A. No, they do not. Both methods have the same intergenerational equity issues. In addition, rating agencies do not use either method when evaluating MOUs. As a result, they are not useful for establishing rates for PSEG LI.

Q. What model is the Panel proposing to use to establish rates for PSEG LI?

A. Staff is recommending the use of a DSCR model. While its use may result in potential intergenerational inequities, the DSCR model will provide rate levels that we expect will result in LIPA maintaining access to debt markets at reasonable rates. Over the long-run, the access to debt markets that results from use of the DSCR model is expected to provide customers with a lower cost of service than the other methods would provide.

Q. Do you have any reservations about use of the DSCR method in this rate proposal?

A. While we do not have any significant reservations about the general way in which the basic methodological principles of the DSCR method are applied, we disagree with the interest rate assumptions used by LIPA.

Q. How does LIPA finance its cash flow requirements?

A. As previously discussed, LIPA is financed by a combination of municipal debt, internally generated funds, and grants. As such, the only outside financing available to LIPA is through the municipal tax-exempt debt markets. LIPA’s ability to issue debt, and the interest rate charged by investors and access to the debt markets are largely determined by LIPA’s bond rating.

Q. What are LIPA’s current bond ratings?

A. LIPA is currently rated “Baa1” by Moody’s Investor Service, or Moody’s, “A-” by Fitch, and “A-” by Standard and Poor’s, or S&P.

Q. How do LIPA’s ratings compare with the debt ratings of other major municipal electric utilities?

A. Exhibit___(SFPP-3) contains Moody’s 2014 Public Power Report of the public power industry. Page seven of the report lists the twenty largest public power utilities with generation ownership. As the report illustrates, LIPA’s Moody’s “Baa1” rating is below eighteen of the comparable MOU ratings; with only Puerto Rico Electric Power Authority rated lower than LIPA. The average Moody’s bond rating of the

Authorities other than LIPA is slightly lower than “Aa3”, or four notches above LIPA’s “Baa1” rating. The report also illustrates that LIPA’s 2013 debt service coverage of 1.19x is lower than all but two utilities and the 2013 debt ratio of 131% is the highest of any public utility company in the group.

Q. Please discuss the overall rating methodology employed by the rating agencies.

A. While each rating agency uses different qualitative and quantitative methodologies to assess the credit worthiness of LIPA, all three generally use a framework that measures the qualitative portion of their assessment based primarily upon a series of cash flow metrics. This methodology differs from the rating agency methodologies for IOUs that assess credit metrics generally using GAAP.

Q. How does GAAP accounting differ from using cash flow measurements?

A. The primary difference between GAAP accounting and the financial calculations used by rating agencies in assessing the credit worthiness of MOUs is that GAAP accounting allows for the deferral and amortization and accrual of expenses. Cash flow metrics, as contrasted with GAAP accounting, rely upon a cash centric analysis of municipal utilities.

Q. How does Moody's arrive at a "Baa1" debt rating for LIPA?

A. As detailed in Exhibit___(SFPP-4), Moody's uses a five factor analysis to arrive at its debt rating. It then weighs the result of each of the factors by a predetermined weighting to arrive at its overall rating. An explanation of its methodology is contained in Exhibit___(SFPP-4) and summarized below:

Rating Factor	Factor Weighting
1. Cost Recovery Framework Within Service Territory	25%
2. Willingness to recover Costs with Sound Financial Metrics	25%
3. Management of Generation Risks	10%
4. Competitive Risks	10%
5. Financial Strength (3 year average)	
a. Liquidity	10%

b. Leverage (Debt Ratio)	10%
c. Debt Coverage Ratio	10%
TOTAL	100%

Q. Please summarize Moody’s analysis of LIPA’s bond rating.

A Exhibit___(SFPP-5) contains Moody’s analysis of LIPA’s bond rating and is summarized as follows:

Rating Factor	Factor Score
1. Cost Recovery Framework Within Service Territory	Aa
2. Willingness to recover Costs with Sound Financial Metrics	Baa
3. Management of Generation Risks	A
4. Competitive Risks	A
5. Financial Strength (3 year average)	
a. Liquidity	Ba
b. Leverage (Debt Ratio)	Baa
c. Debt Coverage Ratio	Ba

The Moody’s report explaining the factor ratings and the overall analysis is contained in Exhibit___(SFPP-5).

As the exhibit illustrates, the metrics

evaluating LIPA’s financial strength are within the “Ba” to “Baa” range and do not support Moody’s current “Baa1” rating for the Company. As Exhibit___(SFPP-5) details, it is Moody’s view that the cost recovery framework and, in particular, the strength of LIPA’s service territory, LIPA’s management of its generation-related risks, and its competitive position, support the current “Baa1” bond rating. Based upon the above matrix and Moody’s scoring methodology, the indicative Moody’s rating for LIPA is “Baa2”. Moody’s has assigned its rating of “Baa1” based upon the belief that on a forward-looking basis, the average financial metrics and other credit considerations will improve to support an overall “Baa1” rating.

Q. How does S&P’s rating methodology differ from Moody’s?

A. While the S&P methodology is conceptually similar to Moody’s, it arrives at its rating using a somewhat different methodology. As detailed in Exhibit___(SFPP-6), S&P analyzes the following variables in deriving its rating for LIPA:

1. Management
2. Operations
3. Competitive position
4. Markets
5. Regulation
6. Service area economy
7. Finances
8. Legal Position

Q. Please summarize S&P’s rating conclusions.

A. As contained in Exhibit___(SFPP-7), in November 2014, S&P reaffirmed LIPA’s “A-” rating and placed LIPA’s rating on a negative outlook. A negative outlook means that a future downgrade is possible. The negative outlook is the result of the following S&P’s observations that:

1. While the securitization of LIPA’s debt is reducing the Company’s debt obligations and should improve debt service coverage and leverage ratios, it will not reduce customer’s bills. S&P states that the average consumer rates are high in absolute terms, the 2012 residential rates were about 8% above the State average, and its commercial rates are about 14% higher than

the State average. As a result, S&P believes the securitization will not improve LIPA's competitive position.

2. The legislation provisions enacted in 2013 introduced uncertain regulatory oversight.
3. The agreement to submit to a rate freeze could reduce LIPA's financial flexibility.
4. Financial credit metrics have been only barely adequate for an "A-" bond rating.

Q. Please summarize Fitch's rating methodology.

A. The Fitch report detailing its rating methodology is contained in Exhibit___(SFPP-8). As the Fitch report illustrates, the following five key drivers are analyzed in assigning it "A-" rating to LIPA:

1. Rate Sufficiency and Flexibility
2. Comprehensive Strategic Planning and Risk Management
3. Resource Adequacy and Performance
4. Financial Strength and Forecasting
5. Service Area Composition and Strength

Q. Please summarize Fitch's analysis of LIPA.

A. Fitch considers the following as key drivers in its analysis of LIPA:

1. The customer service territory is well diversified and exhibits above average wealth and income levels.
2. LIPA has solid utility fundamentals including an improved power supply mix and rate mechanisms to stabilize fuel and power purchase costs.
3. LIPA has weak debt metrics with $10.2 billion of debt and leverage of above 96%. Debt per customer was $9,173 for 2013 compared to the "A-" peer median of $3,403.
4. Concern over expanded regulatory oversight resulting from the 2013 Reform Act.

Q. In his testimony, Mr. Falcone discusses the importance of debt coverage ratios in the determination of debt ratings. Do you agree with Mr. Falcone's analysis?

A. Debt service coverage ratios are a key metric in the determination of debt ratings, however, as the above discussion illustrates, the rating agencies review a broad range of factors in their analysis.

Q. Do LIPA's debt ratios and credit metrics support the existing debt ratings?

A. No, the existing credit metrics do not support LIPA’s current bond ratings. It is the rating agencies’ qualitative assessments of LIPA that sustain its existing debt ratings.

Q. Will the proposed rate increases under either PSEG LI’s or Staff’s rate proposals result in credit metrics that support an “A” bond rating?

A. No. As illustrated in Exhibit___(SFPP-9), the pro forma credit metrics during the term of either rate plan will not support an “A” bond rating for LIPA.

Q. Is it the Panel’s opinion that an improvement in the credit metrics are necessary for LIPA to maintain and possibly improve its debt rating?

A. Yes. As demonstrated by the negative outlooks assigned to LIPA by both Fitch and S&P, LIPA’s existing rating of “A-” is under pressure. As detailed in the previously referenced Exhibit___(SFPP-5), Moody’s states that while it has assigned a “Baa1” rating to LIPA, its rating methodology produces a “Baa2” rating. The one notch upgrade is the result of expected improvement in LIPA’s credit metrics.

Q. What are the implications if LIPA is downgraded from its current debt ratings?

A. We have identified four potential impacts if LIPA is downgraded:

1. Increased interest costs of new debt borrowings.
2. Possible inability to refinance existing debt at lower interest rates over time.
3. Increases in future bank Letter of Credit costs or the possible inability to obtain future letters of credit.
4. An increase in the costs embedded in commodity contracts, including greater collateral posting.

Q. Has Staff quantified the potential increase in costs during the three year rate plan if LIPA is downgraded?

A. Yes, Staff has estimated the yearly impacts upon LIPA’s new debt service costs during the three rate years if LIPA is downgraded to “Baa2”/“BBB+”/“BBB+” during the rate year. If LIPA were to be downgraded to “Baa2”/“BBB+”/“BBB+” by Moody’s/S&P/Fitch ratings, respectively, during the rate year, absent the impact of Letters of Credit, or LOCs, bond administration costs, bank fees, and remarketing fees, our analysis, shown in Exhibit___(SFPP-10), indicates that the impact in terms of total debt service is at least $0.305 million, $1.555 million, and $3.242 million for RY1, RY2, RY3, respectively. In addition, through informal discussion with the Authority, LIPA has estimated $2.382 million increases in LOC costs, the loss of $625 million of an existing credit facility, loss of $85 million of unsecured credit supporting LIPA’s 2016 hedging program, and a loss of $300 million in subordinate commercial paper in late 2017. Taken together, LIPA has estimated a loss of $17.455 million, $40.176 million, and $46.847 million for 2016, 2017, and 2018 respectively if the company were to be downgraded one notch to “Baa2”/“BBB+”/“BBB+”.

Q. Given your recommendation, do you believe that a downgrade is a possibility during the rate plan?

A. While the possibility of a downgrade exists, we believe that the improved financial metrics combined with the existing qualitative assessments of LIPA will at least support the existing rating. In addition, the Delivery Service Adjustment Mechanism, which we refer to as the DSA, recommended by the DSA Panel provides protection to LIPA for variations in debt service costs, storm costs, and power supply costs. If adopted, the DSA will significantly reduce the operational and financial risk of the Authority.

Q. The Panel previously mentioned that it disagrees with the methodology used by LIPA to derive its interest rate assumptions. How has LIPA forecasted interest rates during the three-year rate period?

A. LIPA has relied on estimates by its consulting firm, Public Financial Management, or PFM, to estimate future interest rates for its long-term debt, Senior Commercial Paper, and Variable Rate Debt, or VRD, according to Mr. Falcone’s Exhibit___(TF-1). PFM has based its estimates upon forward interest rates. Moreover, PFM’s interest rate planning assumptions took into account the current interest rates, and “consensus of interest rate projections and expectations from a range of economists.”

Q. Based on these assumptions, what cost rates did PFM propose and LIPA ultimately use to determine the debt service requirement in this rate case?

A. For its planned long-term debt, LIPA employed 4.50%, 4.70%, 4.85%, and 5.00% cost rates for 2015, 2016, 2017, and 2018, respectively. For all of its Variable Rate and Commercial Paper debt instruments, except the 2014C VRD, LIPA used 0.375%, 1.10%, 2.00% and 2.50% interest rates for years 2015 to 2018, respectively. LIPA employed interest rates of 0.982%, 1.75%, 2.65%, and 3.15% for years 2015 to 2018 for its 2014C VRD based on 70 percent of 1-month LIBOR plus 65 basis points and interest rate expectations. Similarly, LIPA employed 0.750%, 1.45%, 2.325%, and 2.85% for its 2012D VRD for years 2015 to 2018, respectively. For the UDSA refunding debt, LIPA used the current yield curve and added 50 basis for the 2015 issuance and 75 basis points for the 2016 issuance.

Q. Does the Department use forward yield curve analyses and consensus interest rate projections and expectations to determine rate year interest costs of forecasted debt issuances for utilities?

A. No, it does not. The Department has recognized that the future interest rate curves and consensus interest rate projections are not accurate predictors of future interest rates and recognizes that current rates are the most accurate predictor of the costs of future debt issuances.

Q. Has LIPA previously used PFM estimates of future interest rates to forecast potential changes in rates?

A. Yes, LIPA has used similar PFM predictions of future interest rates in financial assumptions for budgeting purposes for each year since 2011. In response to IR DPS-TF-106, LIPA provided the PFM assumptions which are contained in our previously referenced Exhibit___(SFPP-1). As the Exhibit illustrates, the PFM forward interest rate assumptions have substantially overestimated rates in each forecasted year.

Q. What interest rate assumptions has Staff used in its analysis?

A. Our analysis uses the Department’s established methodology of current interest rates and estimates an interest rate of 4.12% for LIPA’s 2016, 2017, and 2018 planned long-term debt issuances for capital expenditure. For its 2012C and 2012D VRD and Senior CP we have determined an interest rate of 0.10%, 0.11%, and 0.19%, respectively, for the three rate years. For the 2014C VRD, we estimated its cost during the three rate years based on its current rate which is set at 70 percent of current 1-month LIBOR plus 65 basis points (as of April 27, 2015). Therefore, we have determined a 0.78% cost rate for the 2014C VRD. These current rates for the 2012C, 2012D VRD, 2014C, and Senior Commercial paper were provided by LIPA in response to information request DPS-TF-453 contained in our previously referenced Exhibit__(SFPP-1). For the UDSA debt, Staff is recommending that the current yield curve be used to estimate the debt service requirements.

Q. How did you derive the 4.12% cost of long-term debt for the new LIPA issuances?

A. The 4.12% cost of long-term debt is based on LIPA’s historical average bond yield spread above “Baa1”/“A-” public utility monthly average bond yields from January 2011 to present. We have calculated that spread to be 0.04%. As of March 31, 2015, Mergent Bond Record data shows an average bond yield for “Baa1”/“A-” public utility bonds of 4.08%. We have determined that the appropriate cost of long-term debt for LIPA’s new debt issuances for 2016 to 2018 is 4.12% (4.08%+0.04%). The derivation of our recommended cost of long-term debt is shown in Exhibit___(SFPP-11). The interest rates should be updated as this proceeding progresses.

Q. What interest costs is Staff recommending for the UDSA issuances?

A. Since the 2015 UDSA debt is anticipated to be issued prior to the decision in this proceeding, Staff is recommending that the actual interest costs of the 2015 issue be used for establishing rates. Consistent with Staff’s recommendations for establishing rates for LIPA’s planned debt, Staff is recommending that the current yield curve be used for the 2016 UDSA issuances. Given that LIPA estimated UDSA’s 2016 yield by adding 75 basis points to the current UDSA’s debt yield, Staff has subtracted the 75 basis points from the 2016 yield curve projected by LIPA to arrive at the current rates.

Q. What is the overall impact of Staff’s interest rate assumptions on PSEG LI’s revenue requirements?

A. Staff’s interest rate assumptions reduce the debt service costs for LIPA by $10.65 million, $25.64 million, and $39.85 million in 2016, 2017, and 2018 respectively. Staff’s projected debt service costs for the 2016 UDSA debt issuances results in an additional reduction in debt service costs of $5.426 million in 2016, $15.949 million in 2017, and $15.155 million in 2018.

Q. Please discuss your adjustment relating to the two outstanding VRD issues.

A. LIPA has a series of variable interest rate bonds outstanding that total $674 million. The interest rates on the VRD bonds are established based upon a variety of interest rate indices. Concurrently, LIPA has an outstanding interest rate swap agreement on debt valued at $587.225 million. The swap relates to a separate financial instrument that requires LIPA to make a fixed payment of 5.12% on the $587.225 million balance. LIPA, in return, receives 69.47% of 1-month LIBOR multiplied by the $587.225 million. The swap effectively hedges $587.225 million of the $674 million variable rate exposure. The interest payments associated with the remaining $86.775 million of VRD are not matched to the swap payments and float un-hedged with their respective indices. While the Authority projected an increase in interest rates during the rate plan, Staff estimated the future interest rates based upon the current market environment. As discussed in the Panel’s testimony on page 31, lines 4 through 15, Staff’s forecast methodology is consistent with the Department’s interest rate estimation methodology.

Staff’s pre-filed testimony, however, did not accurately match the VRD debt to the corresponding swap hedge. The Panel’s revised testimony more accurately estimates the interaction between the swap payments and the outstanding VRD interest payments by more closely linking the swap payments and the VRD interest payments to their respective comparable indices.

Q. Please discuss your adjustment to the interest earnings relating to LIPA's Operating and Rate Stabilization Funds.

A. LIPA's Operating Expense and Rate Stabilization Funds are accounts that were created under the Authority's General Revenue and Bond Resolution. The Operating Expense Fund is a general account holding Authority funds available to pay operating expenses prior to the application of funds to pay debt service or PILOT payments. The Rate Stabilization Fund is a reserve account available for any lawful purpose of the Authority, including payment of expenses and debt service. Some of the bank agreements require a minimum balance of $150 million in the Rate Stabilization Fund. Failing to replenish the minimum balance could result in the early termination of those bank agreements. Both funds invest in short term high grade investments earning market determined interest rates. A review of Staff's interest earnings assumptions indicates that in its initial calculation, Staff overestimated the earnings of both funds under its forecasted interest rate assumptions. As a result, our revised testimony lowers the interest rate adjustments consistent with Staff's lower interest rate estimates. This adjustment raises the revenue requirement by $5.325 million, $10.012 million, and $12.45 million in rate years 1, 2, and 3 respectively.

Q. Does Staff propose updating the interest expenses, swap payments, and interest earnings estimates?

A. Yes. The interest rate assumptions in our testimony should be updated as this proceeding progresses. Any difference between debt service expenses, swap payments, and interest earnings from those approved in the proceeding are expected to be captured by the Delivery Service Adjustment over the course of the rate plan.

Pension and Other Post Employment Benefit Funding

Q. Please discuss PSEG LI's revised proposal for funding Pension and OPEBs requirements.

A. PSEG LI is proposing to include only the minimum Employee Retirement Income Security Act, or ERISA, funding requirements in revenues, instead of the projected GAAP costs. The difference between the ERISA and GAAP cost estimates would be deposited only after debt service has been paid.

Q. Please discuss the financial implications of PSEG LI’s Pension/OPEBs funding request.

A. PSEG LI is projecting $220.7 million of Pension and OPEB costs during the term of the three-year rate plan and has included only $52.4 million of those costs in its revenue requirements. PSEG LI has proposed to finance the shortfall of $56.1 million, $56.3 million, and 55.8 million in 2016, 2017, and 2018, respectively.

Q. Has PSEG LI presented a plan for eventually charging customers for the full GAAP costs been presented?

A. No, PSEG LI has not presented a plan to eventually charge customers the full GAAP cost.

Q. What are the financial implications of the Pension and OPEB funding contained in PSEG LI’s rate proposal?

A. LIPA believes that the rating agencies will only include the ERISA requirements in the calculation of LIPA’s financial metrics. This interpretation is based upon the ability to fund the difference between the GAAP and ERISA costs after the payment of its debt service costs. While the rating agencies interpretation of LIPAs position is uncertain, their agreement with LIPA’s position would result in minimal impact on its debt coverage ratios. This occurs since only the financing costs of the additional debt funding the shortfall will impact the financial metrics. The yearly financing costs are estimated to be approximately $4.5 million, $8.9 million, and $15.5 million in 2016, 2017, and 2018, respectively. The financing costs will continue to increase as the costs recovery continues to be deferred. If the rating agencies disagree with LIPA’s interpretation, the debt service coverage would be reduced by about 0.07x in each year. This would continue each year until the GAAP requirements are fully funded.

Q. What are the financial implications of LIPA’s position?

A. While there are short-term beneficial rate impacts of deferring the cost recovery, the long-run financial impact will be a decrease in the financial profile of the Authority. This decrease will result from overall reduced financial metrics due to the additional debt burden.

Q.   What is Staff's revised proposal for funding Pension and OPEB costs?

A.   To mitigate the effect of the proposed rate increase on customers, Staff is proposing to maintain unchanged the treatment of Pensions and OPEBs currently utilized by LIPA. Implementation of Department policy to Pensions and OPEBS, which bases the amount allowed in rates for pensions and OPEBs on the amounts of those benefits that employees earn during the rate year based on actuarial estimates rather than on the cash payments made by the utility for the benefits during the rate year, will not be recommended at this time. Staff revised pension and OPEBs proposal results in an increase in debt service cost of $87,700, $110,000, and $630,000 in rate years 1, 2, and 3 respectively. The cumulative total increase in debt service costs during the rate plan is

$833,000.

Q. Does this conclude your testimony?

A. Yes it does, at this time.

JUDGE PHILLIPS: The next one entered by affidavit will be the PSEG Sales Revenue Panel. Is it original and rebuttal; is that correct?

MR. WEISSMAN: Correct, Your Honor. The Sales and Revenue Forecasting direct testimony is being sworn to by Mr. Irrgang and Mr. Karol. It's a document that was filed on January 30, 2015 consisting of 29 pages with nine exhibits. Those exhibits are identified on the list provided as Exhibit 49. It's a one-page exhibit. Exhibit 50, is also a one-page document. Exhibit 51 is a one-page document. Exhibit 52, 53, 54 and 55, those are all one-page exhibits I believe identified as SRFP 1 through 7.

There is also SRFP 8, a three-page exhibit and SRFP 9 which is a six-page exhibit. 8 is Exhibit 56 and 9 is Exhibit number 57. I have spoken with Mr. Favreau briefly. Exhibit 58, Your Honors, working with the list that we provided, I believe there was an error on that list I just want to point out. Exhibit 58 is a revision of SRFP 9 that was submitted. The witness identified a display error in his original exhibit; no changes to any of the figures that we used in our revenue requirement or anywhere else. It was simply a display error. That has been identified as Exhibit 58.

The DMM number is 110, not number 1 that is shown on the list that I have. That was submitted yesterday I believe to DMM, not on January 30th. That is the revised Exhibit 9. That is SRFP 9. Mr. Karol and Mr. Irrgang were available to bring that up. On the Rebuttal Testimony on Sales and Revenue Forecasting was actually only submitted by Mr. Irrgang. That is an eighteen-page document with five exhibits.

Those exhibits are identified as Exhibits Numbers 59 through 63. Exhibits 59 through 62 are all one-page documents. Exhibit 63 is an eleven-page document. They are all associated with the rebuttal testimony of Mr. Irrgang, that eighteen-page document with five exhibits. I can bring those affidavits to you now (handing).

JUDGE PHILLIPS: We are just noting that we are going to reserve the Exhibit 109 for the affidavit concerning the Sales and Revenue Forecasting Panel. It needs to be updated to reflect the correction that was stated on the record by Mr. Weissman with respect to the revision of one of the exhibits. We will have a placeholder with the corrected affidavit hopefully tomorrow.

Provisionally it is marked for identification as 109. The affidavit adopting Mr. Irrgang's Rebuttal Testimony has been marked for identification as 110. I would like to note for the court reporter that the Pre-filed Testimony of the Sales and Revenue Forecasting Panel, Mr. Irrgang and Mr. Karol, should be copied into the record followed by the Rebuttal Testimony by Mr. Irrgang copied into the record as though given orally.

Thank you.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan　　　　Case 15-____________

DIRECT PRE-FILED TESTIMONY OF THE SALES AND REVENUE FORECASTING PANEL

Date: January 30, 2015

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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Sales and Revenue Forecasting Panel (the "Panel").

A. We are Bryan Irrgang and Robert Karol.

Q. Mr. Irrgang, please state your employer and business address.

A. I am employed by PSEG Long Island LLC ("PSEG LI" or the "Company") and my business address is 175 East Old Country Road, Hicksville, NY 11801.

Q. In what capacity are you employed by the Company?

A. I am employed by the Company as Manager of Electric Load Forecasting.

Q. Please summarize your educational background and professional experience.

A. I have been employed in the energy industry for over 35 years. I was previously employed by MacLeod & Steward for ten years, then by The Long Island Lighting Company ("LILCO") for eight years, then by KeySpan for nine years and then by National Grid for six years. In 2014 I assumed my current position with PSEG LI. I have been performing electric load forecasting on Long Island for 18 years under LILCO, KeySpan, National Grid and PSEG LI. Additionally I am currently serving in my 6th consecutive year as chair of the New York Independent System Operator's ("NYISO") Joint Load Forecasting Task Force and have been a task force member for 11 years.

I received an Associate of Science degree in Engineering Science from the College at Farmingdale, SUNY; a Bachelor of Science degree in Mathematics from the SUNY College at Old Westbury and a Master of Science degree in Applied Mathematics and Statistics from Stony Brook University.

Q. Robert Karol, please state your employer and business address.

A. I am employed by PSEG LI and my business address is 175 E Old Country Road, Hicksville, New York 11801.

Q. In what capacity are you employed by the Company?

A. I am employed by the Company as Lead Analyst, Revenue Analytics Regulation and Pricing.

Q. Please summarize your educational background and professional experience.

A. In 1991, I joined LILCO and spent six years as an Industrial Engineer in the Gas Operations Department. Before the Brooklyn Union Gas Company – LILCO merger that formed KeySpan, I moved to Corporate Planning where I worked on various mergers and acquisitions ("M&A") activities and performed financial analysis for diversified projects. Subsequently, I became Manager of Financial Analysis in KeySpan's unregulated Energy Development subsidiary. In 2004, I accepted a position as Lead Analyst in the Forecasting group in KeySpan's electric Business Unit. KeySpan subsequently was acquired by National Grid. This group was responsible for the Revenue Analysis function on behalf of the Long Island Power Authority ("LIPA"). I was responsible for maintaining the models that forecast LIPA's revenues and for analyzing monthly variances. Essentially, this same position was reorganized into my current position in the Regulation and Pricing group when PSEG LI became the service provider for the LIPA contract as of January 1, 2014.

I hold a Master in Business Administration degree from Pace University and a Bachelor of Science degree in Industrial Engineering from the Pennsylvania State University.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to present the Company's electric sales and customer forecasts used to support the revenue requirement presented in this filing.

Q. Are you sponsoring any exhibits in support of your testimony?

A. Yes. We are sponsoring the following exhibits, which were prepared by us or under our direction and supervision:

Exhibit __ (SRFP-1)	-	Annual Residential and Commercial & Industrial Sales per Customer Models: Statistical Results
Exhibit __ (SRFP-2)	-	Residential and Commercial & Industrial Sales Forecast
Exhibit __ (SRFP-3)	-	Other Sales Forecast
Exhibit __ (SRFP-4)	-	Sales Forecast Reductions for Energy Efficiency & Renewables and Cogeneration
Exhibit __ (SRFP-5)	-	System Sales Forecast
Exhibit __ (SRFP-6)	-	Sales Forecast Assumptions
Exhibit __ (SRFP-7)	-	Residential and Commercial & Industrial Customer Forecast
Exhibit __ (SRFP-8)	-	Sales Forecast Input to Revenue Model - Sector Sales Forecast
Exhibit __ (SRFP-9)	-	Forecast Revenues by Rate Categories

II. <u>ELECTRIC SALES FORECAST</u>

Q. Please give a high level description of your electric sales forecast.

A. We are projecting modest average annual growth in electricity sales for LIPA of 0.3% during the years 2016 through 2018 resulting from the combination of moderate forecast growth for the Long Island economy, slow projected population growth and aggressive energy efficiency and renewable programs. Please allow me to give some context. LIPA sales achieved average annual growth of 1.9% for the ten years ending in 2007, which was a period of robust expansion for the Long Island economy characterized by advances in employment, household income and home prices. Conversely, LIPA sales declined at an average annual rate of 0.4% for the five years ending in 2013, coinciding with a contraction in the Long Island economy characterized by flat employment and household income and falling home prices. For the period 2016 through 2018, our sales projections assumed mixed results characterized by growth in employment and household income but continuing weakness in home prices, which would produce a moderate expansion of the Long Island economy. We have based our underlying economic assumptions on data provided by Moody's analysts. Additionally, the continuation of the recent trend on Long Island toward slower growth in population and new household formations, with correspondingly slow growth in residential and commercial industrial customers, anticipated for the years 2016 through 2018 would further constrain growth in electricity sales. Finally, aggressive energy efficiency and renewable programs which have contributed to the reductions in electricity use per customer experienced recently – a phenomenon particularly noticeable in the residential sector – are likely to constrain sales growth in 2016 through 2018.

Q. Please explain how the Panel forecasted electric sales?

A. The Panel forecasted residential and commercial & industrial electric sales using econometric modeling.

Q. Did the Panel use econometric modeling to forecast all of its electric sales?

A. No. As will be explained later in this testimony, econometric modeling was used to forecast residential and commercial & industrial electric sales only, which together comprise about 97 percent of LIPA's total annual sales. PSEG LI employs other methodologies to forecast the remaining three percent of electric sales relating to other public authorities, street lighting and electric vehicles.

Q. What is econometric modeling?

A. Econometric modeling is a technique used to estimate economic relationships based on historical data which are then used to make predictions under a set of assumed economic conditions. Econometric models are empirically derived mathematical equations that specify the statistical relationship between independent (or explanatory) variables and the dependent variable.

Q. Are econometric models frequently used to forecast electric sales?

A. Yes, all of New York's major electric utilities employ some form of econometric modeling to forecast all or a portion of their electric sales.

Q. Did you use computer software to calculate the relationship between electric use and the explanatory variables?

A. Yes, PSEG LI utilizes Statistical Analysis System ("SAS") software to run its econometric models. SAS is a software suite developed by the SAS Institute for advanced analytics, business intelligence, data management, and predictive analytics. The SAS software is widely used for advanced analytics.

III. RESIDENTIAL ELECTRIC SALES FORECAST

Q. Mr. Irrgang, please discuss the residential model.

A. The model development process began with the identification of those explanatory variables considered relevant in explaining the dependent variable, e.g., residential sales per residential customer (use per customer). Next, multiple combinations of the independent variables were tested using regression analysis to arrive at a satisfactory model. As seen in rows 3 through 9 on Exhibit ___ (SRFP-1), the statistical results show that the equation fits the data well. For the independent variables all of the t-values are at least 1.96, except one, which is only slightly below. A t-value of 1.96 indicates that the particular variable is statistically significant with 95% confidence. The residential model specification resulted in an Adjusted R^2 of 98.55%, which indicates the percentage of variation in the dependent variable that is explained by the independent variables is considerable.

Q. Why did the Company specify "electric use per customer" instead of sales as the dependent variable for the residential model?

A. The Company specified "use per customer" because it more accurately accounts for growth in the market. A simple example is to consider a regression model that uses residential electricity sales for the past 30 years as the dependent variable and includes annual cooling degree days ("CDD") among the independent variables. Using such a model, one can estimate the impact that an extra 100 CDDs (out of about 1,294 CDDs in an average year) will have on sales and it will be the same for each year modeled. This is an obvious problem since the number of LIPA's residential customers has increased by nearly 20% over the past 30 years, meaning the sales impact should be relatively larger for the more recent years. However, if the dependent variable is electricity use per residential customer, then the estimate of the impact of an extra 100 CDD from the model will again be the same for each year modeled; however this value will be multiplied by the number of customers for each year and so would be 20% greater for the most recent year compared to the earliest year. This approach gives a more accurate estimate of the sales impact for any given year.

Q. What is the source of the data used to construct the use per customer variable for the residential model?

A. The electric sales and customer levels for the residential sector were obtained from the customer billing system.

Q. Please describe the explanatory or independent variables the Company used to develop its residential electric sales forecast.

A. As shown in rows 3 through 9 on Exhibit __ (SRFP-1), PSEG LI's current model specification utilized six independent or explanatory variables to forecast its residential electric sales per customer: 1) cooling degree days; 2) the ratio of employees to residential customers; 3) median real home price; 4) annual average real price of electricity; 5) real regional income per customer; and 6) real gross metro product per customer. Again the dependent variable is use per customer.

Q. What was the historical data set you used to construct the residential electric sales per customer model?

A. Annual historical data from the past 30 years was used.

Q. Please describe the variable "cooling degree day."

A. CDD is a weather variable that is used to measure conditions above a fixed reference level, called the base. For example, the National Weather Service calculates CDDs as the number of degrees (°F) that the average temperature for a day (the average of the daily maximum plus minimum temperatures) exceeds a base of 65°F. However, there are alternative definitions of CDDs that are commonly used in the utility industry. PSEG LI calculates cooling degree days as the number of degrees that the average Temperature-Humidity-Index ("THI") for a day (the average of the 24 hourly THI values) exceeds a base of 60 degrees. CDDs are used during warm weather to estimate the energy needed to cool indoor air to a comfortable temperature. Higher values indicate warm weather and the need for higher energy demands for cooling. The residential electric sales forecast is based on normal weather conditions where the normal weather is determined by a 30-year average of annual CDDs.

Q. Where did the CDD variable come from?

A. CCDs were prepared internally based on information purchased initially from the National Weather Service and more recently from a commercial vendor (Schnieder Electric) for the Central Park Weather Station.

Q. Could data from a weather station on Long Island be used?

A. National Weather Service data is currently available for several Long Island airport weather stations but the available history was insufficient to develop 30-year normal weather.

Q. Why didn't the Panel also use heating degree days ("HDD") as a variable in the residential model?

A. We tested HDD in the model, but it was determined not to be a significant variable and thus was excluded. There simply are not enough customers with electric heat in our service territory to make HDD a significant variable.

Q. What is the "ratio of employees to residential customers" variable?

A. The ratio of employees to customers variable is the number of people employed on Long Island divided by the number of residential customers served by the Company. What we have found is that as the ratio increases, it indicates fewer people are remaining at home and therefore electricity use in the home decreases.

Q. What is your source for the employment data?

A. We obtain the employment statistics from the U.S. Department of Labor, Bureau of Labor Statistics. The Bureau of Labor Statistics is the principal Federal agency responsible for measuring labor market activity, working conditions, and price changes in the economy. Its mission is to collect, analyze, and disseminate essential economic information to support public and private decision-making. PSEG LI is able to obtain employment information specific to its service territory from the Bureau of Labor Statistics.

Q. What is the "median real home price" variable?

A. The "median real home price" variable is the median selling price of existing single family homes in our service territory adjusted for inflation using a local Consumer Price Index ("CPI").

Q. What is your data source for the median home price in the Company's service territory?

A. All of our economic data, including median home price, is provided to us by our consultant, Moody's Analytics.

Q. What is Moody's Analytics?

A. Through its team of economists, Moody's Analytics is a leading independent provider of data, analysis, modeling and forecasts on national and regional economies, financial markets, and credit risk. Moody's Analytics tracks and analyzes trends in consumer credit and spending, output and income, mortgage activity, population, central bank behavior, and prices. It provides concise and timely reports and one of the largest assembled financial, economic and demographic databases, which supports firms and policymakers in strategic planning, product and sales forecasting, credit risk and sensitivity management, and investment research. Its products are used by more than 800 major corporations worldwide, representing a broad range of industries including banking, government, asset management, real estate, utilities, and retail. Major New York utilities, the NYISO, ISO New England, and numerous federal government bodies all use data from Moody's Analytics.

Q. What is the "real income per customer" variable?

A. This variable refers to the regional income for Long Island divided by the number of our residential customers, as adjusted for inflation using the local CPI. We found that for this variable the two year average value of the current year and one year prior works best in the model. The regional income series is obtained from Moody's Analytics.

Q. What is the "real gross metro product per customer" variable?

A. This variable refers to value of all the goods and services produced on Long Island divided by the number of our residential customers, as adjusted for inflation using the GDP implicit price deflator. The gross metro product series is obtained from Moody's Analytics.

Q. What did you mean when you referred to the "annual average real price of electricity" variable?

A. This refers to the annual average price of electricity that our customers actually paid, adjusted for inflation using the local CPI. We obtain this information directly from the Company billing system. Again we have found that for this variable the two-year average value of the current year and one year prior works best in the model.

Q. Why did you use annual data for the residential model?

A. Simply put, it is to minimize the degree of estimation and to maximize the degree of uniformity in the data used to develop the residential model, which I will explain. The dependent variable, use per customer, could be constructed using the residential sales reported in the billing system each month. However, there is some disadvantage with that approach. About 25% of the residential customers are billed for 30 days of electric consumption calculated from one actual meter read and one estimated meter read, introducing a mean absolute percent error of 0.73% of the total billed sales reported each month. The growth in residential sales has only averaged 0.25% per month for the past decade and so is easily overwhelmed by the 0.73% error introduced through estimated meter reads. Furthermore, of the total customers represented in the billed sales for any given month, 87% are from that half of the customers that are in the current month meter read group while the remaining 13% are from the other half of customers that are in the prior month meter read group and those proportions alternate in subsequent months, meaning the two mutually exclusive customer groups are not uniformly represented in the monthly observations. If the period under observation is increased from monthly to quarterly the error introduced through estimated meter reads is only 0.18%, smaller than the 0.75% average growth for the past forty quarters. However, 63% of the total customers represented in the billed sales reported quarterly have their meters read during the first and third months while the remaining 37% have their meters read during the second month and again those proportions alternate in subsequent quarters so the lack of uniformly represented in the observations remains an issue. Additionally, there are calendar differences that further reduce uniformity in quarterly observations. If the period under observation is increased to annual, the error introduced through estimated meter reads is only 0.06%, which is more than an order of magnitude smaller than the 3.0% average growth for the past ten years. Also, the two mutually exclusive customer groups are equally represented in the billed sales reported annually, establishing uniformity in the observations. Finally, the calendars are the same for annual observations (with the exception of Leap Days which are adjusted manually) so uniformity is maintained.

Q. Mr. Irrgang, please discuss the sources for the assumptions used in the residential electric sales forecast.

A. The assumptions represent the projected values of the independent variables for 2014 through 2018 as used in the residential use per customer model. Most of the assumptions were provided by Moody's Analytics with the exception of normal cooling degree days, residential customers and the residential price of electricity which were developed internally. In particular, the electricity price assumptions represent preliminary values since the sales forecast is developed at an early stage in the overall process, before sales forecast results are available to establish more refined price values. The use of preliminary price projections in econometric modeling is acceptable because of the relative price inelasticity of electric consumption. All of the variables used to create the assumptions for the residential sales forecast are shown on Exhibit ___ (SRFP-6) except for the residential customer forecast which is shown in rows 4 through 8 for column 2 on Exhibit ___ (SRFP-7).

Q. Mr. Irrgang, did you make any out-of-model adjustments to the residential electric sales forecast?

A. Yes.

Q. Why are out-of-model adjustments necessary?

A. Out-of-model adjustments are necessary because certain factors or variables will impact projected sales but cannot be adequately accounted for in the model.

Q. What out-of-model adjustment was made to your residential electric sales forecast?

A. We adjusted the residential sales forecast to account for demand side management ("DSM") initiatives. Reductions in load due to DSM are not a function of local economic conditions (as sales are) but rather represent PSEG LI's deliberate efforts to constrain load growth for purposes of system reliability, operational efficiency and to further New York State public policy goals. Thus an out-of-model adjustment is needed to account for the anticipated reductions due to DSM.

Q. What is DSM?

A. DSM involves reducing electricity use through activities or programs that promote electric energy efficiency or conservation, or more efficient management of electric energy loads.

Q. What programs were considered by PSEG LI when calculating its DSM reduction to the residential sales forecast?

A. The DSM reduction is composed of PSEG LI's existing Energy Efficiency and Renewable Energy programs. These programs are discussed in detail in the direct pre-filed testimony of the Utility 2.0 and Energy Efficiency Panel.

Q. What were the overall forecasted reductions to the residential electric sales forecast resulting from DSM?

A. Exhibit __ (SRFP-4), among other things, summarizes the total DSM reductions to the residential electric sales forecast. As set forth in column 2 of the exhibit, the DSM reductions to the residential electric sales forecast are: 270.0 gigawatt hours ("GWh") for 2015; 444.4 GWh for 2016; 623.0 GWh for 2017; and 787.4 GWh for 2018.

Q. Mr. Irrgang, please summarize the total residential electric sales forecast.

A. Referring to Exhibit __ (SRFP-2), column 2, the projected customers in rows 4 through 8 are multiplied by the model predicted use per customer values in rows 11 through 15, resulting in the calculated sales shown in rows 18 through 22. Next, the calculated sales are calibrated to the projected year-end sales for the current year as shown in rows 25 through 29. Finally the sales reductions shown in rows 32 through 36 are subtracted from the calibrated sales, resulting in the sales forecast shown in rows 39 through 43. In summary, as shown in rows 10 through 13 of columns 2 and 6 on Exhibit __ (SRFP-5), the Panel is forecasting residential electric sales growth rates (after accounting for reductions due to the DSM out-of-model adjustment) of: 0.34% (32.8 GWh) for 2015; -0.22% (-21.1 GWh) for 2016; -0.93% (-88.9 GWh) for 2017; and -0.38% (-35.9 GWh) for 2018. After adjusting for leap years as shown in rows 16 through 19 of columns 2 and 6 on the exhibit, the growth rates are: 0.34% (32.8 GWh) for 2015; -0.49% (-47.1 GWh) for 2016; -0.66% (-62.8 GWh) for 2017; and -0.38% (-35.9 GWh) for 2018.

IV. COMMERCIAL & INDUSTRIAL ELECTRIC SALES FORECAST

Q. Mr. Irrgang, did the Panel use econometric modeling to forecast the Company's commercial & industrial electric sales?

A. Yes. The commercial & industrial electric sales forecast was developed using econometric models very similar to the one used to forecast the Company's residential electric sales.

Q. Please describe the econometric models used to develop the commercial & industrial electric sales forecast.

A. The Panel modeled the following eight distinct segments or sectors for Long Island to forecast its commercial & industrial electric sales: manufacturing ("MFG"); trade, transportation and utilities ("TTU"); leisure and hospitality ("LEI"); financial activities ("FIN"); information ("INFO"); business services ("SER"); education and health services ("EHS"); and government ("GOV"). The Panel developed econometric models for each of these sectors to produce the overall commercial & industrial electric sales forecast.

Q. Please discuss the eight commercial & industrial models.

A. As shown in rows 10 through 46 on Exhibit __ (SRFP-1), the statistical results show that the equations fit the data well. Specifically, except for two intercept terms and two of the independent variables, the t-Values are all at least 1.96 indicating statistical significance with 95% confidence. The model specifications resulted in Adjusted R^2 that indicate the percentage of variation in the dependent variables explained by the independent variables is again considerable: three models are above 90% and all the rest are at least 85% except one, the FIN which is an acceptable value of 82.65%.

Q. Were the variables the same for each sector?

A. The dependent variable for each sector model was electricity use per customer. The explanatory or independent variables, however, tended to differ for each sector model as shown in rows 10 through 46 of the specifications on Exhibit __ (SRFP-1).

Q. Please describe the independent variables for the MFG sector.

A. The independent variables for the MFG sector were MFG employment per MFG customer until 1988 and MFG employment per MFG customer after 1988.

Q. Explain the MFG employment per MFG customer variables used in the model?

A. We found that the change in electricity use in response to changes in the ratio of MFG employment to MFG customers was different for the periods up to 1988 and then after 1988 – it had increased over time. We isolated the response by using two variables. The first, MFG employment per MFG customer until 1988 has a value of 0 after 1988 while the second, MFG employment per MFG customer after 1988 has a value of 0 before 1988.

Q. What were the variables for the TTU sector?

A. There were two variables: real regional income per TTU customer until 2005 and real regional income per TTU customer after 2005.

Q. Please describe the explanatory variables for the LEI sector.

A. There were seven explanatory variables for this sector: HDD; CDD; real LEI GMP per LEI employee; a category or "dummy" variable for the years 1984-1985; real electric price; real regional income per LEI customer; and the ratio of households in the service territory to LEI customers.

Q. What is a category or "dummy" variable?

A. In statistics and econometrics, a dummy variable is one that takes the value 0 when the condition is not present and a fixed value when the condition is present. Dummy variables do not represent any underlying trends and are used to account for anomalies in the historic data set. Dummy variables therefore accommodate a specific set of data points to reduce model error.

Q. What is the LEI GMP?

A. GMP is one of several measures of the size of the economy of a metropolitan area. Similar to gross domestic product, GMP is the market value of all final goods and services produced within a metropolitan area in a given period. LEI GMP is simply a further refinement of the GMP for the Long Island metropolitan area that only applies to the LEI sector.

Q. What were the independent variables for the FIN sector?

A. There were five: CDD; real Long Island GMP per FIN customer; a dummy variable for years 1992-1994; another dummy variable for the years 2009-2012 and real income per household (two-year average).

Q. Please describe the independent variables for the INFO sector.

A. The econometric model for the INFO sector included three independent variables: INFO employment per INFO customer; real electric price (two-year average) and a dummy variable for the years 1986-1991.

Q. What were the independent variables for the SER category?

A. The independent variables for this category were SER employment per SER customer; real electric price (two-year average) and a "before 1992" dummy variable.

Q. Please describe the independent variables for the EHS sector.

A. The EHS sector econometric model included three variables: Real Income per household (two-year average); the difference in rates between the ten-year Treasury Note and the three-month Treasury Bill (two-year average) and a "before 1992" dummy variable.

Q. Finally, what were the explanatory variables for the GOV sector?

A. The independent variables for the GOV sector included: GOV employment per GOV customer until 1998; GOV employment per GOV customer after 1998; real electric price; and a "before 1992" dummy variable.

Q. Mr. Irrgang, please discuss the sources of the assumptions used in the commercial & industrial electric sales forecast.

A. Most of the assumptions were provided by Moody's Analytics with the exception of normal cooling and heating degree days, commercial & industrial customers and the commercial & industrial price of electricity which were developed internally. All of the variables used to create the assumptions for the commercial & industrial sales forecast are shown on Exhibit __ (SRFP-6) except for the commercial & industrial customer forecast which is shown in rows 4 through 8 on Exhibit __ (SRFP-7).

Q. Mr. Irrgang, were any out-of-model adjustments made to the commercial & industrial electric sales forecast?

A. Yes, we reduced the commercial & industrial forecast to account for DSM programs.

Q. What programs were considered by PSEG LI when calculating its DSM reduction to its commercial & industrial electric sales forecast?

A. As was the case for the residential forecast, the DSM reduction for the commercial & industrial sales forecast is composed of PSEG LI's existing energy efficiency, renewables and demand response programs. These programs are also discussed in detail in the direct pre-filed testimony of the Utility 2.0 and Energy Efficiency Panel.

Q. What were the overall forecasted reductions to the commercial & industrial electric sales forecast resulting from DSM?

A. Please refer to Exhibit __ (SRFP-4). As set forth therein, the DSM reductions to the commercial & industrial electric sales forecast are: 224.7 GWh for 2015; 359.8 GWh for 2016; 496.0 GWh for 2017; and 625.1 GWh for 2018.

Q. Were there any other out-of-model adjustments made to the commercial & industrial electric sales forecast?

A. Yes. We made an adjustment for reductions related to cogeneration (which also includes a small amount of reductions due to fuel cells, energy storage and microturbines). In other words, the forecast was adjusted to reflect the projected loss in delivery for customers who plan to supply a portion, or all, of their existing load using on-site generation.

Q. What were the forecasted reductions to the commercial & industrial electric sales forecast resulting from cogeneration?

A. As set forth in column 6 on Exhibit __ (SRFP-4), the cogeneration reductions to the commercial & industrial electric sales forecast are: 369.2 GWh for 2015; 375.7 GWh for 2016; 382.3 GWh for 2017; and 388.9 GWh for 2018.

Q. Mr. Irrgang, please summarize the total commercial & industrial electric sales forecast.

A. Once again referring to Exhibit __ (SRFP-2), in columns 3 through 10, the projected customers in rows 4 through 8 are multiplied by the model predicted use per customer values in rows 11 through 15, resulting in the calculated sales shown in rows 18 through 22. Next the calculated sales are calibrated to the projected year-end sales for the current year as shown in rows 25 through 29. Finally the sales reductions shown in rows 32 through 36 are subtracted from the calibrated sales, resulting in the sales forecast shown in rows 39 through 43. In summary, as shown in rows 10 through 13 of columns 3 and 7 on Exhibit __ (SRFP-5), the Panel is forecasting commercial & industrial electric sales growth rates (after accounting for reductions due to the DSM and cogeneration out-of-model adjustments) of: 1.62% (158.0 GWh) for 2015; 2.10% (208.9 GWh) for 2016; 0.72% (72.7 GWh) for 2017; and 0.04% (3.8 GWh) for 2018. After adjusting for leap years as shown in rows 16 through 19 of columns 3 and 7 of the exhibit, the growth rates are: 1.62% (158.0 GWh) for 2015; 1.82% (181.2 GWh) for 2016; 0.99% (100.5 GWh) for 2017; and 0.04% (3.8 GWh) for 2018.

V. OTHER ELECTRIC SALES FORECAST

Q. Mr. Irrgang, were there other categories of electric sales the Panel forecasted?

A. Yes. In addition to residential and commercial & industrial sales, we also forecasted sales related to other public authorities, street lighting, and electric vehicles. These forecasts are summarized on Exhibit __ (SRFP-3).

Q. Were these forecasts developed using econometric modeling?

A. No.

Q. Please describe the forecast related to sales to other public authorities.

A. The forecast for this category relates to two customers: the Brookhaven National Laboratory ("BNL") and the Long Island Railroad ("LIRR"). For BNL, we are projecting that its electric load will essentially be stagnant through 2018. The forecasted load for LIRR came directly from LIRR.

Q. How were the street lighting electric sales forecasted?

A. Since customer growth in this area has been stagnant or on the decline, the street lighting sales forecast was developed by looking at trends for existing connected devices. The Company has seen a decrease in sales per existing connected device as more efficient lamps are replacing older lamps. As a result, the Company is forecasting a slight decrease in its street lighting sales.

Q. How were electric sales related to electric vehicles forecasted?

A. This forecast was based on projected population growth and electric vehicle registration trends.

Q. Were any out-of-model adjustments made to the "other" category?

A. No.

Q. Mr. Irrgang, please summarize the total "other" electric sales forecast.

A. As shown in rows 10 through 13 of columns 4 and 8 on Exhibit __ (SRFP-5), the Panel is forecasting "other" electric sales growth rates of: -1.12% (-6.7 GWh) for 2015; 0.43% (2.5 GWh) for 2016; 0.57% (3.3 GWh) for 2017; and 1.20% (7.1 GWh) for 2018. After adjusting for leap years as shown in rows 16 through 19 of columns 4 and 8 on the exhibit, the growth rates are: -1.12% (-6.7 GWh) for 2015; 0.16% (0.9 GWh) for 2016; 0.84% (4.9 GWh) for 2017; and 1.20% (7.1 GWh) for 2018.

Q. Mr. Irrgang, what is the Company's overall electric sales forecast?

A. Exhibit __ (SRFP-5) provides the Company's overall electric sales forecast. Specifically, as shown in rows 10 through 13 of columns 5 and 9 on the exhibit, the Company is forecasting electric sales growth rates of: 0.93% (184.1 GWh) for 2015; 0.95% (190.4 GWh) for 2016; -0.06% (-12.8 GWh) for 2017; and -0.12% -25.1 GWh) for 2018. After adjusting for leap years as shown in rows 16 through 19 of columns 5 and 6 on the exhibit, the growth rates are: 0.93% (184.1 GWh) for 2015; 0.67% (135.0 GWh) for 2016; 0.21% (42.6 GWh) for 2017; and -0.12% (-25.1 GWh) for 2018.

Q. Mr. Irrgang, how was the monthly sales forecast developed?

A. Average monthly sales distributions were calculated for the residential sector, for the commercial & industrial sector and for street lighting using the most recently available three years of weather normalized data. Then the annual sales forecasts for the residential, commercial & industrial and street lighting sectors described above were allocated to each month using those average distributions. The monthly distribution for the railroad was derived from recent load research analysis. Forecasted sales to Brookhaven National Labs were allocated using a fixed hourly amount.

Q. Mr. Irrgang, how did you validate the models used to develop the electric sales forecast?

A. In addition to the statistical results for the models shown on Exhibit _ (SRFP-1) and discussed previously, the Company has determined that its mean absolute percent error ("MAPE") of 1.6%, representing the average magnitude of the difference between forecasted next-year electricity use on Long Island and actual electricity use for the eleven year period from 2000 through 2011, compares favorably to the EIA's MAPE of 1.8% in forecasted versus actual electricity use for the nation over the same period. Furthermore, the Company has found that its MAPE of 1.3% for forecasted electricity use on Long Island versus weather-normalized electricity use over the nine year period from 2005 through 2013 compares favorably with the NYISO's MAPE of 1.9% for forecasted versus weather normalized electricity use in New York State over the same period. Additionally, we conduct ex-post analysis: the residential model prediction was 0.9% below the 2013 actual and the combined prediction for the eight commercial & industrial models was 0.5% below the 2013 actual.

VI. ELECTRIC CUSTOMER FORECAST

Q. Mr. Irrgang, how did the Panel develop PSEG LI's electric customer forecasts?

A. We developed the electric residential customer forecast based on trends in population growth obtained from Moody's Analytics. In our experience, the Company's residential customer growth closely mimics population growth in the service territory. Our commercial & industrial customer forecasts were based on trends in both population growth and employment growth. Again, our data source for this forecast is Moody's Analytics.

Q. What is PSEG LI's projected residential customer growth?

A. As shown in rows 11 through 14 of columns 2 and 4 on Exhibit __ (SRFP-7), in 2015, the Company is forecasting its residential customer base to increase by 3,000 customers, followed by customer increases of 2,500 in years 2016, 2017, and 2018. This equates to growth rates of approximately 0.30% in 2015 and approximately 0.25% per year for years 2016-2018.

Q. What is PSEG LI's projected commercial & industrial customer growth?

A. The Company's commercial & industrial customer forecast is also set forth in Exhibit __ (SRFP-7). As shown in rows 11 through 14 of columns 3 and 5 on the exhibit, the Company is forecasting its commercial & industrial customer base to increase by 400 customers in 2015, followed by customer increases of 350, 200 and 100 in years 2016, 2017, and 2018, respectively. This equates to growth rates of approximately 0.37% in 2015, 0.32% in 2016, 0.18% in 2017 and 0.09% in 2018.

VII. RISKS TO THE ELECTRIC SALES FORECAST

Q. Mr. Irrgang, please identify the risks that could change the sales forecast presented herein.

A. First, weather is the most obvious risk. About half of the time we attribute a change to annual sales (higher or lower) of at least 0.5% due to the occurrence of either hotter- or colder-than-normal variations in weather during summer periods, with winter periods contributing somewhat less variability. A second risk to the sales forecast is due to the economic outlook, which was provided by Moody's Analytics in August 2014 and hence will be 16 months old at the beginning of the three year period covered by this forecast, and which could differ significantly from the eventual economic conditions. Another risk is that further reductions to sales could occur under the Utility 2.0 program described elsewhere in this testimony. The Utility 2.0

program is discussed in detail in the direct pre-filed testimony of the Utility 2.0 and Energy Efficiency Panel.

VIII. ELECTRIC REVENUE FORECAST

Q. Mr. Karol, please describe how you calculated the forecasted electric delivery revenues.

A. Forecast electric delivery revenue is calculated in the Revenue Model. The Revenue Model consists of a series of linked Excel files that are used to forecast the revenue.

Q. What are the factors that have the biggest impact on the Revenue Model you support in this case?

A. Sales and growth projections as supported by Mr. Irrgang are the biggest drivers of the Revenue Model. Other influencing factors include projected changes in power supply and other costs.

Q. What are the inputs to the Revenue Model?

A. The first series of files reads in as input to the sales and customer forecast by Sector. Long Island Choice ("LIC") forecast is read in as input from another file and the LIC Sales and Customers are subtracted from the appropriate sector forecast. The Recharge New York sales forecast is also read in and subtracted from the commercial sector forecast. The Street Lighting, BNL and LIRR forecasts are also read in. Exhibit __ (SRFP-8) shows the incoming sales forecast.

Q. How do you process these inputs?

A. Sales are then broken into Rate Code ("RC") sales and customer forecasts based on historical ratios. The LIC forecast is received at a rate class level. This file then feeds a series of files that parse certain of the rate class data further, based on voltage, time of use as necessary.

These inputs then flow into the main module of the Revenue Model, where these sales are priced out at proposed tariff rates and meters are priced out at currently effective tariff rates. Demand for certain commercial rate codes is estimated based on historical ratios of demand to sales multiplied by the forecasted sales. This then gets priced out at currently effective tariff rates. The forecasted sales are multiplied by the forecasted monthly Power Supply Charge and the Efficiency & Renewable Charge. The Shoreham Property Tax Settlement Charge and New York State Assessment Surcharge are applied as percentages. The resulting amounts are then multiplied by the applicable state and local gross revenue tax ("GRT"). All of these components sum to the total revenue by RC by month. These individual rate codes are summed up on a sector basis. In addition, revenue that is not derived from sales is forecast in another Excel file based on historical actuals.

This main module of the Revenue Model then links to a Budget summary file which is typically used for Budget preparation. Exhibit __ (SRFP-9) is output from this file, depicting revenue from sales by rate class by components, including delivery revenue.

Q. How are the forecasted electric sales and customers allocated among the RCs?

A. Generally, the allocation is based on the historical percentage of sales allocation among the RCs. For example, if an RC historically accounts for 33% of the

Company's sales, the forecast assumes that that RC will continue to represent 33% of the Company's sales.

Q. Are all of the commercial RCs included in the revenue forecast?

A. No, the commercial electric revenue forecast is made up of only the major RCs. If an RC is not included in the forecast, the sales from that excluded RC are allocated to RC 285, the Company's largest commercial RC.

Q. Why is it necessary to breakdown the forecast into sub-RCs?

A. Breaking down the forecast into sub-RCs allows us to account for differences in the rates our customers pay within an RC, for example, due to time-of-use rates, primary versus secondary voltage.

Q. What is the Efficiency & Renewables Charge?

A. This charge includes Efficiency and Renewable Expenditures approved for recovery as outlined in the Tariff.

Q. Please explain the New York State Assessment Surcharge.

A. This surcharge recovers from customers payments mandated by Public Service Law § 18-a(6). The New York State Assessment is payable to the State of New York and has a stated intention to encourage conservation of energy and other resources on Long Island. We project annual reductions in the New York State Assessment Charge before the initiation of an annual $8 million DPS Assessment commencing January 1, 2016. This DPS Assessment is the only component of the New York State Assessment included in revenue projections after December 31, 2017.

Q. What is the Shoreham Property Tax Settlement Factor?

A. The factor is for the repayment of the Authority bonds with respect to the funding of the Shoreham Property Tax Settlement. It is applied as a surcharge to each customer's billed charges as dictated by the tariff.

Q. Please describe the Revenue Tax Charge

A. The bill for electric service is increased by surcharges to recover taxes imposed by cities, incorporated villages and New York State. Sales tax, if applicable, is shown separately on each bill and is not included in the revenue forecast.

Q. Please summarize PSEG LI's forecasted revenue from sales.

A. PSEG LI's total electric revenue (in $000s) from sales forecast for 2016 is approximately $3,697,474 ($3,528,574 for bundled customers and $168,900 for LIC customers), broken down by rate category as follows:

	($000)	
Rate Category	**Bundled Customers**	**LIC Customers**
Total Residential	$1,937,176	$288
Total Commercial	$1,514,119	$168,612
Total Street Lighting	$24,811	n/a
Total LIRR	$49,232	n/a
Total Brookhaven	$3,236	n/a

As shown in Exhibit __ (SRFP-9), PSEG LI is forecasting its total electric revenues from sales (in $000s) to increase to $3,711,708 in 2017 (0.4% increase) and then increase to $3,716,645 by 2018 (0.1% increase).

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-00262

REBUTTAL TESTIMONY
OF
BRYAN IRRGANG
ON
SALES AND REVENUE FORECASTING

Date: June 4, 2015

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I. <u>WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY</u>

Q. Please state your name and title.

A. My name is Bryan Irrgang. I am the Manager of Electric Load Forecasting for PSEG LI.

Q. Have you previously submitted pre-filed testimony in this proceeding?

A. Yes, as a member of the Sales and Revenue Forecast Panel.

Q. What is the purpose of your testimony here?

A. I will discuss my response to the prepared testimony of DPS Staff regarding the electric sales forecast for the rate plan period.

Q. Do you support any exhibits as part of your rebuttal testimony?

A. Yes. I support the following exhibits which were prepared by me or under my supervision:

Exhibit___(SRFP-REB-1) – Year-To-Date April & Annual Sales
Exhibit___(SRFP-REB-2) – System Sales Forecast
Exhibit___(SRFP-REB-3) – Sales Per Customer
Exhibit___(SRFP-REB-4) – Sales Forecast Check

Q. Do you have any preliminary comments?

A. I would like to begin by expressing my appreciation for Staff's efforts in reviewing the electric sales forecast provided with my direct pre-filed testimony and supporting exhibits. It appears we agree in a number of key areas. For example, Staff did not suggest that my method of developing sales forecasting models with an annual frequency was disadvantageous. Staff also did not suggest that my method of using electricity use per customer as the dependent variable in all of my sales forecasting models was less desirable than using total sales. I also note that Staff's approach was similar to mine in its use of both an annual model frequency and electricity use per customer as the dependent variable, which appears to suggest Staff's agreement with the arguments I made supporting that approach.

II. STAFF'S RECOMMENDED SALES FORECAST

Q. Have you reviewed the sales forecast submitted by Staff, covering the years 2015 – 2018, as presented on page 1 of Exhibit_(AL-2) ?

A. Yes. After careful analysis my conclusion is that the sales forecast recommended by Staff is unsupportable and should not be accepted in place of my sales forecast.

Q. Please explain how you reached this conclusion.

A. Examination of Staff's recommended sales forecast revealed an immediate and obvious concern that its projection for 2015 appeared to be significantly higher than could be reasonably supported. That high forecast for 2015 is carried forward through the subsequent years, rendering its entire forecast for the years 2015 through 2018 unacceptable.

Q. What indication did you find that Staff's recommended system sales forecast for 2015 appeared high?

A. Using the 19,852,246 MWh of weather normalized sales reported for the system for 2014 (and as provided in response to DPS-PRELIMINARY-0069) as a reference point, in order to reach Staff's recommended system sales forecast of 20,361,737 MWh in 2015 would require 509,491 MWh (2.6%) of annual growth, an amount that has not been approached in ten years.

Q. Did you investigate further?

A. Yes, I found that Staff's recommended sales forecast for 2015, in comparison to weather normalized experienced sales for 2014, included slight decreases of 8,384 MWh (0.1%) in residential sales and 4,985 MWh (0.8%) in other sales (for street lighting, railroad, Brookhaven National Labs and electric vehicles) but an exceptionally large increase of 524,534 MWh (5.3%) in commercial and industrial sales. From the weather normalized value of 9,730,020 MWh of commercial and industrial sales reported for 2014 (and as provided in response to DPS-SRFP-0402), Staff's forecast of 10,254,554 MWh for 2015 would represent an unprecedented amount of annual growth, one that has never been approached. Therefore, in my review of Staff's forecast, I focused my attention on commercial and industrial sales.

Q. How did you confirm your concerns about Staff's commercial and industrial sales forecast for 2015?

A. By consideration of weather normalized sales experienced during the January through April period and the subsequent full year sales. The 2,970,213 MWh of weather normalized commercial and industrial sales experienced during January through April 2015 is 24,816 MWh (0.8%) below the 2,995,029 MWh of sales experienced last year, suggesting that sales are not maintaining the pace of last year. Furthermore, weather normalized commercial and industrial sales for January through April 2015 are below the amount for the same period in each and every one of the last eleven years; however, not once during those years did the subsequent annual sales reach the amount recommended by Staff for 2015, as shown in Exhibit___(SRFP-REB-1).

Q. Did you consider anything else to confirm your concerns?

A. Yes, I also considered that the weather normalized commercial and industrial sales for January through April 2015 are tracking 95,973 MWh below LIPA's approved budget forecast. This year-to-date sales variance indicates projected year-end sales of 9,836,799 MWh, which is 417,775 MWh (4.0%) below DPS Staff's forecast.

Q. How could the concerns you have raised about DPS Staff's sales forecast been avoided?

A. During an initial check to establish reasonableness, the growth represented by DPS Staff's sales forecast for 2015 over the weather normalized sales reported for 2014 should have been thoroughly analyzed. Such an analysis would have revealed that DPS Staff's forecasted growth in commercial and industrial sales for 2015 appeared questionably high by historical standards.

Q. Please explain how the concerns about DPS Staff's sales forecast might have been addressed.

Year-to-date sales should have been examined in comparison with historical sales during the past ten years. This would have revealed that weather normalized commercial and industrial sales were not keeping pace with the sales for the same period during those prior years. At this point, the review would have revealed considerable evidence that DPS Staff's recommended sales forecast for 2015 is unlikely to be reached and so a more supportable forecast incorporating the year-to-date sales results would have been developed.

Q. How would that be accomplished?

A. There are a couple of ways to accomplish this step. One method would be to combine the weather normalized sales for January through April 2015 with the sales for May through December 2014. Another method would be to adjust the sales forecast in LIPA's Approved 2015 Budget with the year-to-date April sales variance. The latter method is preferred because the approved budget represents the economic outlook for 2015 while the former method relies heavily upon the economic conditions that existed in 2014. In addition, LIPA's Approved 2015 budget forecast was independently examined by the NYISO and found to compare favorably to their own internally developed forecast and thus was accepted by the NYISO for incorporation in its 2015 Load and Capacity Data "Gold Book" report, which is the statewide resource and reliability planning reference.

Q. Was LIPA's approved 2015 budget sales forecast available to the DPS Staff?

A. The 2015 sales forecast is included in LIPA's approved 2015 budget document which is available from the LIPA web site. Also, the associated 2015 budget sales forecast was submitted by PSEG LI in this proceeding with the direct pre-filed testimony of the Sales and Revenue Forecasting Panel, Exhibit__(SRFP-REB-5). DPS Staff did not request any of the monthly 2015 budget variance reports.

Q. What are the projected year-end sales that resulted from the 2015 budget variance analysis?

A. To begin, the projected-year-end ("PYE") values should be developed for all of the major components of the sales forecast. LIPA's Approved 2015 Budget sales were adjusted as follows: residential sales were adjusted up by the year-to-date variance of

43,352 MWh (0.5%) to 9,602,654 MWh; commercial and industrial sales were adjusted down by the YTD variance of -95,973 (-1.0%) MWh, to 9,836,799 MWh; other sales (street lights, railroad, Brookhaven National Labs, electric vehicles) were adjusted up by the YTD variance of 9,272 MWh (1.6%) to 594,718 MWh. Utilizing the Approved 2015 Budget and the sales variance for January through April, the projection for system sales is 20,034,170 MWh, which is 327,567 MWh (1.6%) lower than DPS Staff's recommended sales forecast for 2015.

Q. How could the 2015 projected-year-end sales be used to avoid the concerns with DPS Staff's recommended sales forecast?

A. The procedure is referred to by the Company as calibration. First, the reductions proposed by DPS Staff would be added back to DPS Staff's recommended sales forecast and also to the new PYE forecast for 2015. Next, the PYE 2015 sales would replace DPS Staff's recommended sales forecast for 2015. Then the growth rate (before reductions for DSM and cogeneration) from DPS Staff's forecast for 2016 would be applied to this new starting point. Next in turn annual growth rates from DPS Staff's forecast for 2017 and 2018 would be applied in the same manner. Finally, the reductions would be subtracted from the sales to produce the calibrated sales forecast.

Q. Is calibration of the sales forecast necessary?

A. I believe so. Calibration of the sales forecast accomplishes two important functions: first, calibration aligns the initial sales forecast with calendar month sales. Since the electricity use models are developed using the billing sales history, the initial sales forecast is more representative of billing month sales rather than calendar month sales. However, it is calendar month booked sales and revenues that are used for budgets and financial reporting. History has shown that the differences between billing month and calendar month sales can be considerable, even on an annual basis. Second, since the electricity use models are developed from annual data, calibration is a technique to incorporate the latest, though not full-year sales results into the process. The Company applied calibration to our own initial sales forecast before filing, as described in the direct pre-filed testimony of the Sales and Revenue Forecasting Panel on page 15 for residential sales and page 21 for commercial and industrial sales. The calibration process was further described in the Company's response to DPS-SRFP-0239.

Q. Did DPS Staff provide an explanation as to why they did not calibrate their initial sales forecast?

A. The question was addressed on page 31 in the prepared testimony of DPS witness Liu:

> Q. Is a recalibration procedure required for your model forecasts?
>
> A. No. Because my forecast models are developed using historical data through 2014 and the model forecast has already reflected the full year sales of 2014.
>
> Q. Without a calibration adjustment, is your annual sales forecast representative of annual calendar month sales for the forecasting period?
>
> A. Yes. Although my models are developed using historical annual data of billing month sales, the forecast should be representative of the annual calendar month sales.

The witness goes on to explain that the differentials "for February through December will be eliminated when summed to the annual total," "thereby leaving only a small year-to-year differential that may exist in part of the calendar month of December," which "should be minimized with a normal weather assumption."

First, by neglecting to consider calibration, DPS Staff chose to ignore the sales experience for January through April of this year, which temporally represents one third of the year and therefore could have given a fairly reliable indication of whether or not its forecast was on track – as explained above; the evidence suggests that their forecast is not on track. Second, annual billing month and calendar month sales can differ significantly, beyond weather effects and it is unreasonable, in my view, to ignore the risk.

Q. If DPS Staff had calibrated their initial sales forecast to incorporate the results for January through April of this year as you described above, what would DPS Staff's forecast have shown?

A. DPS Staff's calibrated sales forecast would be significantly lower than PSEG LI's sales forecast filed in this proceeding, in each of the years from 2016 through 2018, which follow from the decrease in the 2015 sales forecast. The results are shown in Exhibit___(SRFP-REB-2) which compares DPS Staff's recommended sales forecast, DPS Staff's forecast after calibration by PSEG LI and PSEG LI's filed sales forecast.

Q. Exhibit_(AL-4), pages 3 and 5 showing DPS Staff's Residential and Commercial Sales Forecast Models, are dated April 2, 2015 - presumably by the software used to generate those models. At that time, obviously, sales for the complete month of April were unknown. Would an analysis using January through March sales suggest an outcome different from the conclusion reached when the sales results for April were also considered?

A. No, the conclusion would have been the same. The weather normalized year-to-date commercial and industrial sales through March also tracked well-below both the prior year and below the approved 2015 budget forecast. Since temporally the three-month period represents one quarter of the year, this is still a significant indication of the need for calibration. DPS Staff's recommended sales forecast, if calibrated to the 2015 projected year-end sales developed using the weather normalized sales results for January through March only, would not be significantly different from the one described earlier which was calibrated to the PYE sales developed to include the April sales results.

Q. Would an analysis using the ten-year average definition of cooling- and heating-degree-days recommended by Staff instead of the thirty-year average used by PSEG LI have led to a different conclusion?

A. No, the conclusion would have been the same because first, the difference in annual sales when weather-normalized by replacing degree day averages for a thirty-year period with averages for a ten-year period is small, less than 0.2% and second, all sales results previously weather-normalized would move in the same (lower) direction so the difference would remain more or less unchanged.

III. <u>DPS STAFF'S MODELS</u>

Q. Please describe DPS Staff's sales forecast modeling.

A. DPS Staff developed two sales forecasting models, one for residential sales and the other for commercial and industrial sales. Using a single model for the residential sales forecast is appropriate because the residential customers are fairly homogeneous with 85 to 90 percent of electricity use consumed by customers in the General Use rate class. There is, however, significant diversity among the commercial and industrial customers. One indication of the diversity is by rate class: About 47 percent of customers are in the Small General Use rate class but consume about 5 percent of the electricity; about 48 percent of customers are in the Large General Use class and consume about 35 percent of the electricity; and about 5 percent of customers are in the Large, Multiple Rate Period class and consume about 60 percent of the electricity. Another measure of the diversity in electricity use within the commercial and industrial sector is by NAICS sectors. For example, thirty years ago about 18 percent of electricity was consumed in the manufacturing sector, while now it is down to about 8 percent. As another example, electricity use per customer has increased by about 7 percent since the late 1980s for the entire commercial and industrial sector, but it has increased by 37 percent in the trade, transportation and utilities sector while declining by about 20 percent in the manufacturing sector. The point here is that a lot of information is lost when the entire commercial and industrial sector is represented by a single model which is why my preference is to model by NAICS sectors. For these reasons, in my view, using a single model to forecast commercial and industrial electricity sales is a simplified and unsupportable approach.

Q. Briefly describe the advantages of forecasting commercial and industrial electricity use by using eight NAICS sector models over the single model approach used by DPS Staff.

A. When the U.S. Department of Labor releases the Jobs Report each month (which usually occurs on the first Friday of the month) media attention properly focuses on which sectors are experiencing growth. For example, it examines whether there is more growth in the relatively low wage retail sector or in the better quality, more highly paid financial services sector, because some jobs are better for the economy than others. The major economic series of employment and gross Long Island product are provided by our consultant by NAICS categories and therefore they align well with my models. In summary, since customers have different energy use intensities depending on which sector they are in, utilizing NAICS models that accept NAICS input assumptions is a more comprehensive way to develop the commercial and industrial electricity sales forecast in comparison to DPS Staff's single model approach.

Q. Please respond to DPS witness Liu's testimony that PSEG LI's forecast should not be adopted because "generally, most of the forecast models are specified incorrectly or failed important econometric tests"?

A. In the context of forecasting energy use for Long Island, the most important test is forecast accuracy. I have been using the same general configuration of one residential and eight NAICS sector regression models for 15 years and can report a mean absolute percent error (MAPE) of 1.1%. In my direct pre-filed testimony for the Sales and Revenue Forecasting panel on pages 23-24 I described how my forecast accuracy compares favorably to that of the EIA and the NYISO during overlapping periods.

Q. Please address the concern raised about positive serial correlation in your models?

A. The Durbin Watson test shows that the possibility of the presence of positive serial correlation cannot be rejected for three of my eight NAICS models (at the 5% significance level) indicating the undesirable possibility that adjacent residuals may be tending to cluster by sign (auto-correlated). One method to address autocorrelation is to utilize an adjustment model which predicts the current value of the dependent variable using adjustments to the previous (or lagged) values of both the dependent and explanatory variables. Such a model estimates a coefficient of adjustment to establish how much of the lagged variables are used to make predictions. If the coefficient of adjustment had a value of zero then there would be no impact from either the lagged dependent or explanatory variables and only the current values of the explanatory variables would be used to predict the dependent variable. A coefficient of adjustment with a value of unity represents the other extreme, and the predicted value of the dependent variable would include the full value of the lagged dependent variable. Staff proposes a residential sales forecasting model with a coefficient of adjustment close to unity at 0.95530 (shown as the AR(1) autoregressive term on page 3 of Exhibit_(AL-4)), which for the intended application leaves relatively little of the prediction to be explained by the explanatory variables. My opinion is that this is not a satisfactory approach to forecasting annual electricity use on Long Island, and for this particular application auto-regression should be reserved for confirmation of the results obtained from more fully specified models, as I'll explain further on.

Q. How do you address the concern raised about multicollinearity in your models?

A. It is well known that much economic data exhibits some degree of linear dependence, known as multicollinearity. One solution would be to remove from the regression model those explanatory variables which exhibit a near-linear dependence. If the relationship between explanatory variables is not perfectly linear, than some information may be lost when variables are dropped. Alternatively, one can usually obtain good forecasts despite the presence of multicollinearity, although it may be difficult to disentangle the influences of the explanatory variables. In my view, in this particular application of forecasting electricity use for Long Island, including more explanatory variables is justified.

Q. How do you ensure that your modeling preferences are not leading to misleading sales predictions?

A. Although it is my preference not to employ auto-regression to address serial correlation and not to exclude explanatory variables which are significant but may exhibit some linear dependencies, I typically perform a robustness check to confirm the acceptability of the sales forecast under development. The robustness check consists of identifying those models that exhibit the possibility of positive serial correlation in the residuals and/or multicollinearity in the explanatory variables from among the nine regression models that are under consideration for developing the sales forecast. The identified models are then re-specified utilizing a single economic variable to address concerns about multicollinearity and/or by introducing a coefficient of adjustment auto-regressive term to address concerns about positive serial correlation. Results for the robustness check results are shown in Exhibit___(SRFP-REB-3). Note that these re-specified models exhibit low possibilities of the presence of either serial correlation or multicollinearity but generally have less explanatory capability than the preferred models already presented in Exhibit__(SRFP-1). Results from these re-specified models provide a check of the robustness of my recommended sales forecast. For this illustration, I re-specified six out of the nine sales forecasting models while three of the preferred models were retained. Among the six re-specified models, five contain an auto-regressive term and economic variables were dropped from three models. The resulting predicted annual growth rates for sales represents what I consider to be acceptable differences, relative to the MAPE described above, when compared to the filed forecast. See Exhibit___(SRFP-REB-4).

Q. Please summarize your position on the models.

A. Developing sales forecasting models involves a series of preferences. DPS Staff has chosen a simplified approach to modeling electricity use on Long Island. DPS Staff has developed two models, each utilizing a single econometric variable, income (per capita) in the residential model and real gross metro product in the commercial and industrial model, with all other economic impacts on electric sales occurring by proxy. So for example, in 2009 growth in real gross metro product declined by 0.6%, about the same as the decline for the prior year of 0.7%; however, employment declined by 2.9%, much more steeply than the decline of 0.1% in the prior year, and commercial and industrial sales declined by 4.8%, again much more steeply than the decline of 1.1% for the prior year. In this case, the change in sales and employment were similar to each other and dissimilar from real gross metro product. The situation is further exacerbated by DPS Staff’s use of a single model for the entire commercial and industrial sector, meaning much information about the dissimilar NAICS sectors does not contribute to the commercial and industrial sales forecast. In comparison to DPS Staff’s two simple models, my nine models present a more complete representation of electricity use on Long Island, incorporating more economic information of significance, including income, home prices and interest rates, employment, and real gross metro product by NAICS sector. Finally, the sales forecasts resulting from my models are checked for robustness against simpler models. For these reasons my sales forecasting models should be accepted over DPS Staff's models.

Q. Have you reviewed DPS Staff's recommended customer forecast?

A. Based on the results through April, while DPS Staff's residential customer forecast appears reasonable, its commercial and industrial customer forecast is not and it is the Company's commercial and industrial customer forecast that is more likely to occur.

Q. Do you have an opinion on DPS Staff's residential and commercial and industrial customer forecasting models?

A. The difference is that the DPS Staff's customer forecast models use auto-regressive adjustments to the customer level from the previous year with some contribution made by the expected growth in the dependent variable, households for residential customers or employment for commercial and industrial customers. The Company uses a committee to consider customer growth from prior years, expected growth in households, population and employment and also information from the Construction and Marketing departments.

Q. Did you review DPS Staff's comments regarding the Company's EER forecast?

A. Yes. DPS Staff, in their remarks concerning appliance standards and building codes, correctly states that the Company's projections for 2014 – 2015 were developed from a straw proposal for setting goals to reduce energy usage by 15 percent statewide by

2015. However, they neglected to state that the Company is using only one third of the proposed reductions, as demonstrated in our response to DPS-SRFP-0329. Although it is reasonable to assume that the curtailment of electricity use due to building codes and appliance standards as reflected in the sales history is captured by the sales forecasting models and propagated forward in predictions, it is not prudent to assume that all future effects are captured, since these reductions are taking place gradually over time, as noted by DPS Witness Liu on page 35 of his testimony in this proceeding. Therefore the approach of the Company to make continuing, although deeply discounted reductions for building codes and appliance standards in electricity use forecasts is sensible. Furthermore, in contradiction to DPS Witness Liu's statement on page 36 of his testimony in this proceeding, the Company's approach of reducing electricity use forecasts for building standards and appliance codes is not unique in the region. The NYISO, for example, explains in Section I (on pages 9 – 10) of its 2015 Load and Capacity Data "Gold Book" report:

> The NYISO employs a two-stage process in developing load forecasts for each of the 11 zones within the NYCA (New York Control Area). In the first stage, zonal load forecasts are based upon regression models that are reflective of annual changes in economic conditions and weather. In the second stage, the NYISO prepares forecasts of energy reductions resulting from statewide energy efficiency programs, new building codes and appliance efficiency standards, and the impact of retail solar PV. These forecasts are based upon new and updated information about the performance of such programs provided by the New York State Department of Public Service (DPS), the New York State Energy Research and Development Authority (NYSERDA), state power authorities, electric utilities, and through NYISO's

previous participation in the DPS Evaluation Advisory Group.

Q. Please discuss DPS Staff's proposed ten percent adjustment to the Company's DSM savings projections.

A. The DPS devised a ten percent reduction to DSM which is described as being specific for their sales forecasting models. I agree with the implication that the DSM savings as adjusted by DPS Staff are not appropriate for my sales forecast.

Q. Please summarize your recommendation for DSM.

A. The assumptions underlying the Company's development of reductions for building codes and appliance standards are reasonable and furthermore reducing forecasted electricity use by those expected reductions is consistent with the approach used by the NYISO for all of the Zones in New York State. Also, the DSM adjustments developed by DPS Staff are not applicable to the Company's sales forecast. For these reasons the reductions for building codes and appliance standards and the remaining components of EER as proposed by the company should be retained.

Q. Did you review DPS Staff's remarks concerning normal weather conditions for electric sales forecasting?

A. Yes. On the issue of normal weather I defer to the National Weather Service which continues to define normal weather as the average for a 30-year period. On the issue of normal weather for forecasting electricity use my method is consistent with the Energy Information Administration which used 30-year average weather for their 2014 Annual Energy Outlook report. I also found it inconsistent that DPS Witness Liu, on page 28 of his testimony in this proceeding, recommended using ten-year average weather for sales forecasting but using 30-year average weather for peak load forecasting. For these reasons the Company’s use of 30-year average weather should be accepted.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

JUDGE PHILLIPS: The next affidavit should be from Staff witness Liu.

MR. MAZZA: Thank you, Your Honor. I would like to enter by affidavit the updated testimony and exhibits of Dr. Anping Liu Submitted on June 11, 2015 consisting of Prepared Updated Testimony which consists of 45 pages plus a title page and prepared exhibits which include AL-1 consisting of 44 pages, updated exhibit AL-2 consisting of one page, Exhibit AL-3 consisting of one page, updated Exhibit AL-4 consisting of five pages and Exhibit AL-5 consisting of five pages plus a cover page and indexes. They are on their way, Your Honors.

MR. FORST: (Handing).

JUDGE PHILLIPS: We have the affidavits from Witness Liu from the Department Staff referring to the Updated Testimony that was provided, and that will be copied into the record as though orally given on the basis of this affidavit which has been marked for identification as Exhibit 111 so 111.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

In the Matter of a

THREE-YEAR RATE PROPOSAL FOR ELECTRIC RATES AND CHARGES SUBMITTED BY THE LONG ISLAND POWER AUTHORITY AND SERVICE PROVIDER, PSEG LONG ISLAND LLC.

Matter Number 15-00262

June 2015

Prepared Updated Testimony of:

Anping Liu
Principal Econometrician
Office of Market and Regulatory Economics

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

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

A. My name is Anping Liu. I am employed by the New York State Department of Public Service, which I refer to as the “Department.” My business address is Three Empire State Plaza, Albany, New York.

Q. What is your position at the Department?

A. I am employed as a Principal Econometrician in the Office of Market and Regulatory Economics.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Mathematics from Shaanxi Normal University in 1982, a Master of Science from Huazhong University of Science and Technology in 1985, and a Ph.D. in Economics with specialties in Industrial Organization and Public Economics from Wayne State University in 1991. I joined the Department in 1992.

Q. Please briefly describe your current responsibilities with the Department.

A. My current responsibilities include reviewing and developing utility electric sales forecasts and monitoring the wholesale electric market in New York State.

Q. Have you previously testified in any ratemaking proceedings?

A. Yes. I have testified on electric sales forecasts, wholesale electricity supply costs, and the economic impact of the increasing price of electricity. I provided testimony in Cases 14-E-0493, 14-G-0494, and 10-E-0362, Orange and Rockland Utilities, Inc.; Cases 13-E-0030, 09-E-0428, 08-E-0539, and 07-E-0523, Consolidated Edison Company of New York, Inc.; Case 05-E-1222, New York State Electric & Gas Corporation; Cases 03-E-0765, 02-E-0198, and 95-E-0673, Rochester Gas and Electric Corporation; and Case 02-E-1055, Central Hudson Gas & Electric Corporation. All of these proceedings were before the New York State Public Service Commission.

Q. What is the purpose of your testimony in this proceeding?

A. I will discuss my recommendation regarding the electric sales forecast for Long Island Power Authority, referred to as LIPA, proposed by PSEG

Long Island LLC, which I will refer to as PSEG LI or the Company. Specifically, I reviewed and will address the testimony of PSEG LI's Sales and Revenue Forecasting Panel, which I will refer to as the SRF Panel.

Q. In your testimony, will you refer to, or otherwise rely upon, any information produced during the discovery phase of this proceeding?

A. Yes. I will refer to, and have relied upon, several responses to Staff Information Requests, referred to as IRs. The IRs that I have relied upon are included in Exhibit___(AL-1).

Q. Are you sponsoring any other exhibits in support of your testimony?

A. Yes. I am sponsoring four more exhibits, which were prepared by me or under my supervision. Exhibit___(AL-2) is a summary of my forecast with a comparison to PSEG LI's forecast. Exhibit___(AL-3) summarizes my forecast assumptions. Exhibit___(AL-4) provides the output and statistics of my forecast models. Exhibit___(AL-5) provides the results of statistical tests or analyses of some of PSEG LI's forecast models.

Q. Have you developed your own electric sales forecast?

A. Yes, I have. A summary of my forecast, with a comparison to that of PSEG LI, is provided in Exhibit___(AL-2).

Q. Please summarize your recommendation.

A. I forecast total electric sales to be 20,419 Gigawatt hours (GWhs) for 2016, and 20,306 and 20,226 GWhs, respectively, for 2017 and 2018.

Q. Please describe PSEG LI's electric sales forecast.

A. PSEG LI forecasts total electric sales to be 20,268, 20,255, and 20,230 GWhs, respectively, for 2016-2018.

Q. To what degree does your forecast differ from that of PSEG LI?

A. My forecast is 151 GWhs or 0.7 percent above PSEG LI's forecast for 2016. The difference decreases to 51 and 4 GWhs for 2017 and 2018, respectively.

Q. What methodology did you use to develop your forecast?

A. I used econometric time series models to develop my sales forecast. My econometric time series models consist of sales forecast models and customer forecast models.

Q. What is an econometric time series model?

A. An econometric time series model combines regression analysis with time series analysis, which consists of a structural component and a time series component. The structural component is similar to a regression model, which relates electric sales or number of customers to a set of explanatory variables. An energy forecast model typically includes weather and economic variables, such as cooling degree days, or CDDs, heating degree days, or HDDs, price of electricity, and an economic “driver.” Widely used economic drivers are various statistical factors derived from the service area such as, personal income, population, number of household, employment, and gross product. An economic driver is chosen by economic principles, depending on forecasting model and customer sector.

Q. What is the time series component?

A. Electric sales and number of customers are time series data, which may have variances that cannot be structurally explained by a regression analysis. The time series component is a process that accounts for these variances through a time series analysis of the regression residuals. This component is included in some of my forecasting models to recognize the presence of the relationship among residuals in different periods that often appear in time series data. The time series component of each model has its own structure that is statistically determined by the data pattern of the modeled time series.

Q. What are the advantages of using econometric time series models for electric sales forecast?

A. A regression model incorporating time series analysis is likely to provide much better forecasts than the regression model alone because variances in the electric sales that cannot be explained structurally by the regression equation have been accounted by the time series analysis. Through the time series component, information in the residuals of the econometric model is utilized and the forecast errors are reduced.

Q. How is an econometric time series model estimated?

A. An econometric time series model is estimated using historical data. The historical data I used are 31 years of data for electric sales, number of customers, average electricity prices, weather, and other economic variables in LIPA's service territory from 1984 through 2014.

Q. What is the source of your data?

A. Historical data was provided by PSEG LI in its responses to DPS-Preliminary-68, DPS-SRFP-255, DPS-SRFP-325, and DPS-SRFP-297, which are included in Exhibit___(AL-1).

Q. Please describe the PSEG LI's forecasting methodology.

A. PSEG LI used a hybrid methodology combining regression models, trend analysis, and a calibration procedure to develop its sales forecast. Its customer forecast is based on a trend analysis. It developed regression models for sales forecasts using 30 year historical data from 1984 through 2013. At the time when the forecast was developed, only nine months of data for 2014 sales was available. PSEG LI projected the full year 2014 sales using its on-going booked sales process based on the nine month of experienced sales. Its final forecast was obtained through a calibration process by applying the annual growth rates of the model forecasted sales to the projected booked sales for 2014.

Q. Please explain why PSEG LI’s forecast should not be adopted.

A. Generally, most of the forecast models either are specified incorrectly or failed important econometric tests.

Residential Sales Model

Q. Please discuss PSEG LI’s residential model.

A. As shown in the Company’s Exhibit___(SRFP-1), PSEG LI’s residential model assumes use per customer as a regression function of price of electricity, CDDs, and four economic variables. These four economic variables are personal income, employment, gross metropolitan product or GMP, and median home price in the LIPA service territory.

Q. What concerns do you have with PSEG LI’s residential model?

A. First, the residential model does not comply with economic principles. The relationship between energy demand and personal income is fundamental to the theory of consumer choices constrained by income or budget. It is commonly recognized by economic principles that a consumer’s energy use is directly related to income and inversely related to price of energy. Residential customers use electricity indirectly from electric appliances and electronic devices they own in their residences. Home ownership and appliance purchases are largely dependent on household income. As such, personal income by economic principle is a preferred economic driver in a residential energy demand model. Including other highly related economic variables in a residential model leads to over-specification and does not comply with economic principles.

Q. What is your second concern with PSEG LI’s residential model?

A. Some of the four economic variables of the residential model are likely highly correlated. High correlation among explanatory variables, known as multicollinearity, causes highly inflated variances of the estimated model parameters.

Q. Which economic variables of the residential models are correlated?

A. Both employment and GMP are likely to be positively correlated with personal income. On the one hand, when regional employment grows, total wages and compensations grows and so does total regional personal income. On the other hand, GMP moves hand in hand with personal income, because regional personal income is a major component of GMP by definition.

Q. Have you prepared an exhibit to demonstrate that PSEG LI’s residential model has this multicollinearity problem?

A. Yes. I have performed a coefficient diagnostics called Variance Inflation Factor, or VIF, for PSEG’s residential model. As the test result on page 1 of Exhibit__(AL-5) shows, the “Uncentered VIF” column shows the variances of the income, employment, and GMP variables are inflated by more than 1800 to 3600 times and the ”Centered VIF” column shows that the variance of for income and GMP variables are inflated by 24 to 48 times. This indicates that the variances of the coefficients for the three variables are significantly inflated as result of multicollinearity.

Q. What implications does the multicollinearity problem have for a regression model?

A. The reported regression results are unreliable because the assumption of zero collinearity among explanatory variables is violated. Intuitively, the regression analysis is distorted by the high correlation among the independent variables, leaving very little information available to estimate the individual impact of these variables. As a result, individual coefficients of these economic variables cannot be estimated correctly and accurately. A model with high multicollinearity is neither robust nor reliable because of significantly inflated sampling variance and great sensitivity to small data changes.

Q. What other concerns do you have with PSEG LI’s residential sales model?

A. The Company’s residential sales model does not have a HDD variable. This is in contradiction to LIPA’s experience of electric usage in winter and it is inconsistent with PSEG LI’s practice for weather normalization. As explained in its response to DPS-Preliminary-69, included in Exhibit___(AL-1), electric sales in LIPA’s service area do vary with HDDs. Exclusion of a HDD variable is incompatible with its methods used to project the 2014 full year sales, which form the base level of its residential sales forecast. Also, the lack of a HDD variable is not consistent with residential sale forecast models used by other electric utilities in New York.

Q. On lines 5 through 9 of page 9, PSEG LI stated that HDD was not a significant variable and there are not enough customers with electric heat to make HDD a significant variable. How do you respond to this statement?

A. First, the insignificance of HDD may be a result of model over-specification that causes multicollinearity problem. As I will discuss below, my residential model does not have a multicollinearity problem and HDD is a significant variable. Second, attributing the insignificance of HDD to not enough customers with electric heat cannot be justified. During the winter, use of electricity varies not only for customers with electric heat but also for customers with gas heat. The most common residential gas heat furnace is a forced-air central heating system with a blower run on electricity. More than 440,000 of LIPA’s residential customers are also natural gas customers. The significantly large number of combined electric and gas space heat customers should have made HDD a significant variable.

Q. Have you developed your residential sales model?

A. Yes, I have. My residential sales model is a per customer use model in transfer functional form. The model’s explanatory variables include real price of electricity, per capital real personal income, CDDs, and HDDs. My residential sales model also includes a leap year adjustment variable and an autoregressive term. My model does not have the shortcomings of PSEG LI’s model, because it uses personal income as the only economic driver.

Q. What is the leap year adjustment variable?

A. The leap year variable assumes value of 365/366 for leap year and 1 otherwise. The purpose of this variable is to normalize historical sales data by removing the variation in electric sales due to the extra day in a leap year.

Q. What is the autoregressive term?

A. First, order autocorrelation, or a phenomenon where a current error term is related to previous error term, was detected during the regression analysis. The autoregressive term is included to account for this serial relationship. With the inclusion of an autoregressive term, a generalized, instead of ordinary, least square regression method is used by an iterative process to estimate the model.

Q. What format is your residential regression equation component?

A. Both the dependent variable and the explanatory variables are transformed into logarithms to recognize the existence of the non-linear relationship between price and use per customer. Such a log-linear regression equation has been widely used for analyzing energy demand. A logarithmic transformation reduces regression errors since the residuals now represent difference in logarithms. Another advantage is that an estimated coefficient is the average ratio of percentage changes between sales and the explanatory variables. The coefficient for price of electricity is the well-known price elasticity of demand for electricity, which represents percentage change in electric use in response to one percent change in electricity price.

Q. Have you prepared an exhibit to show your estimated residential model?

A. Yes, I have. The output and statistics of my residential sales model, along with the model forecast, are provided on page 3 of Exhibit___(AL-4). All included explanatory variables are statistically significant. The model has an adjusted R-square of 0.98 and a Durbin-Watson statistic of 2.3.

Q. What is the Durbin-Watson statistic?

A. The Durbin-Watson statistic is provided by a regression analysis to test whether the first order autocorrelation is present in the model.

First order autocorrelation exists when regression residuals in adjacent periods are correlated.

Q. How is the Durbin-Watson statistic used to test the existence of first order autocorrelation?

A. The Durbin-Watson statistic ranges from zero to four. In general, first order autocorrelation can be ruled out if the Durbin-Watson statistic is close to two. First order autocorrelation cannot be ruled out if the Durbin-Watson statistic is too low or too high. How low or how high depends on a pair of two critical values, which are determined by the number of observations of the historical data and the freedom of the model.

Q. How are the critical values used to perform a Durbin-Watson test?

A. Positive autocorrelation is present if the Durbin-Watson statistic is below the low critical value. Autocorrelation can be ruled out if the Durbin-Watson statistic is above the high critical value, but below four minus the high critical value. It is inconclusive if the Durbin-Watson statistic falls in between the two critical values.

Q. Did you look for a value of two for the Durbin-Watson statistic when developing you models?

A. Yes.

Q. Does your residential sales forecast model past the Durbin-Watson test?

A. Yes.

Q. Have you applied this same analysis with the Durbin-Watson Statistic in your other models?

A. Yes. I have utilized the Durbin-Watson statistic in my other models, which I will discuss later on.

Commercial and Industrial Sales Model

Q. Please discuss PSEG LI’s commercial and industrial models.

A. PSEG LI divided the commercial and industrial, or C&I, customers into nine subsectors by the North American Industrial Classification System, referred to as NAICS. PSEG LI developed a regression model for each of the first eight subsectors for (1) manufacturing, (2) trade, transportation, and utilities, (3) leisure and hospitality, (4) financial activities, (5) information, (6) service, (7) education and health services, and (8) government. The forecast for the ninth subsector “miscellaneous” and is based on a trend and ratio analysis.

Q. What concerns do you have with the Company’s C&I models?

A. The Company’s C&I regression models have first order autocorrelation problems as they do not pass the Durbin-Watson test.

Q. Have you performed the Durbin-Watson test for PSEG LI’s C&I models?

A. Yes. My Durbin-Watson test results are shown on page 2 of Exhibit___(AL-5). The test shows that first order autocorrelation cannot be ruled out for six of PSEG LI’s C&I models. Three of PSEG LI’s C&I models are tested positive for autocorrelation and five are tested inconclusive. Of the five that are inconclusive, three of them have Durbin-Watson statistics closer to the failure boundaries. The fourth one is confirmed positive by a Q-statistic test, an alternative statistic test for autocorrelation. The result for the Q-statistic test is provided on page 3 of Exhibit___(AL-5).

Q. What are the consequences of autocorrelation with a regression model?

A. The ordinary least square, or OLS, method in the regression analysis rests on the assumption of zero autocorrelation. When this assumption is violated, the reliability of the reported regression results is overstated. The standard errors of the estimates of the regression parameters are significantly underestimated.

Q. What implications does first order autocorrelation have with using a regression model for forecast?

A. The regression model is not suitable to best predict electric sales. Because of significantly underestimated standard errors of the regression parameters, the confidence in the model is significantly reduced.

Q. Could autocorrelation of residuals of a model be remedied?

A. Yes. Autocorrelation can be removed by a generalized least square method. An autocorrelation parameter, or the estimated relationship of the residuals, is introduced to the model and estimated simultaneously with other model parameters. Such a model would have much better predictive power because, in addition to correcting underestimates of standard errors, the estimated relationship between residuals may be used to reduce forecasting errors.

Q. To what extent did the Company apply these remedies?

A. The Company’s forecast models are estimated by an OLS method, which does apply autocorrelation remedies.

Q. Do you have other concerns with PSEG LI’s C&I models?

A. Yes. Another concern is that some of PSEG LI’s C&I models failed the multicollinearity test.

Q. Which of PSEG LI’s C&I models have a multicollinearity problem?

A. PSEG LI’s leisure and hospitality model includes three economic variables that are highly correlated, GMP, personal income, and number of households. The financial activities model includes GMP and personal income that are highly correlated. As I discussed earlier for the residential sector, regional personal income is a major component of GMP and the two move in the same direction.

Q. Did you perform a multicollinearity test for these two models?

A. Yes. The results of a VIP test for multicollinearity are provided on pages 4 and 5 of Exhibit___(AL-5). For the leisure and hospitality model, the variances for the GMP per employment and income per customer variables are highly inflated. For the financial activities model, the GMP per customer and income per household variables have highly inflated variances.

Q. What consequences does multicollinearity have for a regression model?

A. As I discussed earlier, a model with high multicollinearity is not reliable because of inflated sampling variance and greater sensitivity to small data changes. The regression analysis is distorted by the high correlation among the explanatory variables, leaving little variations in electric sales to be explained by these included economic variables. As a result, individual coefficients of these economic variables cannot be estimated correctly and accurately. Ultimately, this reveals that the forecast model unreliable.

Q. Have you developed your commercial and industrial model?

A. Yes, I have. Similar to my residential model, my C&I model is a use per customer model and assumed in a log-linear regression functional form.

Q. Please describe your C&I sales model.

A. The dependent variable of my C&I sales model is sales per customer adjusted for a leap year factor. The explanatory variables include real electricity price, real GMP for Long Island, CDDs, and a dummy variable to capture the effect of Super Storm Sandy of 2012. The model has an overall high level of goodness of fit with an adjusted R-squared of 82 percent and a Durbin-Watson statistic of 1.66. The output of my C&I model and associated statistics along with the model forecasts are provided on page 5 of Exhibit___(AL-4).

Q. Why did you keep the price variable in the model when the statistical significance of the coefficient is below a commonly accepted level of 95 to 90 percent?

A. The price variable is very important in the model so it is included even though the statistical significance of the coefficient is a little lower than a commonly accepted level. The inclusion of electricity price is to preserve the model’s compliance with economic principles that the demand for a commodity is inversely related to the price of the commodity. Additionally, the coefficient of the price variable represents price elasticity of electricity demand, which can be used to estimate electric sales response to price changes. Furthermore, the statistical significance of the coefficient is still high with an acceptable level of more than 86 percent.

Q. Is autocorrelation accounted for in your regression analysis?

A. Yes. An autoregressive term was included during the analysis to account for the presence of first order autocorrelation in error terms. The Durbin-Watson test result was switched to negative after the remedy. More importantly, the included autoregressive term is utilized during the forecasting process, thereby reducing forecasting errors. As such, my C&I sales model is should be adopted because it is superior to PSEG LI's C&I models for reliability and accuracy.

Q. You have one forecast model for the entire C&I sector, while PSEG LI has nine models by NAICS sector. Does PSEG LI's revenue price model require C&I sales to be forecast by NAICS sector?

A. No. Only total C&I sales are needed as an input to the Company's revenue price out model. PSEG LI's forecasts by NAICS sector are aggregated into a forecast for one C&I sector for revenue price out, which was allocated to service classifications using historical ratios.

Customer Forecast Models

Q. Did PSEG LI develop regression models to forecast customer growth?

A. No. It developed its customer forecast based on trends in population and employment, as explained on page 24 of SRF Panel's testimony.

Q. What is the PSEG LI's projected residential customer growth?

A. The Company projects residential customer will grow at 0.25 percent annually for 2016-2018.

Q. What is PSEG LI’s forecast for commercial and industrial customer growth?

A. The Company forecasts commercial and industrial customers will grow at 0.3 percent for 2016, 0.2 percent for 2017, and 0.1 percent for 2018.

Q. Do you agree with the Company’s customer forecasts?

A. No. An econometric methodology is a preferred approach for forecasting number of customers. Using an econometric methodology, the relationships between customer growth and an economic demographic variable, such as population or employment, can be estimated objectively. An econometric methodology is also a transparent and verifiable process for customer forecasting.

Q. Have you developed an econometric model to forecast customer growth?

A. Yes. I again used the transfer function methodology that I discussed earlier to develop my customer forecast. The residential customer model includes the number of households as the economic variable. The commercial and industrial customer model has employment as the economic driver. Data for both economic variables were provided by the Company. The results of the estimated models and forecasts are provided on pages 2 and 4 of Exhibit___(AL-4).

Q. Why did you use the number of households instead of population as the economic variable in your residential customer model?

A. Population was tested in the residential customer model, but was determined statistically insignificant because of a small t-statistic. The number of households is statistically significant variable when it included in the model. As shown on page 2 of Exhibit___(AL-4), the model fits the historical data with very high adjusted R-squared of 0.999. The result shows that household formation in a service area has a direct impact on additions to residential electric customers.

Q. What is your forecast for residential customer growth?

A. As shown in Exhibit___(AL-3), residential customers are expected to grow by 0.4 percent in

2016 and 0.3 percent per year in the following two years. Commercial and Industrial customers are expected to grow by 0.4 percent in 2016, 0.2 percent in 2017, and 0.1 percent in 2018.

Q. To what degree does your customer forecast differ from that of PSEG LI?

A. My customer forecast is slightly above the Company's customer forecast, by less than a 0.1 percent.

Forecast Assumptions and Post-Model Calculations

Q. What is your data source of the predicted values and assumptions for the explanatory variables?

A. The predicted values of the electricity price and economic variables were provided by the Company through its response to IRs DPS-Preliminary-68 and DPS-SRFP-297, included in Exhibit___(AL-1). The electric price forecast was developed by PSEG LI. The original source for the economic variables is Moody's Analytics. The weather conditions are assumed normal, which are based on the latest 10-year averages of CDDs and HDDs.

Q. Have you prepared an exhibit to show your forecast assumptions?

A. Yes. My forecast assumptions are summarized in Exhibit___(AL-3).

Q. Why did you use a 10-year average methodology to determine normal weather conditions for electric sales forecast?

A. The 10-year average method puts more weight on recent weather data, which better captures the weather trend and continued climate changes. My method is consistent with previous decisions concerning sales forecast in recent electric and gas rate cases (Case 10-E-0362, Order Establishing Rates for Electric Services, issued June 17, 2011, page 14; Case 08-G-0888, Order Adopting Recommended Decision with Modifications, issued June 22, 2009, page 15.)

Q. Do you suggest that a 10-year based weather normalization method should also be used for peak load forecast?

A. No. The process and purpose of forecasting peak load are different from those of forecasting sales. In general, the peak forecast involves the use of a designed weather conditions, not normalized weather conditions. The design weather condition is determined from the historical data for peak producing weather conditions. For reliability purposes, uses of weather data for a 30-year historical period should continue. It is not difficult to distinguish the use of weather data for revenue forecasting purposes from reliability purposes.

Q. What method did PSEG LI use for weather assumptions?

A. PSEG LI's normal weather conditions are based on a 30-year average of CDDs and HDDs.

Q. How different are your 10-year based normal weather conditions from the Company's 30-year based weather conditions?

A. The number of the 10-year average annual CDDs is slightly lower than the number of the 30-year average by 0.6 percent. For HDDs, the number of 10-year average is 1.3 percent lower than the 30-year average. The assumption of smaller numbers of CDDs and HDDs leads to a lower sales forecast.

Q. Your sales forecast models are developed on an use per customer basis. Did you do any post-model calculations to come up with total sales for residential customers and total sales for commercial and industrial customers?

A. No. The econometric software I use provides total sales forecast directly.

Q. Did you make a post-model adjustment for 2016, which is a leap year?

A. No. A leap year adjustment is not required for the model forecast because an adjustment has been made in the forecasting process. As explained earlier in my testimony, a leap year variable was included in my forecast models and the assumed values of leap year variable for 2015-2018 are utilized in the forecasting process.

Q. PSEG LI used a calibration process to adjust its model forecasts to 2014 projected year end 2014 sales. What is the adjustment associated with the calibration process?

A. PSEG LI used a calibration process to align the model forecasted sales for 2014, which are on a basis of aggregated billing month sales, with booked sales for 2014, and a sum of estimated calendar month sales for 2014. In its response to DPS-SRFP-239, included in Exhibit___(AL-1), the Company explained that the 2014 calendar month sales are estimated with nine months of experienced sales for 2014.

Q. Is a recalibration procedure required for your model forecast?

A. No. Because my forecast models are developed using historical data through 2014 and the model forecast has already reflected the full year sales of 2014.

Q. Without a calibration adjustment, is your annual sales forecast representative of annual calendar month sales for the forecasting period?

A. Yes. Although my models are developed using historical annual data of billing month sales, the forecast should be representative of the annual calendar month sales. The differentials between billing month sales and calendar month sales for February through November would be eliminated when they are summed to the annual total. The differential will remain for December because sales of the current billing month do not include sales of the full calendar month. However, the shortfall has been compensated by sales of the previous December partially included in the current billing month of January, thereby leaving only a small year-to-year differential that may exist in part of calendar month of December. This year-to-year differential in December sales should be minimized with a weather normal assumption, expected minor increases in the number of customers, and flat sales for the forecasting period.

Adjustments for DSM Savings

Q. How was the impact of energy efficiency and renewable, referred to as EER, programs treated in your sales forecast?

A. I manually adjusted the model forecasts by deducting the incremental demand side management, or DSM, savings as result of EER programs and sales lost to cogeneration. They include DSM savings from anticipated EER programs and those that have not been reflected in my model forecast.

Q. What is the source of your DSM saving estimates?

A. I used PSEG's provided EER data to derive my DSM saving estimates for 2015-2018.

Q. What magnitude is your estimated DSM savings for 2015-2018?

A. My estimated incremental DSM savings for the LIPA system is 508 GWhs for 2016, 773 GWhs for 2017, and 1,019 GWhs for 2018. The estimates by sector for 2015-2018 are provided in Exhibit___(AL-2), in rows 13-16 and columns 2-3.

Q. Please describe PSEG LI's DSM saving projections.

A. PSEG LI's DSM savings are estimated based on evaluation reports and the targets of LIPA's existing EER programs. PSEG LI's DSM estimates also include a sales reduction they attribute to changes in building codes and appliance standards. As shown in Exhibit__ (SRFP-4), PSEG LI estimates that the system wide DSM savings are 804 GWhs for 2016, 1,119 GWhs for 2017, and 1,412 GWhs for 2018.

Q. How did you use the Company's provided data to derive your DSM saving estimate?

A. The Company provided DSM savings by customer classifications for 2014-2018. Since my model forecast has already reflected the actual sales for 2014, 171 GWhs, or a half of the DSM savings estimated for 2014, is subtracted from those estimated for 2015. The same calculation is applied for each year of 2016-2018. After these calculations, the incremental DSM savings are rebased to start in 2015.

Q. What DSM savings does your rebased projection for 2015 include?

A. It includes half of the annualized DSM savings estimated for each of 2014 and 2015.

Q. Why did you include one half of the DSM savings estimated for 2014 and 2015 for your 2015 DSM saving projection?

A. The Company's DSM savings for the full year 2014 are estimated based on evaluation reports, converted from the MW load reduced as result from energy efficiency equipment or appliances that are installed throughout the year. After one energy efficient appliance is installed, it takes 12 months to realize the full impact on electric sales. For simplicity, it can be assumed that EER equipment and appliances are installed evenly throughout the year and as result, one half of the annualized total impact would be realized by the end of current year and the other half would be realized in the following year. This assumption is consistent with the Company’s DSM saving estimate methodology, as shown in its response to DPS-UEE-237, included in Exhibit___(AL-1). As such, my estimated DSM savings include one half of the DSM savings associated with the 2014 installations that will be realized by the end of 2015.

Q. Did you make any adjustment other than rebasing the DSM savings for 2015-2018?

A. Yes, I made two adjustments to the rebased DSM saving estimate. One adjustment is to exclude a portion of the DSM savings that the Company said is attributed to improvements in building codes and appliance standards. I also propose that the remaining DSM saving estimate be reduced by 10 percent before applying it to my model forecast.

Q. Why did you exclude the Company’s estimated sales reduction for improvements in appliance standards and building codes?

A. Building codes and appliance standards are determined by national and state governments and changes are taking place gradually over time. The compliance to codes and standard is a slow process and requires workforce as well as product development. The gradual and slow impact should have been captured in actual electric sales as well as in the forecast.

Q. Do other New York utilities include codes and standards in their projections for DSM savings?

A. No. Utilities project their DSM savings based on EEPS program targets and performance. The EEPS programs administered by NYSERDA and utilities can be evaluated and reports are provided on a regular basis.

Q. Please describe the Company's estimated sales reductions due to changes in building codes and appliance standards.

A. PSEG LI includes an estimate of sales reductions that it attributes to changes in building codes and appliance standards. According to its response to IRs DPS-SRFP-238 and DPS-SRFP-329, these estimates contribute to sales reductions of 103 GWhs for 2016, 123 GWhs for 2017, and 143 GWhs for 2018.

Q. Do you agree with the Company's estimated sales reductions for codes and standards?

A. No. The targets that the Company used to calculate its DSM savings for codes and standards for 2014-2015 were included in a straw proposal for setting goals to reducing electricity usage by 15 percent statewide by 2015. These DSM savings targets are no longer part of the EEPS targets.

Q. How did PSEG LI develop its sales reductions for codes and standards for 2016-2018?

A. According to its response to DPS-SRFP-407, included in Exhibit___(AL-1), PSEG LI's assumptions for codes and standards are based on "informal discussions among peers within the energy industry" and information from the NYSERDA website, and the incremental growth in associated sales reductions was set internally.

Q. Does NYSERDA have a budget for advanced codes and standards programs?

A. Yes. NYSERDA has a SBC-funded program for statewide workforce development on improving codes and standards, but the program does not result in separately counted direct energy savings. Rather, energy savings resulting from training efforts would be examined through evaluations conducted on the associated end-use programs. In addition, the budget for this program is relatively insignificant and decreasing. The program’s funding accounts for a 3.3 percent of the NYSERDA’s annual budget for 2014-2015 and 1.5 percent for 2016.

Q. Please discuss your 10 percent adjustment to the Company’s DSM saving projections.

A. The 10 percent adjustment is made based on a trend analysis of my forecasts before DSM reductions. It indicates that the DSM-induced slower trend in electric sales has been partially captured by my forecast models.

Q. What does the trend analysis of your forecasts before DSM reductions show?

A. My forecasted sales growth before DSM reductions is an average 1.7 percent per year for 2014-2018. This rate is below the 1.9 percent annual growth registered in the 10-year period ending 2007 during which there were no DSM programs of the scale matching existing EER efforts. The annual DSM savings from LIPA’s existing programs range from 250 MWhs to over 300 MWhs for the past three years, which reduced total system sales by about 1.3 to 1.5 percent per year.

Apparently, my model forecast has reflected lower sales growth in recent years resulting from large scale of EER programs. As such, my model forecasts should not be reduced by the full amount of DSM savings as estimated by PSEG LI.

Q. How does PSEG LI's forecasted sales growth before DSM compare with the historical growth trend in LIPA's system?

A. PSEG LI's forecasted sales growth is close to the annual rate for the ten years ending in 2007. PSEG LI forecasts an average 1.9 percent annual growth in system sales before DSM savings for 2014-2018 with an adjustment factor of 0.06 percent. This factor was "to overcome the growth-reducing effects of embedded DSM," as explained in its response to DPS-SRFP-239, included in Exhibit___(AL-1).

Q. In GWhs for the LIPA system, how does your model forecast differ from the Company's model forecast?

A. My model forecast is below the Company's forecast by 824 GWhs or 3.8 percent for 2016, 1,020 GWhs or 4.6 percent for 2017, and by 1,122

GWhs or 5.0 percent for 2018.

Q. Did you adjust your model forecasted growth rates to compensate for the slower growth rates induced by the embedded DSM savings?

A. No, I did not. It is difficult to obtain accurate DSM saving estimates for the historical period. Adding inaccurate DSM saving estimates back to billed sales data would introduce significant errors and make it difficult to develop sales forecast models. In addition, another study would be required to estimate such an impact even if accurate historical data were available. I choose to adjust the projected DSM savings to compensate the already low sales growth rates predicted by my forecast models.

Q. What is your adjustment to the projected DSM savings?

A. My adjustment is 56 GWhs for 2016, 86 GWhs for 2017, and 113 GWhs for 2018. They account for less than one tenth of the model forecast difference between the Company’s and mine.

Q. How was cogeneration treated in your sales forecast?

A. Sales lost to cogeneration are treated in the same manner in my sales forecast as in the Company’s forecast. That is, estimated historical sales lost to cogeneration were added back to billed sales for model development and then subtracted from the model forecast. My sales forecast also reflect the Company’s estimated incremental sales reduction due to cogeneration.

Other Sales, Overview, and Risk to Forecast

Q. Have you developed a forecast model for other sales?

A. No. I accepted PSEG LI’s provided forecast for other sales and updated to reflect the 2014 actual sales data. Other sales, including sales to Brookhaven National Labs, Long Island Railroad, and street lighting customers, counts for about 3 percent of total sales in LIPA service area.

Q. What is your general assessment of sales forecast in LIPA’s service territory?

A. Slow population and economic growth in Long Island supports a forecast of moderate growth in electric sales in LIPA’s service territory. However, aggressive energy efficiency and renewable programs will dampen and even more than offset the forecasted growth. As such, under my forecast LIPA electric sales are expected to grow 1.4 percent annually in 2015 and 2016 and decline 0.5 percent annually in 2017 and 2018.

Q. How does your sales forecast compare with the economic growth anticipated in Long Island?

A. The economy of the LIPA service territory is expected to grow at significantly higher rates in the next two years compared with the previous three years. For example, real per capital personal income will grow at 3.7 percent compared to 0.6 percent over the past three years, and employment will grow at 2.0 percent compared with 1.2 percent over the past three years. My sales forecast is consistent with the relatively optimistic outlook of the Long Island economy as forecasted by Moody’s Analytics.

Q. How does your sales forecast compare to that of PSEG LI for the next two years?

A. My forecast is 151 GWhs or 0.7 percent above PSEGLI’s forecast for 2016. This highlights that my forecast is more reflective of the relatively optimistic outlook of the Long Island economy for 2015-2016 than PSEG LI's forecast.

Q. How does the economic outlook for the next two years compare with that for the following two years?

A. A slowdown of the economic expansion in the following two years is expected, but Moody's Analytics does not forecast a recession. As shown in Exhibit___(AL-3), the average growth of personal income is expected to decrease to 1.9 percent in 2017-2018 from 3.7 percent in 2015-2016 and growth in regional GDP will decline from 3 percent per year for the next two years to 1.9 percent for the following two years. The average growth rate in employment has a similar pattern, at 2 percent in 2015-2016 and less than 1 percent in 2017-2018. Personal income and Regional GDP are the two economic drivers of my forecasting models.

Q. What is your assessment of the risks to your forecast?

A. My forecast is subject to the risks of the economic forecasts provided by Moody's Analytics. As always, there are uncertainties in an economic forecast, which are affected by many factors. My sales forecast is also subject to the uncertainty that actual weather conditions are different from assumed normal weather conditions. For example, a warmer or colder than normal summer by 10 percent, as measured in total annual CDDs, may swing residential sales by 2 percent. A third factor is the uncertainty in the projections for DSM savings based on existing energy efficiency and renewable programs and new initiatives.

Q. Please summarize your recommendation.

A. I recommend that PSEG LI’s sales forecast be rejected because some of its models do not comply with economic principles or pass basic econometric tests. Further, PSEG LI’s estimates of sales reductions for DSM savings should also be adjusted. On the other hand, my forecasts for both sales and number of customers are based on econometric models. My forecast models follow economic principles and meet basic econometric standards. My forecast is based on a superior methodology, a weather forecast more reflective of the current trend, and appropriate treatment of DSM savings. I recommend that my electric sales forecast be adopted in this proceeding.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

JUDGE PHILLIPS: Next up, I believe we have the PSEG Ratemaking/Revenue Requirement Panel that was on the schedule.

MR. WEISSMAN: Your Honor, the direct testimony will be entered by affidavit. Believe it or not, in the time we have been working on this case one of the members has retired. We are still hoping to get ahold of that affidavit to submit by tomorrow. We apologize for that.

JUDGE PHILLIPS: Are we doing just the original or are we waiting until tomorrow?

MR. WEISSMAN: We can provide the Ratemaking Revenue Requirement Rebuttal Testimony at this time, which we reserve the first number for the direct testimony of that panel by request.

JUDGE PHILLIPS: For the rebuttal panel or the direct?

MR. WEISSMAN: The direct we reserve and for the rebuttal I can provide.

JUDGE PHILLIPS: We are reserving number 112 for the direct, and you will give me an affidavit now for the rebuttal that will be marked as 113; is that correct?

MR. WEISSMAN: Your Honor, with respect to the Ratemaking and Revenue Requirement Rebuttal Panel, I would like to present the affidavit of Gary Ahern, Joseph Trainor, Fritz Ferdinand, Louis DeBrino and Lisa Figliozzi who are submitting by this affidavit their Ratemaking and Revenue Requirement Rebuttal Testimony. That testimony consists of 23 pages plus the cover sheet. There are also three exhibits that are attached to that testimony identified on the exhibit list as Exhibit RR-REB-1 which is Exhibit 46, Exhibit RR-REB-2 which is Exhibit 47 and Exhibit RR-REB-3 which is Exhibit 48 (handing).

JUDGE PHILLIPS: On the basis of the affidavit that has been marked for identification as Exhibit 113, we would like to have copied into the record the Rebuttal Testimony of the Ratemaking and Revenue Requirement Panel submitted on June 10, 2015.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-____________

DIRECT PRE-FILED TESTIMONY
OF
RATEMAKING
AND
REVENUE REQUIREMENTS PANEL

Date: January 30, 2015

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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Ratemaking and Revenue Requirements Panel (the "Panel").

A. We are Gary S. Ahern, Joseph Trainor and Lisa Figliozzi.

Q. Mr. Ahern, please state your employer and business address.

A. I am employed by PSEG Long Island LLC ("PSEG LI" or the "Company") and my business address is 333 Earle Ovington Blvd, Uniondale NY 11553.

Q. In what capacity are you employed by the Company?

A. I am employed by the Company as Director of Finance at PSEG LI. In this position I am responsible for, among other things, regulatory filings on behalf of Long Island Lighting Company ("LIPA"), maintaining LIPA's Tariff, Electric Customer Rates & Pricing, PSEG LI Financial Statements, PSEG LI Accounting, PSEG LI Budgeting & Forecasting, billing and collections from LIPA, and non-utility billing on behalf of LIPA.

Q. Please summarize your educational background and professional experience.

A. Prior to assuming my position with PSEG LI, I was Vice President, U.S. Regulation and Pricing -- Gas Distribution for National Grid Corporate Services, LLC which provides engineering, financial, administrative and other technical support to direct and indirect subsidiary companies of National Grid USA. My duties included revenue requirements and pricing oversight for the U.S. gas distribution subsidiaries of National Grid USA, including National Grid's New York gas utilities The Brooklyn Union Gas Company, Keyspan Gas East Corporation and the gas operations of Niagara Mohawk Power Corporation, as well as Boston Gas Company, Colonial

Gas Company, and Essex Gas Company. I joined Brooklyn Union Gas Company (a predecessor company of National Grid KeySpan Corporation) in 1975 where I held a number of financial positions within Brooklyn Union, KeySpan Corporation and, most recently, National Grid. I worked in the Corporate Planning Department for Brooklyn Union as a financial analyst and was appointed to oversee Brooklyn Union's regulatory filings with the New York State Public Service Commission ("Commission" or "PSC"). From 1993 through 2001, I served as the Corporate Budget Director of Brooklyn Union and (beginning in 1998) for KeySpan Corporation. In 2001, I was appointed the Director of Finance for the Electric Business Unit, where I was responsible for providing financial services, controls and analysis to support the electric operating companies, including the LIPA contract, among other responsibilities.

In 1982, I earned a Bachelor of Arts degree in Business Management/Accounting from Saint Francis College. In 1986, I earned a Masters of Business Administration from Adelphi University.

Q. Mr. Trainor, please state your employer and business address.

A. I am employed by PSEG LI and my business address is One Hundred East Old Country Road, Hicksville, New York 11801.

Q. In what capacity are you employed by the Company?

A. I am employed by the Company as Senior Manager in Regulation and Pricing. My current responsibilities include rate case management, tariff management, customer pricing, and revenue reporting. I have held this position since September 2014.

Q. Please summarize your educational background and professional experience?

A. Prior to assuming my position at PSEG LI, I was employed by Black & Veatch from 1998 to 2014, most recently as a Principal – Management Consultant Division. While at Black & Veatch I provided consulting services to a host of investor-owned utilities in the areas of class cost-of-service analyses and modeling, statistical and comparative cost and operating analysis, revenue requirements modeling, load and sales forecasting, rate design, demand-side management ("DSM") and financial modeling. I am the architect of many DSM and cost-of-service models, having performed electric and gas cost-of-service and marginal cost-of-service projects for a variety of clients. I have performed minimum system and zero intercept studies in numerous states, as well as load research, weather normalization and load forecast studies. I have created models to calculate test year revenue requirements and to perform economic, rate and financial valuations of multi-jurisdictional utilities for the purpose of investment.

In addition to my utility and energy industry analytical skills, I also possess broader IT expertise including application programming and database management.

In the area of governmental entities, most recently, I was retained by the Guam Power Authority for their 2013 rate filing, which included managing internal and external legal counsel, reviewing and editing all testimony and data requests. I was also responsible for testifying in the 2013 Guam rate case on the subjects of revenue requirements, load research, cost of service and rate design. I have also provided consulting services for ratemaking and other proceedings and projects to the Kauai Island Utility Cooperative, the Philadelphia Gas Works, the Indiana Water Authority, and the Villages of Freeport and Rockville Centre on Long Island.

I hold a BS degree in Electrical Engineering from Manhattan College, New York (1993) and an MBA from Long Island University, New York (2003).

Q. Ms. Figliozzi, please state your name and business address.

A. My name is Lisa Figliozzi. My business address is One Hundred East Old Country Road, Hicksville, New York 11801.

Q. By whom are you employed and in what capacity?

A. I am Manager, Regulation and Pricing – PSEG LI. My current duties include revenue requirements oversight for PSEG LI and for LIPA.

Q. Please summarize your educational and professional background.

A. I joined Long Island Lighting Company (a predecessor company of KeySpan Corporation) in 1990. Since that time, I have held a number of financial and accounting positions within Long Island Lighting Company, KeySpan Corporation and, most recently, National Grid. I worked in the Corporate Budget and Planning Department for Long Island Lighting Company as a financial analyst and was promoted to Manager, LIPA Reporting in 1998 when Brooklyn Union merged with the Long Island Lighting Company. I supported regulatory filings and developed financial exhibits that were presented to the New York PSC, FERC, NYSERDA, and LIPA. From 2004 through 2005, I served as the Budget Manager of the Ravenswood generation power plant, which supplied twenty percent of New York City's power. In 2006, I was a functional team leader for Keyspan's Property Records software implementation project, and subsequently during the integration period with National Grid I was appointed the Manager of Plant Accounting. Plant Accounting was headquartered in Massachusetts, with offices in Buffalo, Syracuse, Glens Falls, Rhode Island and Long Island. I was responsible for centralizing Plant Accounting Operations on Long Island and providing asset accounting functions, including closing, financial and regulatory reporting, services, controls and analysis to support the US Operations, including the LIPA contract. In 2010 I assumed the role of Principal Analyst for Revenue Requirements of the New York gas companies for National Grid. In October 2012 I was selected as Manager of Regulation and Pricing supporting LIPA, which is my current role.

I hold a Bachelor of Science degree in Business Management/Finance from Long Island University (1989) and a Masters of Business Administration/Finance from Long Island University (1995).

Q. What is the overall purpose of the Panel's testimony in this proceeding?

A. We are presenting the revenue requirement in this case. We have developed that revenue requirement using the Public Power Model and based on Consolidated Budgets of PSEG LI and LIPA for the three years, 2016, 2017 and 2018 as required by the Amended And Restated Operations Services Agreement between Long Island Lighting Company d/b/a LIPA and PSEG Long Island LLC, dated as of December 31, 2013 ("OSA"). The process of developing and consolidating the budgets is explained by the Budget Panel. This testimony will explain how the PSEG LI and LIPA budgets were consolidated to develop the revenue requirement for each year of the Rate Plan, using the Public Power Model. Finally, we will discuss various automatic adjustment clauses that we recommend for approval by the LIPA Board of Trustees. The precise mechanics of those clauses will be presented in the testimony of Mr. Trainor on cost of service, rate design, and tariff issues.

Q. What is the revenue requirement for LIPA that the Panel has developed for the three years of the Rate Plan?

A. The proposed changes in LIPA's rates and charges, to become effective on January 1, 2016, are intended to support LIPA's financial stability, as discussed in the testimony of LIPA witness Falcone, and reflect PSEG LI's efforts to enhance and improve customer service and electric reliability, replace aging electric infrastructure, and create a more resilient, modern, and customer-responsive electric utility on Long Island while minimizing the rate impact on customers.

The annual increases in revenues for electric delivery that LIPA and PSEG LI are proposing are as modest as possible and in keeping with the requirement that rates be set "at the lowest level consistent with sound fiscal and operating practices . . . and which provide for safe and adequate service." The increases: approximately $72,748,000 effective January 1, 2016; $74,253,000 effective January 1, 2017; and $74,256,000 effective January 1, 2018, will result in a 2.0% increase effective on January 1, 2016; a 2.0% increase effective on January 1, 2017; and a 2.0% increase effective on January 1, 2018.[1] The proposed bill increase over the three-year period is roughly equivalent to the projected rate of inflation during this same period. The increases also follow a three-year delivery rate freeze. These increases are separate from the charges for fuel, purchased power, and some generation-related costs, which fluctuate and are collected through the Fuel and Purchased Power Cost Adjustment ("FPPCA").

Q. Is the Panel sponsoring any exhibits in support of its testimony?

A. Yes, we are sponsoring the following exhibit, which was prepared by or under the supervision of the Panel or one of the Panel's members that provide the details underlying the revenue requirement in each year of the Rate Plan:

1. Exhibit __ (RRP-1) entitled "2016-2018 Projected Operating and Capital Budgets" and supporting schedules for the projected rate years ending December 31, 2016, December 31, 2017, and December 31, 2018.

[1] The percentage increases are measured as a percentage of the total customer bill consistent with the LIPA Reform Act. If applied only to delivery charges, the percentage increases would be 3.8%, 3.9%, and 3.9%, respectively.

II. CONSOLIDATED BUDGETS AND THE RATE PLAN

Q. How did you begin your development of the Rate Plan for the three years, 2016, 2017 and 2018?

A. We began our development of the revenue requirement for those three years with the budgets for PSEG LI and LIPA. These budgets contained all the incoming revenue and outgoing expenses, and we adjusted these costs for additional cash income and deductions, necessary to derive an adjustment to the revenue requirement. An additional element to be considered was that PSEG LI's budgets were developed using GAAP accounting. As will be explained, because the Public Power Ratemaking Model is a cash-based model, adjustments to those figures were necessary to produce a Public Power revenue requirement.

Q. What adjustments were made to the consolidated budgeted income statement to derive the 2016-2018 revenue requirements?

A. As noted above, the Public Power Model requires adjusting the income statement to arrive at cash requirements that equal the revenue requirement, plus the desired coverage level after cash outlays have been met. The following adjustments were made to derive the cash approach: Non-Cash Expenses such as depreciation, amortization of acquisition adjustment, transition costs, asset retirement obligation, OPEBs and pensions, and rate case expenses were all eliminated from the revenue requirement and subsumed in the debt coverage requirement provided by LIPA. Cash Requirements such as the Nine Mile Point II decommissioning costs and the contribution to the pension trust were added back to the revenue requirement. The principal of and interest on LIPA's debt, bank fees and amounts for coverage all were discretely recognized in the revenue requirement.

Q. Please provide an example of how the Public Power Model would require an adjustment of an expense in the revenue requirement.

A. Consider the level of pension and OPEB expenses. PSEG LI, for example, receives an actuarial estimate of its pension and OPEB expenses on a GAAP basis. PSEG LI, however, is funding the pension based on the ERISA minimum amount, and this is the amount that LIPA will remit to PSEG LI under the terms of the OSA. Therefore, for the Public Power Model, pension expense in rates is the ERISA minimum funding amount and not the GAAP amount reflected on PSEG LI's books. A similar approach is used for OPEBs. Because OPEBs do not carry a minimum funding obligation in the same way that pensions do, OPEBs are recovered in rates on a "pay as you go" basis, and not the GAAP amount estimated by the actuary. LIPA recognizes that it will ultimately incur higher OPEB "pay as you go" expense in the future and has chosen to establish an OPEB Account to prefund these costs within its existing Operating Expense Fund. That prefunding, however, will be made out of funds available for debt coverage, as defined in the LIPA Board Resolution adopting the OPEB account and can be explained in more detail by LIPA witness Thomas Falcone.

Q. Have you incorporated the effect of Utility 2.0 on the revenue requirement in this case?

A. No. At this juncture, there is not a fully approved Utility 2.0 plan in place for LIPA. PSEG LI made two proposals for a Utility 2.0 plan, one in July 2014 and a subsequent one in October 2014. The first proposal called for PSEG LI to fund the Utility 2.0 programs and to earn a utility rate of return on them. That plan was rejected by LIPA. The second proposal called for essentially the same projects and funding levels but, instead, proposed that LIPA would pay for the plan. That filing has not been approved by LIPA either. Because the funding proposals made by PSEG LI have not been adopted, this filing excludes the effects of Utility 2.0.

Q. Does the exclusion of Utility 2.0 effects from this filing indicate that PSEG LI no longer supports the Utility 2.0 programs?

A. No, it does not. The LIPA Board has approved $2 million for additional program development for Utility 2.0 in 2015, and the operating and capital budgets also include projections for $13.3 million and $3.9 million, respectively, of Utility 2.0 program implementation expenditures during 2015. The 2015 budgets approved by the LIPA Board state that Utility 2.0 implementation expenditures will be brought to the Board for separate approval upon receipt of a recommendation by the Department of Public Service ("DPS"). PSEG LI strongly supports Utility 2.0 and will continue to make the case that the DPS should be encouraged to recommend the Utility 2.0 solutions to the LIPA Board in the ongoing Utility 2.0 proceeding.

III. RATEMAKING MODEL AND PLAN

Q. Please describe the ratemaking model that has been employed in developing the Rate Plan.

A. We have adopted the Public Power Model as the basis for setting rates in this case.

Q. Why have you chosen the Public Power Model?

A. We chose that approach for several reasons. First, LIPA's executives expressed a strong preference for using the Public Power Model and requested its use in this proceeding. Based on that expressed preference, we discussed with counsel whether that approach would be consistent with the applicable ratemaking standard imposed under the LIPA Reform Act. Under the Public Authorities Law (Section 1020-f(u) rates must be set "at the lowest level consistent with sound fiscal and operating practices of the authority and which provide for safe and adequate service." In addition to that general standard, Section 1020-k, subdivision 6 states that LIPA's "rates, fees or charges [must be] sufficient to pay, the costs of operation and maintenance of the facilities owned or operated by the authority, payments in lieu of taxes, renewals, replacements and capital additions, the principal of and interest on any [of LIPA's debt] obligations . . . as the same severally become due and payable, and to establish or maintain any reserves or other funds or accounts required or established by or pursuant to the terms of [LIPA's debt]." Under Section 3-b of the Public Service Law, the DPS must review any rate request by LIPA to "ensure that the authority and the service provider provide safe and adequate transmission and distribution service at rates set at the lowest level consistent with sound fiscal operating practices" and "[t]he department's recommendations shall be designed to be consistent with ensuring that the revenue requirements related to such rate review are sufficient to satisfy the authority's obligations with respect to its bonds, notes and all other contracts." We concluded that the use of the Public Power Model was consistent with the law; indeed it seemed to us that the law counseled its use. We then examined the OSA for guidance on the applicable ratemaking standard. It states (Section 6.2(B)) that:

> The preliminary Three Year Rate Plan shall be designed in a manner to ensure that, if adopted by LIPA and subject to the forecast assumptions specified therein, LIPA and the Service Provider are able to provide safe and adequate transmission and distribution service in the Service Area at rates which are (i) at the lowest level consistent with sound fiscal operating practices and (ii) sufficient to generate revenues necessary to satisfy LIPA's obligations to its LIPA's bondholders, lenders and other creditors and contract counterparties including the Service Provider.

Again, the Public Power Model appeared best suited to the ratemaking standard set forth in the OSA. Based on our review of these sources and discussions with counsel, we determined that the use of the Public Power Model would appropriately satisfy the requirements of the law and the OSA.

Second, LIPA presented us with a report by its financial advisor that also recommended and supported the use of the Public Power Model for ratemaking in this case. We reviewed that report and independently verified that the rates of many large publicly owned utilities were set using the Public Power Model.

Third, we independently examined that model and concluded that it was appropriate to use. Mr. Trainor, in his experience as a consultant, has dealt extensively with public power utilities that used the model to set their rates, and we concluded that the Public Power Model is appropriate for setting rates in this case.

Q. Please explain the public power approach to rate-setting.

A. LIPA is offering its own testimony in this case and will also demonstrate why the Public Power Model is superior from a ratemaking perspective for use in setting LIPA's rates. Briefly, the Public Power Model differs from the traditional rate base/rate of return model used for investor owned utilities ("IOUs") in the following, significant ways. First and foremost, IOUs' rates are based on the concept of a rate of return on rate base. Public power utilities' rates typically do not employ a rate base/rate of return calculus. Instead, public power utilities' rates reflect the requirement that a public authority like LIPA is generally required to recover through rates the principal and interest on its debt after expenses and other contractual obligations have been satisfied. Another significant difference between the Public Power Model and the traditional IOU model is that rates are set on a "cash" basis for the public power utility. For example, for IOUs, depreciation expense is specifically allowable in rates. For public power utilities depreciation expense, as a non-cash item, is not explicitly recovered in rates. Instead the return of capital represented by depreciation expense for an IOU is recovered by a public power utility through the amortization of its debt. For an IOU, pension and OPEB costs are calculated on an accrual basis according to GAAP and are collected in rates. In New York, such costs are specifically collected under the Commission's Policy Statement on Pensions and OPEBs. Under the Public Power Model being used in this filing, the GAAP level of those costs are subsumed under LIPA's bond coverage and only a minimum ERISA pension funding level is explicitly reflected in rates. Another significant difference, of course, is that there are no private equity holders in a public power utility; the customers, i.e., the public, are the owners of a public power utility. Consequently there is no return on equity required. Moreover any "equity" that is on the books of a public power utility is actually ratepayer contributed funds that support capital additions. There is no balancing of interests between investors and customers required because the only investors are bond investors, whose returns on investment are fixed. There are no equity holders to assume investment risk. For these and many other reasons, the Public Power Model differs significantly from the model used to set rates for an entity that is "for profit." Again, where utility service is provided by a public power entity, the customers are, essentially, the owners.

Q. Is there a way to encapsulate the Public Power Model?

A. Yes, the fundamental ratemaking philosophy for public power utilities is to provide safe and reliable service at rates that recover all costs, including the cost of servicing its debt which includes payments of interest and payments for amortizing the debt's principal amount. If there is a margin in excess of current costs, this margin, or "coverage," may be used to fund a portion of the utility's infrastructure investments in lieu of relying exclusively on debt to fund capital projects, and may also be used to provide a "cushion" of safety to fund unexpected expenses, capital additions, accrued expenses or a diminution of revenue.

Q. Is this a common ratemaking methodology for public power utilities?

A. Yes. Public power utilities serve many small and rural communities. There are also several major metropolitan areas like Long Island that are totally or partially served by locally-controlled municipal utilities, including: Austin, TX, Jacksonville, FL, Los Angeles, CA, Memphis, TN, Omaha, NE, Orlando, FL, Phoenix, AZ, Sacramento, CA, San Antonio, TX and Seattle, WA. It is Mr. Trainor's experience that the public utility model is typically used to set rates for these entities.

Q. Are you aware of the model that the Commission in New York uses to set rates for the utilities that it regulates?

A. Yes. The PSC's 1977 Statement of Policy on Test Periods in Major Rate Proceedings (17 NYPSC 25-R) provides that rates are set based on a normalized, historical test period that is then adjusted to reflect operations in the first year that rates are to be in effect.

Q. Is it appropriate to use that policy to set rates here?

A. We do not believe so. Under the 1977 Policy Statement, the historic test period must reflect "operating results, with normalizing adjustments, for a twelve-month period expiring at the end of a calendar quarter no earlier in time than 150 days before the date of filing." There are several reasons why it is not possible to present such a historic period. First, the LIPA Reform Act mandates that this rate filing be made no later than February 1, 2015. Consequently, information for Calendar Year 2014 would not have been available in time to make this filing, let alone examine that data in order to "normalize" various expenses and activity levels. Second, reaching back to a period earlier than January 1, 2014 for historical information would have been futile. In this case, PSEG LI only began operating the LIPA system on January 1, 2014 subject to the OSA. Prior to that date, National Grid ran the system under a Management Services Agreement ("MSA") which was a very different structural arrangement than the OSA. Consequently, the operations and functions performed by PSEG LI differ in significant ways from the operations of the previous operator, National Grid, rendering historical information relating to National Grid's operations largely inapplicable. Third, even if information prior to January 1, 2014 were relevant, the books and records of National Grid for that historical period, although the property of LIPA, were not reasonably accessible for preparation of this case. Furthermore, LIPA's records do not reflect the necessary level of detail to prepare a test year because virtually all O&M costs were recorded under the management fee. Consequently, it is neither possible nor practicable to attempt to construct a historic test year upon which to base a fully forecasted rate year. In this case, we use budgets to project LIPA's revenue requirement three years into the future for the Rate Plan envisioned by the LIPA Reform Act and the OSA.

Q. Was it possible to use a mixture of actual and projected 2014 costs to set rates?

A. No. Given the statutory obligation to file this case on February 1, 2015, it was not possible to collect 2014 costs, examine and audit them and then normalize them to remove or adjust abnormalities in time to file this case and then make projections for the remaining months. Moreover, those costs would not have been appropriate for a variety of reasons. Calendar year 2014 was a transition year for PSEG LI and LIPA in which operations were still being transformed from operations under the MSA to the new operating model under the OSA. Although our T&D function is the closest to the organization that existed prior to January 1, 2014, it still has significant differences from 2013, which will continue being realized in 2014 and beyond. The

Customer Services function is very different from that in existence prior to January 1, 2014, as the gas and electric businesses were separated and additional functions were added and continued to be added and reorganized in 2014 and beyond. The Business and Shared Services segment of the business is nothing at all like it was in 2013, or even 2014, as the Transition Services Agreement ("TSA") function provided by National Grid continued throughout 2014. Examples of these differences abound in the testimony of the various PSEG LI panels. Operations in 2014 are therefore not representative of a full year of normal operations. Rather than using unrepresentative historical operating data, the Rate Plan filed in this case is based on comprehensive, consolidated budgets which are described by the Budget Panel as well as by testimony on behalf of the three major operating divisions of PSEG LI.

Q. Does the law or the OSA contain any standard by which LIPA's rates should be set?

A. Yes. Section 6.2(B) of the OSA provides that "[t]he preliminary Three Year Rate Plan shall be designed in a manner to ensure that, if adopted by LIPA and subject to the forecast assumptions specified therein, LIPA and the Service Provider are able to provide safe and adequate transmission and distribution service in the Service Area at rates which are (i) at the lowest level consistent with sound fiscal operating practices and (ii) sufficient to generate revenues necessary to satisfy LIPA's obligations to its LIPA's [sic] bondholders, lenders and other creditors and contract counterparties including the Service Provider." Section 5.2(B)(8) of the OSA further requires that "[t]he Operating Budget and the Capital Budget and the related ServCo staffing levels for each Contract Year shall be designed to be adequate in both scope and amounts to reasonably assure that the Service Provider is able to carry out the related Operations Services in accordance with the Contract Standards and have a reasonable opportunity to earn Incentive Compensation under the Performance Metrics." In developing our revenue requirement, including PSEG LI's budgets, we have been cognizant of those requirements.

Q. Do budgets form the basis of the three-year Rate Plan referred to in the OSA?

A. Yes, they do. As the Budget Panel explains, they first developed budgets for the operation and maintenance of the LIPA system by PSEG LI. Next, LIPA presented its budgets to PSEG LI for the three years of the Rate Plan, and we consolidated the PSEG LI budgets with the LIPA budgets to produce the Revenue Requirement which is based on and produces the "Consolidated Budgets" required by the OSA.

IV. <u>CONSOLIDATED BUDGETS AND RATES</u>

Q. Previously the Panel mentioned that the revenue requirement was developed using consolidated budgets, which include PSEG LI budgets, "PSEG LI managed expenses," and LIPA expenses. Are the consolidated budgets subject to long-term contracts now managed by PSEG LI that were entered into before PSEG LI became the manager?

A. Yes, a major portion of the consolidated budgets that make up the Revenue Requirement is subject to the terms of long-term contracts entered into well before January 1, 2014. For example, PSEG LI is now managing LIPA's power supply and fuel contracts, and is administering the PILOTs (these are "payments in lieu of taxes" which were property and revenue tax payments previously made by LIPA's predecessor, LILCO).

Q. Are increases in PILOT payments constrained by law?

A. Yes. PILOT payments on T&D property have been projected to reflect increases of 2% over 2014 PILOT payments, in accordance with the provision of Public Authorities Law §1020-q limiting such increases to no more than that amount. Were it not for that provision of the law, we would be seeking an adjustment mechanism to account for PILOT increases (or decreases). We note, however, that some 2015 property tax bills appear to contain increases greater than the 2% limitation and discussions are ongoing as to the appropriate response to such property tax bills.

Q. Did PSEG LI participate in the development of LIPA's budgeted costs, especially assumptions regarding LIPA's debt?

A. No. Although we had extensive and ongoing discussions with LIPA officials, the essential elements of cost in the LIPA budgets, such as debt cost assumptions, bond coverage assumptions and LIPA's own cost levels were developed and prepared by LIPA. They were then provided to PSEG LI for consolidation with our budgets pursuant to the requirements of the OSA. We then worked with LIPA officials to ensure that the revenue requirement prepared for this case properly reflected the costs and assumptions provided by LIPA. Witnesses on behalf of LIPA will provide the rationale for the decisions made with respect to the LIPA budgets.

Q. Are there other factors besides long term contractual costs that drive the revenue requirement in this case?

A. Yes. LIPA received grant income in 2014 and 2015 which in large measure, was composed of federal grants to LIPA for disaster recovery related to Superstorm Sandy, Hurricane Irene and other declared weather events. These costs, however, have now been fully reimbursed and grant income will effectively decrease in the 2016 rate year and beyond.

Q. Do capital additions affect LIPA's revenue requirement?

A. Yes, but not directly as they do in an IOU's rate case.

Q. Please explain.

A. In an IOU's rate case, capital additions are translated directly into rate base additions and then to the revenue requirement associated with a larger rate base. Here, however, capital additions to LIPA's system might initially be funded by short term lines of credit which are then replaced by long term debt. The costs associated with that debt, both as to the timing of the financing and the terms, including interest rates (which, because LIPA debt is tax-exempt, are lower than IOU-issued debt) and amortization periods, as well as refinancing decisions and efforts to securitize a portion of the debt, are within the discretion of the LIPA Board of Trustees and, in the case of securitized debt, actions of the State Legislature. Consequently, we are guided in the revenue requirement we develop by the assumptions provided by LIPA as to its debt related costs over the three-year Rate Plan period.

Q. Do the LIPA budgets also reflect LIPA's decisions to levelize certain costs, charges and revenue requirement issues?

A. Yes, they do. For example, LIPA has expressed a position on the appropriate amount of debt services coverage on its bonds which, in LIPA's opinion should be at a level of 1.15 times in 2016; 1.20 times in 2017; and 1.25 times in 2018 on LIPA's debt. LIPA's witness, Mr. Falcone, will support this coverage amount, what expenses are properly subsumed under coverage and why LIPA believes the investment community requires such coverage levels. LIPA is also responsible for the timing and refunding of its debt issuances and can address the effect that activity has on the annual revenue requirement.

Q. Did this Panel review those decisions by LIPA?

A. We did not, as those decisions by LIPA are based on matters that are uniquely within LIPA's knowledge and control. Consequently, they are presented by the witnesses LIPA is presenting in this filing on those subjects.

V. <u>REVENUE REQUIREMENT</u>

Q. Have you developed an Exhibit that sets forth the Revenue Requirement for the three years of the Rate Plan?

A. Yes. Exhibit __ (RRP-1) presents the electric delivery base rate revenue requirement with supporting Schedules for the Rate Years ending December 31, 2016, 2017 and 2018, as well as presenting the approved budget for 2015.

Q. Please describe the information shown on Schedule A of Exhibit __ (RRP-1) entitled "Revenue Requirements."

A. Schedule A describes LIPA's projected revenues at current rates and the expenses and adjustments made to obtain the revenue requirement using the Public Power Model previously discussed.

Q. Please describe Schedule A-1 to Schedule C-1 of Exhibit __ (RRP-1).

A. These Schedules contain the revenues, expenses, and supporting information for the Revenue Requirement presented in Schedule A.

VI. AUTOMATIC ADJUSTMENT CLAUSES

Q. Is the use of automatic adjustment clauses a common feature of ratemaking in New York?

A. Yes, it is. In its recent Order approving the Consolidated Edison rate settlement, the Commission noted that such

> reconciliation provisions…are designed to hedge the risk that actual costs and expenses can vary from the levels forecast to establish revenue requirements. Such provisions are typical components of multi-year rate plans where the required period of forecast introduces risk that cost can vary materially from expected levels. Reconciliation provisions are appropriate for material costs such as property taxes, interference, pensions/OPEBs and environmental remediation cost that are difficult to forecast with certainty and are largely beyond the direct control of utility management.

Case 13-E-0030, et al, Consolidated Edison Company of New York, Inc., Order Approving Electric, Gas and Steam Rate Plans In Accord With Joint Proposal, issued February 21, 2014, pp. 43-44.

Q. Is the use of automatic adjustment clauses appropriate in this case?

A. Yes it is. We note in particular the Commission's view that the employment of such adjustment clauses "protects both ratepayers and utility investors' interests by ensuring that neither cost over-recovery nor under-recovery occurs." Here, of course, there is no balancing of ratepayers' and investors' interests because LIPA has no investors in the sense that IOUs have equity holders. If anything, the need for LIPA to recover unanticipated costs is even greater than that of IOUs, which are required and able to bear some element of risk in light of their opportunity to earn a return.

Q. What automatic adjustment clauses are you proposing should be implemented for LIPA, in addition to the existing Fuel and Purchased Power Cost Adjustment and other adjustment mechanisms currently in LIPA's tariff?

A. We propose a Delivery Service Adjustment. In addition, we support continuation of the Revenue Decoupling Mechanism ("RDM") that has been noticed to the LIPA Board of Trustees for approval in 2015.

VII. REVENUE DECOUPLING MECHANISM ("RDM")

Q. Please explain why LIPA's rates should include an RDM.

A. We note that adoption of an RDM has been noticed to the LIPA Board for 2015. If that RDM is approved by the LIPA Board, we support its continuation for the duration of the Rate Plan. Utility rates are designed to produce a revenue requirement based upon an assumption of revenue for the year or years for which rates are being set. Achieved revenue, however, can vary from that forecast for a variety of reasons, such as weather, economic conditions and conservation efforts.

Q. How does weather affect electric sales?

A. For a summer peaking utility such as LIPA, which has a significant air-conditioning load, a warmer, muggier summer than normal can inflate revenue above forecasted amounts, while a cooler, drier summer can result in lower-than-anticipated revenue collection.

Q. Can economic conditions affect revenue?

A. Events such as recessions, economic downturns and other economic conditions that reduce disposable income in its service territory can affect a utility's sales.

Q. How does conservation adversely affect revenue?

A. Conservation by its very nature results in fewer kilowatts sold. For example, every incandescent bulb that is replaced by an energy efficient light bulb reduces electric sales.

Q. Does LIPA promote energy efficiency?

A. Yes. LIPA has a considerable array of energy efficiency programs and is considering implementing the Utility 2.0 program proposed by PSEG LI that will further drive energy efficiency. These programs, however, are designed to reduce consumption. Unless LIPA is made whole for its sales lost to conservation by some other direct payment, it is actually penalized for promoting conservation.

Q. Is there another reason for employing an RDM?

A. Yes. Fundamental ratemaking equity requires that rates be based on the sales achieved. If LIPA fails to achieve the sales anticipated it will fall short of meeting its required debt service coverage and perhaps even fall short of meeting its expenses. This is particularly problematic for a public entity like LIPA, where there are no shareholders to absorb the business or regulatory risk of variable revenue; any shortfall in anticipated revenues can only be made up by future customers, that is, exactly those customers who will make up for a revenue shortfall under the proposed RDM.

Q. Are RDMs common in New York for investor-owned electric companies?

A. Yes, they are quite common. In April 2007, all major electric and gas utilities in New York State were directed by the Public Service Commission to file proposals for true-up-based revenue decoupling mechanisms, so as to eliminate barriers to utility promotion of energy efficiency, renewables technology, and distributed generation. Cases 03-E-0640 and 06-G-0746, Potential Electric and Gas Delivery Rate Disincentives, Order Requiring Proposals for Revenue Decoupling Mechanisms (issued April 20, 2007). To the best of our knowledge, since that time most if not all of the major New York electric utilities have employed an RDM in their rate structure.

Q. Are you presenting the mechanics and proposed tariff language for an RDM?

A. No, we assume that the mechanics of the RDM that we expect to be adopted in early 2015 by the LIPA Board of Trustees will continue to govern this adjustment mechanism.

VIII. <u>DELIVERY SERVICE ADJUSTMENT ("DSA")</u>

Q. Are you also proposing a change to the recovery of certain costs under the new DSA?

A. Yes, we are. We are proposing that the DSA permit an annual reconciliation to the following cost categories: (a) power supply costs; (b) major storm costs; and (c) debt service costs.

Q. Please describe the power supply costs that would be subject to the DSA.

A. We are proposing that the costs related to the National Grid power plants, including certain peaking plants (Far Rockaway, Glenwood and Port Jefferson) and Nine Mile Point II be recovered based on a true up with the levels of expense currently forecasted in rates. The mechanics of the clause itself are discussed by Mr. Trainor in his testimony.

Q. Are you also proposing to recover variations in major storm costs in the DSA?

A. Yes, we are. As with weather, storm costs are difficult to forecast with any degree of accuracy. The Rate Plan includes a set level of storm restoration costs. There is, consequently, a significant likelihood that LIPA will over- or under-collect storm cost expense in any given year. The storm cost reconciliation element of the DSA will assure that ratepayers pay LIPA's actual storm costs in a given year, no more, no less. Again, Mr. Trainor will discuss the mechanics of storm cost reconciliation in his testimony.

Q. Finally, the proposed DSA also includes a mechanism to track debt costs. Please explain why LIPA requires such an adjustment mechanism.

A. We are proposing this adjustment mechanism because the amounts and timing of LIPA's debt offerings cannot be forecasted precisely. Furthermore, LIPA has built significant projected refinancing savings into its projected debt service costs for 2016, 2017, and 2018, which may or may not be realized as budgeted. Consequently, it would be preferable for LIPA to recover its actual cost of debt when it becomes known.

Q. Is this clause appropriate in this case?

A. Yes. Because LIPA's rates are not being set on a rate base/rate of return method, the DSA permits LIPA a current recovery on debt costs (interest cost and principal amortization), which are key drivers of the revenue requirement in the public power model.

Q. Why is it necessary to implement a debt cost recovery mechanism if capital budgets have been generated for 2016, 2017 and 2018?

A. While it is true that capital budgets have been generated for those years, the translation of those budgets into debt, including the precise terms and cost rates and amortization provisions of that debt, is more difficult to forecast. That is especially true in this case where LIPA has made assumptions about debt cost savings in the form of additional issues of securitized bonds to replace existing bond issues and other bond refunding savings. The DSA permits LIPA to calculate and recover or refund any deviations from the forecasted debt service costs in a given rate year.

Q. If LIPA is permitted to securitize additional amounts of its existing debt; would those savings be captured by the DSA?

A. Yes, they would be, as the DSA is intended to capture differences in LIPA's total debt service costs in any given rate year from the levels forecasted in the case. Consequently, if debt costs are reduced by a securitization of existing debt, those savings would be captured by the DSA. As with the other adjustment mechanisms, the mechanics of the debt cost recovery portion of the DSA are discussed by Mr. Trainor in his testimony.

Q. Does this conclude the Panel's direct testimony at this time?

A. Yes, it does.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-00262

REBUTTAL TESTIMONY
OF
RATEMAKING AND REVENUE REQUIREMENTS PANEL

Date: June 10, 2015

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I. WITNESS QUALIFICATIONS

Q. Please state the names of the members of this Ratemaking and Revenue Requirements Rebuttal Panel (the "Panel").

A. We are Gary S. Ahern, Joseph Trainor, Fritz Ferdinand, Louis M. DeBrino and Lisa Figliozzi.

Q. Have you previously submitted pre-filed testimony in this proceeding?

A. Yes, except for Fritz Ferdinand, as members of the Ratemaking and Revenue Requirements Panel, and as a member of the Storm Response Panel (Mr. DeBrino), and our witness qualifications are set forth in those testimonies.

Q. **Mr. Ferdinand, please state your employer and business address.**

A. I am employed by PSEG LI and my business address is 175 E. Old Country Road, Hicksville, New York 11801.

Q. In what capacity are you employed by the Company?

A. I am employed by the Company as a Senior Analyst in Regulation and Pricing. My current responsibilities focus on all aspects of the revenue requirements model and assisting in the budget process. I have held this position since August 2014.

Q. Please summarize your educational and professional background.

A. I joined KeySpan Corporation (a predecessor company of National Grid) in 2005. From 2005 to 2014, I held several accounting/finance positions. My first position in the utility industry was at KeySpan Energy Trading Services department. I was responsible for the preparation of Premium Accounting remittances and invoicing on option contracts. Also, I was in charge of the disbursals and reversals journal entries related to margin calls and settlements.

At the end of 2006, I assumed a role in the Fixed Assets department. I have developed and assisted in the preparation of policies and procedures on Asset Retirement Obligations (AROs), work order life cycle, unitization, and retirements. I have interfaced with engineering, project management and operation organizations regarding a variety of topics in the areas of accounting for capital construction for LIPA and National Grid. Furthermore, I provided support as needed for regulatory rate proceedings for Brooklyn Union Gas, Keyspan Energy Delivery Long Island, Boston Gas Company (including the former Essex Gas Company) and Colonial Gas Company. In 2011, I joined the Cash Accounting department at National Grid. I was actively involved in the implementation of the new Cash processes in SAP. I have worked with different groups within Finance/Accounting and IT departments to prepare policies and procedures for the Cash group. I handled the tasks of cash clearing accounts, and prepared schedules for year-end audits. I proposed and reviewed monthly adjusting entries to record interest, bank fees, recurring ACH credits, outgoing wire transfers, and returned checks.

In addition to my experience in utility and energy industry, I have had Accounting/Finance functions in other industries encompassing auditing, taxation, compensation, general ledger, Accounts Payable (A/P), and Accounts Receivable (A/R). I hold a BS degree in Accounting from Molloy College, New York (2005) and an MBA from Dowling College, New York (2015).

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. We will present the consolidated revenue requirement after considering the recommendations of the Staff of the Department of Public Service ("DPS Staff") and other parties. We will further demonstrate that certain forecasts in the filing will become known and measurable at points in 2015 and again in 2016. We are, therefore, proposing a late 2015 update, and a "second stage" update submission to the LIPA Board of Trustees in late 2016 so that known and measurable numbers can be incorporated into the rate changes that become effective on January 1, 2017 and January 1, 2018, respectively. Finally, we will present rebuttal testimony on the inflation forecast, productivity adjustment, and the issue of straight time labor billed to storms.

III. OVERALL REVENUE REQUIREMENT

Q. Have you developed an exhibit to explain the differences between the revenue requirement contained in the initial filing on January 29, 2015 and the revenue requirement currently being sought by PSEG LI and LIPA?

A. Yes. Exhibit ___RR-REB-1 shows the projected revenues and overall rate requests for the three years of the rate plan, 2016, 2017 and 2018. As can be seen, the overall revenue requirement has changed from increases of 2% per year on total revenue to increases of 1.6%, 1.7% and 1.8% in the years 2016, 2017, and 2018, respectively, as will be explained. Exhibit ___RR-REB-2 provides the detailed adjustments required to determine the revenue surplus or shortfall. It supplements Exhibit___RR-REB-1.

Q. Have you developed an exhibit to explain the differences between the revenue requirement that was presented by PSEG LI on January 29, 2015 and that presented by the DPS Staff in its revised filing on June 8, 2015, which replaced its filing of May 14, 2015?

A. Yes. DPS Staff's Policy, Overview and Revenue Requirement Panel has presented an overall revenue requirement exhibit in its revised Exhibit___PORR-3, with explanatory notes for various adjustments they made. We have used Staff's exhibit, as corrected in its submission of June 8, 2015, as our starting point for an exhibit that presents our revised revenue requirement for the three years of the rate plan. Our exhibit points out corrections to the DPS filing, adjustments for updated cost information, adjustments by DPS Staff, in both its original and revised submissions, with which LIPA and PSEG LI agree, and adjustments made by the DPS Staff with which PSEG LI and/or LIPA disagree. This information is presented in our Exhibit___ RR-REB-3.

Q. Based on the corrections and updates of LIPA and PSEG LI, what is the current revenue requirement?

A. Exhibits __ (RR-REB-1, RR-REB-2, and RR REB-3) present the electric delivery base rate revenue requirement with supporting Schedules for the Rate Years ending December 31, 2016, 2017 and 2018. The cumulative rate request for each rate year is: approximately $60.0 million, effective January 1, 2016; $123.8 million, effective January 1, 2017; and $191.2 million effective January 1, 2018. This equates to annual increases of $60.0 million on January 1, 2016, $63.8 million on January 1, 2017, and $67.4 million on January 1, 2018, respectively.

Q. Do you have an overall observation about the revenue requirement developed by the DPS Staff?

A. Yes. In its revised submission of June 8, 2015, DPS Staff proposes rate increases of $20.5 million on January 1, 2016, $67.2 million on January 1, 2017, and $79.7 million on January 1, 2018, respectively, subject to updates that will be addressed in our discussion below on a second stage submission. We note that the DPS Staff's revenue requirement in 2016 is lower than PSEG LI's revenue requirement by $17.9 million to reflect a higher level of sales than we believe is reasonable. The rate increase is also reduced by DPS Staff's lower capital budgets, which reduce LIPA's debt service costs. As a general matter, we think it should be obvious that rates should be set in this three-year rate plan proceeding based on the forecasts that are most consistent with the evidence. Setting rates based on, for example, overly optimistic sales forecasts increases the probability that rate resets on January 1, 2017, 2018, and 2019 will be positive. The remainder of the DPS Staff's reduction in 2016 relates to adjustment of approximately $20 million to PSEG LI operating expenses. PSEG LI strongly disagrees with these adjustments, as explained by the various panel testimonies that were filed on June 4 and 5, 2015.

IV. <u>CORRECTIONS AND UPDATED COST INFORMATION</u>

Q. Are there any corrections that need to be made to the PSEG LI filing?

A. Yes. There are two corrections. As the DPS Staff correctly noted, PSEG LI double-counted Nine-Mile Point 2 decommissioning costs in its original rate plan filing.

PSEG LI is accepting the correction of approximately $-1.1 million for each year 2016, 2017, and 2018.

Another item is also associated with Nine-Mile Point 2. Since the date of the rate filing, a decommissioning study by Exelon Energy resulted in a lower Asset Retirement Obligation (ARO) caused by lower inflation rates and different assumptions. The forecasted accretion levels should be adjusted downward by approximately $-1.3 million for 2016, $-1.3 million for 2017, and $-1.4 for 2018.

Q. Is there other cost information that should be updated prior to the decision in this case by the LIPA Board of Trustees?

A. Yes. The Power Supply Agreement and Property Tax Payments in Lieu of Taxes ("PILOTs") should be updated in late 2015 to take into account known changes. PSEG LI filed property tax PILOTs in rates, assuming that they would grow by 2% per year, as indicated in the LIPA Reform Act. The latest property tax bills received from certain municipalities indicate increases higher than the 2% cap. PSEG LI and LIPA are reviewing these greater-than-expected increases, and the overall impact is unknown at this time, so LIPA is requesting that any increases above the two percent property tax cap over the prior calendar year be updated later this year. The second update being proposed in mid-2015 affects the National Grid Power Supply Agreement, which contains personnel costs for operating and maintaining the Long Island generation plants. Under this long-term contract, LIPA's responsibility for pensions and other post-employment benefits ("OPEBs") is under scrutiny at the Federal Energy Regulatory Commission ("FERC"), which has jurisdiction over the

Power Supply Agreement. As the outcome of that discussion is not known and has not been incorporated into our rate plan submission, it, too, would be an appropriate item to be updated if possible prior to the determination of this matter by the LIPA Board of Trustees.

V. SECOND STAGE COMPLIANCE FILING

Q. Are you proposing a second stage submission of costs in this rebuttal testimony?

A. Yes, we are. LIPA's witness Mr. Falcone has identified several cost categories that will become known and measurable by the end of 2016, and which should be recognized and incorporated in the delivery rates for implementation with the rate change slated to take effect on January 1, 2017 and January 1, 2018. PSEG LI agrees.

Q. Are second stage filings common in multi-year rate plans?

A. Yes, they have often been used by the New York Commission and other regulatory commissions to capture future cost estimates when they become known and measurable. The sole purpose of the second stage procedure envisioned here is to replace forecasted costs with actual costs when known.

Q. What cost categories are appropriate to include in the second stage compliance filing?

A. It would be appropriate to include known changes to LIPA debt costs; T&D property tax and PILOT payments; and union wage increases.

The first is meant to capture the cost rate on the USDA debt (securitized debt) that LIPA plans to issue in the summer of 2016, changing interest rate assumptions on LIPA's fixed debt issued in 2016 and variable interest rate assumptions for LIPA's variable rate debt. The actual schedule of debt service and corresponding savings resulting from the expected 2016 UDSA offering will be known and measurable later in 2016 and can be substituted for the estimated amounts that were used to set rates for calendar years 2017 and 2018. Also, any new fixed rate debt issued to support capital expenditures will be known and measurable by mid-to-late 2016. Lastly, as recommended by the Department, LIPA would update it variable rate debt assumptions and future fixed rate debt assumptions to the latest available actual information.

The second category of costs proposed for the second stage update is up-to-date information regarding T&D property tax and PILOTs. To the extent they are known and predictable, the actual property tax and PILOT bills and escalation rates should be substituted for the estimated bills and be incorporated in the 2017 and 2018 delivery rates.

PSEG LI's contract with its union workers will expire in November 2016. At this time a placeholder using PSEG LI's estimate of inflation of 2.5% was used to forecast the new union contract rate. DPS Staff improperly employed a lower rate of 1.9% for union wages in 2016 and then forecasted a lower rate of inflation of 2.1% in 2017 and 2018, which they applied as a proxy for the new union contract rate. Given that the actual union labor rates will be known and measureable in November 2016, those union labor rates should be incorporated in the base rates to be effective on January 1, 2017 and January 1, 2018.

Q. Does DPS Staff appear to agree with this proposal?

A. Yes. In their recent filing of June 8, 2015 the DPS Staff notes in the testimony of the Policy Overview and Revenue Requirement Panel (at pp. 37 and 38) that, although LIPA debt costs, the union contract and property taxes were forecasted in the rate plan filing, "it is preferable to have base delivery rates reflect the most accurate cost forecast available" and, therefore, these costs could be updated with actual costs for rate years two and three when they become known in late 2016.

Q. Please explain how such an update of known costs should be implemented for inclusion in base rates that become effective on January 1, 2017 and January 1, 2018.

A. The update procedure should be a ministerial matter. The actual cost of the LIPA debt is a matter of record and is calculable by LIPA's finance organization. The current collective bargaining agreement will run through November 12, 2016. Any increases attendant to re-negotiation of that agreement will be known upon its expiration. Finally, actual property tax PILOT bills for 2016 will be known at that time. It is proposed that these costs be provided to the LIPA Board of Trustees, with the tariff leaves necessary to implement the requisite base rate changes resulting from the costs, in sufficient time so that they can be adopted at the Board's December meeting.

VI. INFLATION ADJUSTMENT

Q. Did PSEG LI's budgets for 2016, 2017 and 2018 include an inflation adjustment?

A. Yes, they did. As explained in the testimony of the Budget Panel (p. 13):

> The 2016, 2017 and 2018 budgets were escalated for specific factors such as inflation, wage, salary and benefit increases and known activity level changes such as placing the tree-trim and maintenance on optimal cycles, adding employees where necessary and reflecting additional known increases or decreases to costs and projects

The general escalation rates used for union labor were 2.5%, for management salaries 3.0%, for fringe benefits 6%, for insurance 7%, and for non-labor and affiliate transactions 3% for 2015 through 2018. As explained above, however, discrete activity level changes were forecasted, along with known or reasonably forecasted changes.

Q. Did DPS Staff agree with this methodology?

A. No. The Panel (at page 7) used a different measure of inflation and applied it to the 2015 budget levels of O&M expense, as follows:

> Using 2015 as the base year, the forecast GDP IPD inflation rate is 1.94% for 2016 and 2.1% for 2017 and 2018, respectively. We then applied these factors to PSEG LI's 2015 expenses to arrive at the forecasted 2016, 2017, and 2018 rate year expense levels. The escalating factors were applied to the inflation adjusted expenses which were also adjusted for Staff's operation and maintenance adjustments.

According to DPS Staff, this resulted in "a reduction of operations and maintenance expense of $6.95 million in 2016, $4.93 million in 2017 and $5.73 million in 2018."

Q. Do you agree that it is appropriate to apply an inflation factor to all elements of O&M expense such as DPS Staff has done?

A. No. The DPS Staff applies a 1.9% limit on union wages in 2016 and 2.1% in 2017 and 2018, and then applies an additional productivity adjustment on top of that. We have additional concern with the DPS Staff's blanket inflation approach. For union benefits, the PSEG LI Panel stated that:

> the cost increases that were used for the administrative fees associated with benefits programs were escalated based on vendor contracts and fee agreements in place. With regard to medical and dental claims, we used a 6.6% increase for medical and a 6.7% increase for dental.

Where cost increases are known, or reasonably capable of projection, such as here, there is no need to resort entirely to an index, as DPS Staff has done, especially one as low as Staff's. This is especially true for medical costs, since it is well known that those costs have increased at many times the overall rate of inflation in the past, and PricewaterhouseCoopers' Health Research Institute projected that medical costs would rise 6.5% in 2014 and projects an increase of 6.8% in 2015. Given the historical rate of medical inflation, DPS's Staff's application of the 1.9% inflation rate to medical benefits is unreasonable, and inconsistent with the cost recovery procedures under the Amended and Restated Operations Services Agreement between Long Island Lighting Company d/b/a LIPA and PSEG Long Island LLC, dated as of December 31, 2013 (the "OSA").

Q. Were PSEG LI's management, administrative, supervisory and technical ("MAST") employees' salaries escalated at the rate of inflation?

A. No, they were escalated by the Wages, Salary and Benefits Panel at an annual rate of three percent for each year of the three-year rate plan as explained by the Wages, Salary and Benefits Panel on page 14. As the Wages, Salary and Benefits Panel explained (at page 12):

> PSEG LI's compensation philosophy is to measure and set a competitive total cash compensation opportunity (base salary plus variable pay) to levels found at other companies for similar roles and responsibilities. The variable portion of total compensation is considered pay at risk, in that it must be re-earned each year based on meeting pre-determined goals and operating targets.

In fact, the variable pay component of a MAST employee's salary is determined, in large part, by the metrics under the OSA. As the Wages, Salary and Benefits Panel pointed out (p. 13), PSEG LI's Performance Incentive Plan ("PIP") for MAST employees is designed with 60% of the award determination linked to performance against the PSEG LI Balanced Scorecard, 30% attributed to the PSEG LI business plan operating earnings, and 10% to the PSEG-wide strategic goal known as "People Strong." The Balanced Scorecard is based on reliability, safety, operational measures, and adherence to budgets, which are the primary metrics applicable to PSEG LI under the OSA. This is also in line with performance incentive plans that the NY Public Service Commission has endorsed in the past because they are aligned with ratepayer benefits. Here, again, however, DPS Staff would constrain the recovery of cost forecasts that are reasonable, restrained and wholly in keeping with the parameters of the OSA.

Q. Did the DPS take issue with PSEG LI's compensation plan or suggest another measure of compensation?

A. No, they did not. The Staff simply applied its forecasted inflation rate across the board to MAST salaries.

Q. Did the Staff also apply its forecasted inflation rate to MAST employees' benefits?

A. Yes.

Q. Do you agree with that approach?

A No, we do not. MAST employees' medical and prescription drug plans were projected by the Wages, Salary and Benefits Panel to increases for 2016 – 2018 at an annual cost increase of 6.6%, assuming no changes to employee contributions or plan design based on actual costs. Dental costs were projected for 2016, following the expiration of the existing vendor contract and based on the actual six months of claims experience presented, assuming increase of 15% based on an existing agreement for 2016, and increases for 2017-2018 projected at an annual rate of 6.7%. These increases are three times the inflation rate used by Staff and are in line with the actual increases experienced to date.

Q. Are there reasons to assume that the increases projected in the Company's filing were conservative?

A. Yes, as the Wages, Salary and Benefits Panel points out, the Affordable Health Care Act ("AHCA"), in 2018, may impose a 40% excise tax on our health plans. The projections that were contained in the Company's filing do not factor in this tax or the impact of the AHCA on our benefit program.

Q. Based on the above, is the DPS Staff's application of the GNP Implicit Price Deflator forecast of inflation to the Company's O&M to project increases during the Rate Plan likely to provide for rate recovery of the actual costs that PSEG LI will pass through to LIPA under the OSA?

A. No, it is not. Even if it is determined to use the Staff's forecast of inflation, it should only be applied to the union wage forecast in 2017 and 2018 and to other elements of cost that are not discretely forecasted. It should neither be applied to union benefits forecasts nor to the MAST salaries or benefits forecasts, nor to any cost element that has been separately forecasted and justified.

VII. PRODUCTIVITY ADJUSTMENT

Q. Did PSEG LI make a productivity adjustment to its proposed budgets for 2016, 2017 and 2018?

A. Yes we did. The productivity adjustment was a cap imposed by PSEG LI management on the totality of labor and non-labor increases forecasted in our budgets. PSEG LI applied an overall general productivity adjustment of $ 626,774 to 2016, $1.9 million to 2017 and $4.7 million to 2018, although organizations such as Transmission & Distribution embedded productivity within their base budgets, as explained in T&D Operations Panel Rebuttal Testimony for Bulk Electric Power.

Q. Did the DPS propose to impose a different productivity adjustment on PSEG LI's budgets?

A. Yes. The Staff Inflation, Productivity and Management Audit Panel ("Panel") proposed to impute the Commission's so-called "standard" productivity adjustment of one percent of the sum of labor and benefits expenses, applied to offset total O&M expense for each of the three rate years. As the Panel notes, the result of the productivity adjustment is to reduce the revenue requirement by $1.7 million in 2016 and $455,000 in 2017. IPMA Panel, p. 9. DPS Staff states that "'[i]n rate year 2018 the Company exceeded the standard and therefore no adjustment is warranted."

Q. Is the standard productivity adjustment warranted in this case?

A. We do not believe so. As noted above, PSEG LI did present discrete productivity savings in the case and DPS Staff has recognized this. Additionally, there are other productivity savings imputed to the case that DPS Staff has not recognized. For example, the T&D Operations Rebuttal Panel noted well over $600,000 of annual savings relating to an under-representation of the staffing needs for the new definition of the Bulk Electric System. This, alone, would obviate 1/3 of DPS's productivity reduction in 2016 and all of it in 2017. Furthermore, DPS Staff conceded that PSEG LI's productivity adjustment exceeded DPS's in 2018 but the DPS Staff did not give credit to PSEG LI in its methodology. In fact the productivity savings level filed by PSEG LI in 2018 was $-4.7 million, which is more than DPS proposed figures for 2016 and 2017 combined. PSEG LI believes that 2018 should be adjusted upward to be consistent with the approach used by the DPS in 2016 and 2017, to $2.7 million. This adjustment is reflected in DPS Staff's workpaper but not flowed into its summary of adjustments.

Q. Are there other reasons why the productivity adjustment is inappropriate here?

A. Yes. Since shortly after the adoption of the forecasted rate year in its 1977 Policy Statement on Test Years in Major Rate Proceedings, the Commission has made an imputed productivity adjustment to the projected O&M expenses of investor-owned utilities in New York. The explicit purpose of this adjustment is to impute productivity gains to an investor-owned utility in order to drive efficiencies. See Consolidated Edison Company of New York, Inc., Order Setting Electric Rates, Case 08-E-0539, 2009 WL 2448034 (April 21, 2009) (explaining that, if there were additional productivity gains over the 1% level, the Company would have the incentive to capture them in the short run, which would benefit ratepayers for the long term, and noting that "limiting the productivity imputation to 1% would leave the Company with some minimal upside earnings potential."). The Commission has realized that, for an investor-owned utility, any productivity savings would be retained by its shareholders. LIPA, however, is not an investor-owned utility. It has no shareholders and its owners are the public – essentially its customers. Consequently, the efficiency incentive behind the productivity adjustment, i.e., the ability of shareholders to retain any efficiency savings, is not present in LIPA's case.

Q. Isn't it true, however, that LIPA is operated by PSEG LI, which does have shareholders?

A. Yes, PSEG LI has shareholders, but its operation is governed by the OSA, which contains a complex set of operating requirements, along with strict operating metrics and punishments and incentives applicable to PSEG LI's operation of the LIPA system.

Q. In your view, does the OSA negate and obviate any need to impute an artificial disallowance of one percent of labor and benefits as an efficiency incentive?

A. Yes. The 1% so-called "productivity" adjustment is really nothing more than a disallowance of PSEG LI's projected labor, benefit, OPEB and pension costs. Here, however, the only basis on which costs may be disallowed lies in the OSA. The OSA contains a complex set of metrics, containing incentives and penalties that are described in the testimony filed earlier in this proceeding by the Metrics and Safety Panel. Those metrics drive, among other things, the incentive payments described in OSA section 5.1 C. The so-called "productivity adjustment" should not be injected into the carefully structured arrangement of the OSA which, itself, governs the entirety of PSEG LI's performance incentives and disincentives.

Q. Do you agree with the DPS Staff's calculated revenue requirement impact of the inflation and productivity adjustment?

A. No. Even if one were to agree with these DPS Staff adjustments, they are calculated incorrectly because they fail to take account of the different treatment of pensions and OPEBS under the Public Power Model. DPS Staff's adjustments were applied to the GAAP costs calculated for PSEG LI's labor and benefits but fail to take into account the fact that LIPA's rates use ERISA funding for Pensions and cash accounting for OPEBS, thereby overstating the adjustment. At the very least, then, the productivity adjustment, if it were to be adopted, should only be applied to the pension and OPEB expense actually used to set rates under the Public Power approach.

VIII. STRAIGHT TIME LABOR CHARGED TO STORMS

Q. Are you also addressing the recommendations of the DPS Staff Delivery Service Adjustment and Storm Reserve Panel ("DSP Panel") regarding charging straight time labor to storms and the recognition of certain expenses incurred in preparing for storms that fail to materialize?

A. Yes. The DPS Staff Panel (at p. 23) states that "LIPA and PSEG LI failed to distinguish whether they made adjustments for straight time labor costs that are already being recovered in base rates" [and] "recommend[s] that only incremental costs be charged to the storm reserve account." We understand these concerns but will show that the practice by which LIPA is charged for storm related work is consistent with the OSA and charges costs appropriately for storm expenses. We also acknowledge the DPS Panel's concern that preparation work for anticipated storms that fail to achieve the expected storm threshold should be billed to the storm account in appropriate circumstances, and will explain why we agree with the DPS Panel's proposed solution.

Q. In order to frame the issue, is the definition of "storms" important?

A. Yes. There are two different storm event definitions – the one governed by the terms of the OSA, which dictates when storm events become chargeable to the LIPA storm budget; and second, the "PSC major storm" definition, which sets forth criteria that are used by all IOUs in New York (and PSEG LI) to identify outage data that is to be excluded from a utility's calculation of reliability statistics.

There is a clear distinction between these two definitions. While each defines particular storm events, there is no direct correlation between the two, as they are being used for very different purposes. The definition set forth in the OSA is a contractual, financial arrangement between LIPA and PSEG LI. The DPS Staff Panel recognizes that the definition of a storm event used by LIPA and PSEG LI under the OSA differs from the definition of a major storm used by the DPS in calculating reliability statistics. The DPS Panel acknowledges on page 22 that the treatment of storms recognizes that "PSEG LI and LIPA … follow the definition of a 'Storm

Event' defined in the OSA as an event where at least 15,400 customers are interrupted or at least 150 jobs are logged in each case within a 24 hour period."

Q. Does the DPS Staff Panel acknowledge that the categories of costs that are chargeable to storms are contained in the OSA?

A. Yes. DPS Staff recognizes (p.23) that "[c]hargeable costs [to the storm reserve] specified in the OSA include, but are not limited to, straight time labor, non-capitalized costs, etc., which the Panel believes to be reasonable."

Q. Although the DPS Staff Panel concedes that straight time is appropriately charged to the storm reserve and that the costs are reasonable, the Panel states (p. 23) that it is "concerned with the treatment of straight time labor costs and the manner in which storm event costs are reconciled with respect to straight time and recommend that only incremental costs be charged to the storm reserve account." Do you agree with this recommendation?

A. No, although we understand the DPS Staff's concerns, we believe that the ratemaking treatment of straight time storm expense proposed in this rate plan properly takes into account the operation of the OSA with respect to storms and is entirely appropriate

Q. How is straight time storm labor addressed in the rate plan?

A. In developing the OSA, PSEG LI and LIPA recognized that storm response is a common occurrence on Long Island and, consequently, an appropriate part of PSEG LI's normal, straight time labor expense would be spent responding to storms. The PSEG LI budget process allocates straight time labor and benefits into the following categories: O&M; Capital; Storms; FEMA; and assessments that clear to O&M and capital. Only T&D personnel are permitted to bill straight time labor costs to LIPA during a "storm event," since all other personnel's straight time is fully contained within base O&M budgets. All labor and associated fringe benefits and taxes have been accounted for in LIPA's revenue requirement, including the straight time labor amount that is budgeted to Storms in a normal year.

Q. As noted, in its testimony at page 23, the DPS Staff Panel recommends that only incremental costs be charged to the storm reserve. Is this a reasonable limitation?

A. No. If straight time is not properly charged to storms, the OSA is not being followed and time actually spent responding to storms will not be recovered.

Q. If straight time labor expense has already been allocated in rates between storms and O&M, won't charging additional straight time expense to the storm reserve result in an over recovery?

A. No. In a year where there are significantly more major storms than usual, T&D employees are required to spend a larger portion of their straight time addressing storm-related work, and their base work, normally done in those straight time hours, will not be completed. Therefore, the allocation of straight time to storms when the storm work is being done prevents the storm work from eating into the original base budget. This feature of the OSA allows PSEG LI to collect the cost of both the additional storm work and original base budget work that was delayed due to the storm. The only way that LIPA can be made whole and complete the original budgeted amount of base work is to charge additional straight time to the storm reserve. The base work on the T&D system can then be covered by overtime and contractors because the straight time work was being charged to storms.

Q. The DPS Staff Panel has "recommend[ed] that PSEG LI file a report with DPS within 30 days after a storm event where costs were charged to the storm reserve… reconcile[ing] labor costs recovered in base rates to the labor costs charged to the storm reserve." The DPS Staff Panel claims that "[t]his will preclude double counting." Is that a reasonable recommendation?

A. A reporting system might have merit if several facts were taken into account. First, if such a report were deemed desirable, PSEG LI will need 90 days following a storm to provide the DPS with a reconciliation of storm related labor. In order to provide the DPS with accurate and verifiable data, we will need to allow for time to close our books. If, for any reason, there were delays in processing work orders/timesheets, the data may flow into the next reporting period. In addition, we need time to review, analyze and investigate charges that may need clarification. Providing a reconciliation of all storm related labor and overheads will require a 90 day period in order to ensure for the completeness of the report. Second, any such reports should not "morph" into a systemic reporting system. A few spot reports, randomly selected, should be both sufficient to inform DPS Staff that storm accounting is being properly managed and that no storm-related costs are being reflected twice in rates.

Q. Does the DPS Staff Panel recognize that PSEG LI may incur costs in anticipation of a storm event that does not materialize?

A. Yes. PSEG LI appreciates DPS Staff's recognition that PSEG LI has sole responsibility for emergency preparedness and more importantly, that there are significant challenges in forecasting weather and balancing the proper level of preparation from a risk perspective. Oftentimes with the prediction of significant storm activity, there is a potential for storm preparedness activities to incur significant costs for storms that do not qualify as reimbursable storm events when actual weather is less severe than predicted. PSEG LI goes to great lengths to make appropriate decisions related to the level of pre-storm preparation activities based on the predicted weather event. While such decisions are based on sound judgment and years of experience, there still exists the potential for actual storm activity to be less than anticipated, potentially leaving PSEG LI with significant costs that it cannot recover from the LIPA Storm Reserve because they do not qualify as storm events under the OSA. In that case, PSEG LI must charge the costs to O&M expense, placing undue pressure and associated risk on PSEG LI's ability to meet the OSA metrics targets of attaining the O&M budget when it is forced to absorb significant storm preparation costs that cannot be billed to the Storms account.

Q. Did the DPS Staff Panel recommend a protocol that might address this problem?

A. Yes. The DPS Staff Panel states (at page 26) that they will examine all preparatory storm costs incurred by PSEG LI for storm events that do not materialize as predicted. The Panel goes on to state that "[f]ollowing this examination, DPS may, if necessary, make formal recommendations to the LIPA Board of Trustees as to the reasonableness of those costs prior to authorization for payment given by the LIPA Board." PSEG LI appreciates the DPS Staff Panel's recommendation and agrees that such a review mechanism would help to mitigate some of the risks PSEG LI incurs when planning for storm events that ultimately do not materialize as predicted. Under the OSA, in a year of significant non-qualifying events (or a large non-event that occurs late in the fiscal year), the Company's ability to meet its O&M budget metric targets will be severely compromised because costs that should be charged incrementally to storms, but cannot be when the storm does not ensue, put strains on the budget and, as described above, on PSEG LI's ability to perform its normal workload within contractual limits. Accordingly, PSEG LI supports the DPS Staff Panel's suggestion to review future non-qualifying events and the reasonableness of the costs incurred, and to make recommendations to the LIPA Board of Trustees for potential recovery as storm expenses. PSEG LI will work with the DPS Staff and LIPA Staff to implement this recommendation.

Q. Does this conclude your rebuttal testimony?

A. Yes, at this time.

JUDGE PHILLIPS: The next panel by affidavit is PSEG Storm; is that correct.

JUDGE VAN ORT: Is that your Storm Response Panel?

MR. WEISSMAN: Correct, Your Honor. There was only Direct Testimony from the Storm Response Panel of Mr. DeBrino and Mr. Massaro filed on January 30, 2015. It is consisting of 17 pages and a single exhibit. I am checking the list for where that exhibit falls. It is Exhibit SRP-1-ERP Redacted. It's Exhibit 64 consisting of 415 pages. That was submitted, again, on January 30, 2015. I would like to approach the bench with the affidavit supporting that testimony and exhibit.

JUDGE PHILLIPS: Approach.

MR. WEISSMAN: (Handing).

JUDGE PHILLIPS: The affidavit of the Storm Response Panel has been marked for identification as Exhibit 114. On that basis, the Pre-filed Direct Testimony of the Storm Response Panel will be copied into the record as though given orally.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-____________

DIRECT PRE-FILED TESTIMONY
OF
THE STORM RESPONSE PANEL

Date: January 30, 2015

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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Storm Response Panel (the "Panel").

A. We are Louis M. DeBrino and Robert J. Massaro, Jr.

Q. Mr. DeBrino, please state your employer and business address.

A. I am employed by PSEG Long Island ("PSEG LI," or "Company") and my business address is 175 E. Old Country Road, Hicksville, NY 11801.

Q. In what capacity are you employed by the Company?

A. I am Manager, Emergency Preparedness of PSEG LI, a position I have held since January 2014. In this position, I oversee the development, maintenance and execution of PSEG LI's emergency preparedness which provides for a coordinated response during major storms and other system emergencies. I am charged with maintaining a constant readiness of our company-wide Emergency Response Organization ("ERO"), including assigning and training personnel for restoration assignments; creating and conducting storm preparedness drills and exercises; interfacing with New York State Department of Public Service ("DPS") personnel on emergency preparedness regulatory matters; coordinating and communicating emergency response planning activities with local and state government officials, emergency operations centers (Nassau County, Suffolk County, New York City and New York State), first responders and other emergency response organizations; representing PSEG LI within the North Atlantic Mutual Assistance Group ("NAMAG"); participating in calls related to the request and provision of mutual assistance resources; developing storm reports and conducting "After Action

Reviews"/critiques for major events; and directing delivery of high level technical expertise and functional support for the Outage Management System ("OMS") and core applications across Electric Operations.

Q. Please state your professional experience and educational qualifications.

A. From August 2012 to December 2013, I served as Executive Advisor to the President, Long Island Power Authority ("LIPA") Jurisdiction at National Grid, where, among other tasks, I provided input and consultation to key organizational business strategies and decisions, worked with the Long Island Transmission & Distribution leadership team to execute and deliver on annual business plan objectives and performance metrics and coordinated/led various special projects and represented National Grid on various task forces and at other meetings.

From April 2010 to July 2012, I was Director, Strategic Initiatives at National Grid where I actively supported LIPA's Request for Proposal ("RFP") process for the new Operations Services Agreement to replace the Management Services Agreement, providing required input, leadership, and guidance from RFP response through award phase. I layed a lead role in developing employee communications regarding the RFP process, providing ongoing visibility of RFP efforts and ensuring timely employee engagement. I also assumed a lead role in preparing post-storm communications including Tropical Storm Irene "After-Action Review," Report to the Public Service Commission, LIPA Board of Trustee presentations, Senate testimony and responses to numerous data and information requests from elected officials, towns, and other municipalities. Prior to that time, I held positions of increasing responsibility at

National Grid and its predecessor companies KeySpan and Long Island Lighting Company ("LILCO") in both the Operations and Customer Service organizations. I began my career at Grumman Corporation, Bethpage, New York in 1988 as an Engineer, Electronic Counter Measures.

I hold a Bachelor of Science, Electrical Engineering (1987) and a Master of Business Administration with a concentration in Marketing & Finance (1990) from Rensselaer Polytechnic Institute, and a National Incident Management System ("NIMS"), ICS-100 & ICS-200 Certification from the Federal Emergency Management Agency ("FEMA") (September 2014).

Q. Mr. Massaro, please state your employer and business address.

A. I am employed by PSEG LI and my business address is 15 Park Drive, Melville, NY 11747.

Q. In what capacity are you employed by the Company?

A. Since January 2014, I have been employed as Project Manager in the Customer Service Group. My responsibilities include implementing and developing projects associated with Emergency Response Preparedness and Communications. In this position, I have researched, developed, and tested to create an Emergency Response Escalation Tracker. I am also responsible for organizing, preparing, presenting, and training PSEG LI employees and municipalities on the Emergency Response Escalation Tracker. In addition to project management responsibilities, I manage the On Bill Recovery Loan program, assisting with billing inquiries and requests from the

New York State Energy Research and Development Authority along with weekly, monthly, and quarterly reporting.

Q. Please state your professional and educational experience.

A. From November 2012 to December 2013, I was a Program Manager for National Grid where I was responsible for implementing and developing the trade ally and business market program for LIPA. From January 2010 to November 2012 I was a Program Manager responsible for implementing and developing energy efficiency programs for LIPA in the LIPA service territory for residential new construction and multifamily buildings. In addition to program management responsibilities, I was responsible for developing financial documents, compiling information regarding financials and assisting in implementing programs to achieve and surpass various goals of the organization. I started work for National Grid as a Project Manager in April 2008 working on energy efficiency projects. Prior to that time I held various positions with other companies upon graduation from college.

I hold degrees in Marketing from Providence College (2007) and a Master of Business Administration from Dowling College (2011).

Q. What is the overall purpose of the Panel's testimony in this proceeding?

A. All Long Islanders are interested in how we respond to large scale storms. That awareness and sensitivity to the need for a robust response to storms has been incorporated into our mission statement, which expresses our commitment: "[t]o build an industry leading electric company dedicated to providing our Long Island and Rockaways customers with exceptional customer service, *best-in-class reliability* *and storm response*, as well as a strong level of involvement in the communities in which we live and work" (emphasis supplied). In fact, "Enhancing the Storm Response Process" is one of the four overall Strategic Objectives of PSEG LI. The purpose of this Panel's testimony is to outline and explain the plans and protocols that have been put in place to respond to the storms that affect Long Island, as well as our ability to stand ready to respond to other catastrophes. Additionally, we will share information on some of the enhancements that have been adopted as a means of improving the overall customer experience during storm response events. Because our Emergency Response Plan ("Plan," or "ERP") is required by regulatory mandates, and our Plan is part of a separate process before the DPS, this testimony is being provided only for informational purposes. Nevertheless, because this information is of concern to LIPA, our customers and other stakeholders, we believe it is important in this case to provide the Plan and describe its major elements. We want LIPA, our regulators, customers, elected officials, first responder partners and other key stakeholders to know that our Plan not only meets those regulatory mandates but that it is a "living document" that is being constantly revised and improved to go beyond those regulatory requirements. We will demonstrate that PSEG LI is focused on effective emergency management principles that not only enhance our ability to provide best in class reliability and storm response but enable us to do so in a safe and efficient manner, while providing timely and accurate information to our customers and stakeholders. Additionally, we will show that the Plan involves virtually every member of our organization, where in the event of an impending storm or other disaster, each employee knows his or her designated storm role and assignment – whether it involves actual restoration work, coordinating with responders or providing officials and customers with accurate, up-to-the-minute information. Finally, we will demonstrate that, through regular drills and exercises and "after action reports," the Plan is constantly refined and improved to offer the best service we can provide to our customers.

Q. Is the Panel sponsoring any exhibits in support of its testimony?

A. Yes, we are providing the ERP as an Exhibit ___ (SRP-1). The Plan is described in our testimony. We note further that LIPA reviewed and provided input for that Plan.

II. FACTORS AFFECTING STORM RESPONSE

Q. In your earlier description of your testimony you mentioned the Company's Mission Statement and objectives that focus on enhancing storm response.

A. Yes, we did. A first in class storm response program is one of our four core objectives along with safety, reliability, and customer satisfaction.

Q. Are there other indications of the emphasis that PSEG LI places on storm response?

A. Yes there are. For example the Amended and Restated Operations Services Agreement Between Long Island Lighting Company d/b/a LIPA and PSEG Long Island LLC, dated as of December 31, 2013 ("OSA"), contains metrics that PSEG LI must satisfy as part of its contractual commitments. Among the metrics that track how PSEG LI performs in responding to storms are (1) Storm CAIDI, which measures our performance during LIPA storm events as defined in the OSA, and (2) a default metric for failure to achieve 410 points on the DPS Scorecard for large scale events. Further, as another indication of the importance and attention we assign to storm response, the Emergency Preparedness organization now directly reports to Mr. John O'Connell, the Vice President of Transmission & Distribution, emphasizing the importance placed on this function, which in the past had been embedded further down in Operations. We will also describe in more detail, how additional resources have been added to the existing group in order to further strengthen our storm response efforts consistent with our goal to incorporate the best practices and lessons learned from Long Island, Public Service Electric and Gas Company ("PSE&G") in New Jersey, and the electric industry generally.

Q. Is PSEG LI subject to any regulatory or other requirements governing its response to storms?

A. Yes, there are several requirements. First, under the Public Service Law ("PSL"), the DPS is required to annually review our ERP for consistency with the Public Service Law and make recommendations to LIPA regarding its completeness in addition to our performance in restoring service during an emergency event.

The PSL also requires electric corporations subject to the jurisdiction of the Public Service Commission ("Commission") to make a filing, on or before December 15th of every year, of an emergency response plan for review and approval. Although LIPA is not subject to the Commission's review and approval, it is required under Section 3-b to make such a filing for DPS's review and recommendations to the LIPA Board.

Q. Did PSEG LI file its Plan with the DPS?

A. Yes, we did. The initial Plan was filed with the DPS in February 2014, with a revised filing provided in June 2014.

Q. Is that PSEG LI's most recent filing?

A. No. The DPS asked PSEG LI to make a filing as of December 15th to bring us into line with the timing for the filings made by the large, investor-owned utilities in New York which were required to make their filings on that date. PSEG LI agreed to make a new filing and that Plan is presented in Exhibit ___ (SRP-1). The consideration of that Plan by DPS and any recommendations it might make to the LIPA Board are being considered separate and apart from this Rate Plan filing.

Q. Are there other regulatory requirements in addition to PSL Section 66(21) that PSEG LI has taken into consideration in developing its Plan?

A. Yes. The Commission has promulgated regulations at 16 NYCRR Part 105 that also address and amplify the requirements in Section 66 of the PSL and PSEG LI's Plan takes those regulations into consideration.

III. MEASURING STORM RESPONSES

Q. Is there anything else that governs PSEG LI's planning for, and response to, storms?

A. Yes there is. The OSA provides a specific metric covering storm performance which is tied to the NYS Public Service Commission Storm Performance Scorecard. Although the Metrics Panel's testimony extensively discusses the OSA metrics, we will briefly discuss this provision. OSA Section 8.4 and Appendix 13 of the OSA provide a metric to measure PSEG LI's performance in storms. The metric provides, in relevant part, that:

> The Service Provider will be deemed to have failed the Major Storm Performance Metric under Section 8.4(C) of the Agreement if, commencing in the third Contract Year of the Term, the Service Provider, in the then-current Contract Year and any one of the preceding two (2) Contract Years, fails to achieve at least 410 points out of a maximum of 1000 points as calculated pursuant to the modified version, as agreed upon by LIPA and the Service Provider in the letter agreement dated as of the date of the Agreement, of the NYPSC Emergency Performance Measures issued on April 24, 2013 in "CASE 13-E-0140—Proceeding on Motion of the Commission to Consider Utility Emergency Performance Metrics."

Q. From where is the 1000 point system derived?

A. The explanation of the point system can be found in the Commission's "Order Approving The Scorecard For Use by The Commission as a Guidance Document to Assess Electric Utility Response to Significant Outages" which was issued in Case 13-E-0140 on December 23, 2013. The 1000 points that comprise the scorecard are divided into three categories:

1. Preparation 150 points
2. Operational Response 550 points
3. Communication 300 points
4. Maximum Available Points 1000

The full scorecard including the categories and descriptions and definitions were attached to the Commission's order in that case.

VI. KEY DRIVERS OF THE ERP

Q. You mentioned that PSEG LI filed a new ERP. What are some of the key drivers for changes made to the new Plan?

A. We filed a new plan because our ERP is constantly being reviewed and revised in order to meet the following:

- evolving customer expectations
- regulatory requirements
- alignment and coordination of activities with municipalities and governmental agencies
- advances in technology
- severity of recent storm events

Overall, the focus of such efforts is to improve the customer experience during storms and improve overall customer satisfaction with the service provided by PSEG LI.

Q. How has PSEG LI's Plan evolved to meet the factors you just described?

A. Our approach to enhancing the ERP involves continuous improvement that results from several processes. First we engage on a regular basis in Lessons Learned/After Action Reviews. These reviews permit us to ascertain what worked well, what did not go so well and what opportunities exist to improve. Second, we are in communication with PSE&G, and work to share the best practices learned between Long Island and New Jersey. Third, working through groups and study, we keep up to date on industry best practices, especially to see if a practice followed at one utility has relevance to our situation. Fourth, we play an active role in industry organizations such as the Edison Electric Institute ("EEI") and NAMAG. In fact, in many cases, PSEG LI employees play leadership roles on various industry committees that help to shape and drive discussion around emergency response efforts.

Q. Although you have submitted the entire Plan as an exhibit, would you please briefly describe the major aspects of PSEG LI's Plan?

A. Yes. In sum, the Plan represents a joint collaboration among all elements of the Company, including the T&D, Business Services and Customer Services Departments, to ensure that we are working together to restore the system to full operation as quickly and safely as possible while providing accurate and timely communications to our customers and to state and local officials, while coordinating responses to the event. Together these departments provide for the operations, communications and logistics aspects necessary for a comprehensive and well executed storm restoration effort.

Key elements include: (1) conducting effective business and operational risk assessments; (2) developing appropriate prevention and/or mitigation strategies; (3) developing and implementing comprehensive preparedness programs, processes and procedures; (4) making appropriate resources available for the emergency response; (5) communicating timely, accurate and relevant information to customers and stakeholders; (6) responding and recovering from events quickly; and, (7) assessing performance and continuously improving. An overarching element of the Plan is preparing all of our employees and resources to respond appropriately. This involves taking action to ensure the readiness of our personnel and making certain that all required support is available.

V. EMPLOYEES ROLES IN EMERGENCY RESPONSE

Q. Please describe how you prepare your employees and resources to respond.

A. A critical element of the ERP is making sure that all of our employees know where they need to be and that they know their assigned role. In fact, all of our employees are assigned a storm role upon hiring. Our focus is on executing a robust and comprehensive training, drill and exercise plan that prepares our employees for their storm roles. We conduct a combination of field, classroom and on-line sessions to ensure proper training is provided on a timely basis. One such example is our Annual Hurricane Tabletop Exercise which not only exercises our employees but includes participation of many key external stakeholder groups (e.g., DPS, OEMs, cable, telecommunications and gas providers, first responders).

Q. Are employees provided training with respect to these tasks?

A. Yes, they are. Each year a comprehensive training plan is developed to guide the delivery of the appropriate training to ensure the readiness of employees to effectively perform their assigned storm roles.

Q. Do you take steps to ensure that resources outside of PSEG LI can be drawn upon?

A. Yes, we do. On a regular basis, we discuss how to approach resource sharing with PSE&G to ensure that personnel can be transferred as needed between the two operations and that any required materials (e.g., transformers) can be moved to where the need is greatest. We also actively participate in activities with the NAMAG and meet periodically with other utilities, both regionally and nationwide, to ensure that our mutual aid protocols are up to date, workable and flexible.

VI. NEW PROGRAMS TO ENHANCE THE EMERGENCY RESPONSE

Q. You mentioned that PSEG LI's approach to storm response is constantly evolving. Can you provide some examples of the new programs or initiatives PSEG LI has introduced?

A. Yes, for example the new Outage Management System ("OMS"), which provides for enhanced damage assessment and data collection, is one such change. The OMS, together with other new processes, has improved storm response and outage restoration. The new OMS has replaced an older system and brings new features that enhance the restoration process. It uses technology to enable access to more real-time information on outages and work completed, and it provides for more timely status information for customers and increased crew efficiencies due to effective dispatch tools, including outage maps and job closure information.

Q. Are there other changes being made?

A. Yes, we are currently engaged in a pilot program to assess the use of tablet technology to collect data associated with damage assessment. This entails a transition from data collection forms to electronic data capture utilizing GIS and GPS coordinate technology. Ideally, this will provide more timely collection, reporting and communication of information to key stakeholder groups. In the future our efforts will examine expansion of tablets and/or use of smartphones and direct feed of data to OMS. Additionally, we plan to execute on opportunities to work with local municipalities and other utility service providers (i.e., teleco/cable providers) to openly share information across the GIS platform to enhance situational awareness and improve restoration response. The completion of the OMS in August 2014 was a prerequisite to any expanded use of this data collection and presentment methodology.

Q. Are there any other new initiatives being pursued?

A. Yes. We introduced a formalized Flood Protocol in 2014 and introduced an enhanced Municipal/Roadway Clearance Assistance process to further enhance our responses during storms.

VII. <u>ENHANCED COMMUNICATIONS</u>

Q. Has the Customer Services organization also instituted new practices?

A. Yes, they have initiated a new, enhanced Customer Services – Communications Organization Storm Restoration Plan ("Communications Plan").

Q. Please briefly describe that Communications Plan.

A. PSEG LI's enhanced storm Communications Plan was developed to meet the expectations of our customers and stakeholders during storm restoration efforts and to support the DPS's Storm Scorecard targets and achieve high scores on utility performance with respect to our ability to receive and disseminate information related to the impact of storm/outage and restoration activities. The ERP includes a comprehensive communications process with a commitment to improving access to timely and accurate information, using expanded tools to meet customer communication preferences.

Q. What are the major elements of the Communications Plan.

A. The OSA gives PSEG LI full responsibility for communicating important information before, during and after storms to public, media, and government officials. This was not the case under the old MSA. The OSA emphasizes the importance of communication with our stakeholders which PSEG LI is addressing with the Communications Plan that incorporates the following elements:

- press releases and briefings
- website with storm center
- YouTube storm preparation videos
- municipal conference calls
- assignment of municipal liaisons and use of an escalation tracker
- community outreach centers
- social media team
- e-mail blasts
- contact center with high volume call application
- large customer support

PSEG LI's Communications Plan is intended to ensure that our customers and key stakeholders receive the storm preparation and restoration information necessary to coordinate local emergency response and permit us and our customers to recover from an emergency safely, quickly and with minimal disruption. During an extended power outage, it is important that consistent and useful information be provided as widely as possible to overcome any local communication limitations related to the emergency (cellular or internet outages, for example). Our new protocols ensure that accurate and timely reports will be shared across a broad range of platforms to reach customers and the general public, human service agencies, the media, the DPS, the State Emergency Management Office and other state agencies, county and local governments, emergency response services, law enforcement agencies, and other public service or public safety authorities.

Q. Has Customer Services implemented any other new initiatives?

A. Yes one of the new elements of our emergency response is Scheduling and Interactive Voice Response ("IVR") Messaging. The Scheduling and IVR Messaging Team is responsible for assigning staff schedules to cover expected inbound calls. At times of high caller demand due to storms, the High Volume Call Application ("HVCA") Messaging will provide a recorded message providing callers with outage information that is updated every two hours during normal business hours and every six hours outside normal business hours and is conveyed via IVR and other systems. The message will contain, at a minimum: the geographic area(s) affected; the estimated number of customers affected; and the estimated time of restoration per operational guidelines.

Q. Have other enhancements been made to the Company's storm response efforts?

A. Yes, we also have an Emergency Response Escalation Tracker ("ERET"). This is an internal system that has been developed to capture, record, track and respond to escalated issues and priorities reported by municipalities through the municipal liaisons, the municipal hotline, or the large customer account teams. In addition, a web portal has been established to allow designated municipal staff members to input issues directly into the ERET. The ERET was created as a tool to provide clear and timely information to government officials during PSEG LI's response to a major storm or other electrical emergency. Information input to the tool will help PSEG LI prioritize work in an effective and expeditious manner.

Q. Are the elements you've mentioned all described with much greater particularity in the ERP?

A. Yes, they are and we would direct anyone interested in a particular element of our ERP to direct their attention to that detailed document. The ERP shows our commitment to continuous improvement and refining our response to storms and other natural and man-made disasters.

Q. Does this conclude the Panel's direct testimony at this time?

A. Yes, it does.

JUDGE PHILLIPS: The next affidavit would be from Staff.

MR. MAZZA: Thank you, Your Honor. I would like to submit by affidavit the testimony and exhibit of the Staff Delivery Service Adjustment Panel consisting of Patrick Piscitelli, Gina Critelli, Paul J. Darmetko, Jr., Laurie Cornelius, and Mark Tintera. The documents consist of prepared testimony consisting of 38 pages plus a title page and prepared exhibits including Exhibit SDSA-1 consisting of 56 pages plus a cover page and indexes originally pre-filed on May 14, 2015 (handing).

JUDGE PHILLIPS: On the basis of the affidavit for the Staff DSA and Storm Response Panel that has been marked for identification as Exhibit 115, that is 115, the testimony of that panel will be copied into the record as though given orally.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

In the Matter of a

THREE-YEAR RATE PROPOSAL FOR ELECTRIC RATES AND CHARGES
SUBMITTED BY THE LONG ISLAND POWER AUTHORITY AND
SERVICE PROVIDER, PSEG LONG ISLAND LLC.

Matter Number 15-00262

May 2015

Prepared Testimony of:
Staff Delivery Service Adjustment
and Storm Reserve Panel

Patrick Piscitelli
Principal Utility Financial
Analyst
Office of Accounting, Audits &
Finance

Gina Critelli
Chief, Utility Accounting, Audits
& Finance

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Utility Engineer 3
Office of Electric, Gas, & Water

Laurie Cornelius
Emergency Preparedness Analyst
Office of Electric, Gas, & Water

Mark Tintera
Utility Engineer 1
Office of Electric, Gas & Water

Matter 15-00262 Staff Delivery Service Adjustment and Storm Reserve Panel

Q. Please state your names, employer, and business addresses.

A. Patrick Piscitelli, Gina Critelli, Paul J. Darmetko, Jr., Laurie Cornelius, and Mark Tintera. We are employed by the New York State Department of Public Service, which we will refer as the Department, or DPS. Mr. Piscitelli, Mr. Darmetko and Ms. Cornelius are located at Three Empire State Plaza, Albany, New York 12223, and Ms. Critelli and Mr. Tintera are located at 125 East Bethpage Road, Plainview, New York 11803.

Q. Mr. Piscitelli, what is your position at the Department?

A. I am employed as a Principal Utility Financial Analyst in the Office of Accounting, Audits, and Finance.

Q. Please provide a summary of your educational and professional experience.

A. A description of my educational and professional experience is contained in the testimony of staff’s Finance and Public Power Panel, of which I am a member.

Q. Have you previously testified in utility rate proceedings?

A. Yes, I have testified in numerous ratemakings proceeding before the New York State Public Service Commission regarding financial, accounting, utility expenditure prudence, and other ratemaking issues.

Q. Ms. Critelli, by whom are you employed and what is your business address?

A. I am employed by the New York State Department of Public Service, referred to as the Department or DPS, 125 East Bethpage Road, Plainview, NY 11803.

Q. Ms. Critelli, what is your position in the Department?

A. I am employed as Chief, Utility Accounting & Finance in the Office of Accounting, Audits, and Finance.

Q. Please describe your educational background and professional experience.

A. A description of my educational and professional experience is contained in the testimony of Staff's Policy, Overview, and Revenue Requirement Panel, of which I am a member.

Q. Have you previously testified in any utility rate proceedings or other ratemaking proceedings?

A. No.

Q. Mr. Darmetko, what is your position at the Department?

A. I am employed as a Utility Engineer 3 in the Electric Rates and Tariff Section of the Office of Electric, Gas, and Water.

Q. Please provide a summary of your educational and professional experience.

A. I graduated from the State University of New York Institute of Technology at Utica/Rome with a Bachelor of Science Degree in Civil Engineering Technology in 2003. I have been employed the Department since October 2005 in the Office of Electric, Gas, and Water, mainly in the Electric Rates and Tariff Section. While with the Department I have analyzed, reviewed, and prepared reports and studies involving operating revenues, operation and maintenance expense, capital budgets, depreciation, cost of service, revenue allocation, rate design, and sales forecasts.

Q. Mr. Darmetko, please describe your

responsibilities with the Department.

A. My current responsibilities include, providing engineering analysis and recommendations in rate proceedings, reviewing and making recommendations to the Commission on filed petitions, and examining utility processes and operations to ensure compliance with the Public Service Law and the policies of the Department.

Q. Have you previously testified in utility rate proceedings?

A. Yes, I have testified in Cases 05-E-1222, 08-E-0539, 08-G-0609, 09-E-0715, 09-E-0717, 10-E-0362, 10-E-0050, and 14-E-0318 regarding cost of service, capital budgets, rate base, depreciation, rate design, and other revenue requirement issues. All of these proceedings were before the New York State Public Service Commission.

Q. Ms. Cornelius, what is your position at the Department?

A. I am an Emergency Preparedness Analyst in the Office of Electric, Gas and Water.

Q. Please provide a summary of your educational and professional experience.

A. I graduated from the University at Albany in 2010 with a Bachelor of Arts degree in History. I have been employed by the Department of Public Service since 2004 where I have held positions of increasing responsibility and currently work in the Electric Distribution Systems section.

Q. Ms. Cornelius, please describe your responsibilities with the Department.

A. My current responsibilities include reviewing Emergency Response Plans, assisting in emergency response activities, reviewing annual capital and operations expenditures and maintenance programs, monitoring storm hardening efforts, and monitoring PSEG Long Island LLC, or PSEG LI's, and the Long Island Power Authority, or LIPA's compliance with the LIPA Reform Act, New York State Public Service Law and New York Codes, Rules and Regulations.

Q. Have you previously testified in utility rate proceedings?

A. Yes, I have testified in Case 10-E-0050, National Grid, d/b/a Niagara Mohawk Power Corporation rate proceeding before the New York State Public Service Commission.

Q. Mr. Tintera, what is your position at the Department?

A. I am employed as a Utility Engineer I in the Office of Electric, Gas and Water.

Q. Please provide a summary of your educational and professional experience.

A. I graduated from the State University of New York at Farmingdale in 2008 with a Bachelor of Science degree in Mechanical Engineering Technology. I have been employed by the Department since 2014. Prior to joining the Department, my professional experience included 9 years at two Mechanical Engineering and Design firms and two local government positions. I worked for six years designing drive components at Designatronics Inc., one year designing mechanical systems at Genesys Engineering, and a total of two years at the Town of Huntington as a Building Permit Examiner, and Suffolk County as a Public Health Sanitarian.

Q. Briefly describe your responsibilities with the Department.

A. My responsibilities include reviewing PSEG LI's transmission and distribution capital improvements and emergency response plans for conformance with New York State and industry-wide best practices.

Q. Have you previously testified in utility rate proceedings?

A. No.

Q. What is the purpose of the Panel's testimony?

A. The purpose of our testimony is to: i) provide our recommendations regarding the Delivery Service Adjustment, referred to as the DSA, that has been proposed in this filing by witnesses of LIPA and PSEG LI, and, and ii) provide a summary of our review of the proposed storm reserve account and our recommendation regarding the treatment of storm reserve levels. We will provide a summary of our understanding of the proposed DSA mechanism, describe the various components of the DSA mechanism, and finally describe our recommended changes regarding the operation of the storm reserve. The changes we are recommending will allow LIPA to utilize the excess storm reserve balance to offset other DSA cost components, or to pay down debt if the balance grows beyond acceptable levels. We also recommend the establishment of a process for the DPS to review and if needed, provide recommendations to the LIPA Board of Trustees prior to the DSA becoming effective each year.

Q. In your testimony, will you refer to, or otherwise rely upon, any information obtained during the discovery phase of this proceeding?

A. Yes. We relied on several responses provided by LIPA and PSEG LI. These are attached as Exhibit___(SDSA-1).

Q. Please generally describe the DSA mechanism?

A. The DSA mechanism is a cost true-up instrument that will annually reconcile certain costs included in LIPA's base delivery rates to actual costs incurred by LIPA. The DSA, as proposed, has three cost true-up categories:

i) Debt service costs

ii) Power Supply costs, and

iii) Storm costs.

Q. Could you please generally describe why LIPA and PSEG LI have proposed to establish the DSA mechanism in this case and describe the intended outcome?

A. LIPA witness Thomas Falcone discusses in detail the reasons why the mechanism is being proposed. In summary, the primary goal of the proposed DSA mechanism is to reduce the risk profile of the LIPA and allow it to achieve a higher credit rating at the recommended revenue levels. This should reduce the long term costs for its customers through lower costs of debt. The use of the DSA ensures current recovery of the actual costs within the three cost categories which gives greater certainty to bondholders and banks that the costs will be recovered. This allows LIPA to achieve comparable bond ratings with lower financial metrics than would be required without the DSA and will reduce the rate increases necessary over the years of the rate plan. Another reason cited for the establishment of the DSA is that there are several cost savings possibilities that will be returned to customers through the DSA in the event that favorable outcomes are achieved. For example, a more favorable, property tax settlement between taxing jurisdictions and LIPA, and the potential for lower cost refinancing available from the UDSA refunding of

LIPA's bonds than is being forecasted.

Q. Does the Panel agree that the establishment of the DSA mechanism should increase the credit rating of LIPA, and thereby reduce costs to its customers over time?

A. Yes. The DSA will reduce investment volatility and should translate into lower debt costs for customers. This should occur since the DSA will provide assurance that LIPA will meet its debt service payments by truing up actual costs with the costs included in approved rates. The resulting lower volatility will translate into lower investment risk and should result in lower debt service costs.

Debt Service Costs

Q. Please describe LIPA and PSEG LI's proposal to recover the variation in debt service costs through the DSA.

A. LIPA and PSEG LI have proposed to recover, or pass back to customers, the variation in interest rates, issuance amounts, and the debt service coverage requirements through the DSA. LIPA and PSEG LI propose to include the yearly variation in debt service related costs in the year following their occurrence.

Q. Why may debt service related costs vary from those allowed in rates?

A. Debt service costs may vary from those allowed in rates for three reasons. First, the interest rate of newly issued debt has been estimated based upon existing market conditions and maturity schedules. The actual market interest rates and maturity schedules may differ from those approved in rates. Second, the cost of a portion of LIPA's various outstanding debt instruments fluctuate throughout the rate period based upon existing market conditions. Finally, the actual amount of debt issued may vary from the forecast.

Q. Are true-ups of interest rates, debt coverage requirements, and issuance amounts typically allowed for other New York State utilities?

A. In certain rate proceedings, recovery for variations in interest rates for variable rate securities has been allowed. However, typically true ups for issuance amounts, interest rates for newly issued debt, or debt service coverage requirements are not allowed. We believe that the reduction of customer costs outweighs the uniqueness of the DSA mechanism.

Q. Why is LIPA requesting that the DSA allow recovery for all debt service costs?

A. As stated in the testimony of the Ratemaking and Revenue Requirements Panel on page 26, line 11 through page 27, line 2, LIPA is requesting the true up for two reasons. First, it states that the size and maturity of issuances cannot be forecasted precisely. Second, LIPA also believes that the use of the public power model necessitates the recovery of all debt service related costs.

Q. Does the use of the public power model necessitate the inclusion of the debt service costs true up being requested?

A. No, it does not. The use of the public power model does not require the debt service true up mechanism. That is, the public power model can be implemented with, or without, the debt cost true up mechanism.

Q. Do you agree that the DSA should allow recovery of the debt service cost components as requested by LIPA?

A. Yes. We believe that the financial structure of LIPA is sufficiently different than that of investor owned utilities, or IOUs, and justifies a true up for all the requested debt cost elements being requested.

Q. How does LIPA's financial structure impact your recommendation to include the debt costs being requested in the DSA?

A. As detailed in the Staff Finance and Public Power Panel testimony, IOUs are generally financed with a combination of debt and common equity. Within parameters, the risk associated with the variation of IOUs' non-variable rate debt costs are borne by equity investors. Since LIPA does not have equity investors, potential variations in debt related costs will be borne by debt holders. These variations can have a significant impact upon LIPA's cost of borrowing.

Q. Have you considered LIPA's overall financial condition in formulating your recommendation?

A. Yes. LIPA's relatively weak financial condition does not allow for significant variation in debt service costs before its financial condition would be negatively impacted. As discussed in the testimony of the Staff Finance and Public Power Panel, LIPA's financial metrics are among the lowest in the industry with projected debt coverage ratios between 1.20 and 1.40. The debt coverage ratio represents the ratio of cash available for debt service to the actual interest, principle, and lease payments. This compares to the expected A rated IOU debt coverage ratio of between 4.5 and 6.0.

Q. Why should the debt service coverage requirements also be included in the DSA?

A. Including the debt service coverage requirements in the DSA allows the debt interest coverage to be unaffected by potential changes in interest costs. As discussed in the testimony of the Staff Finance and Public Power Panel, LIPA's financial metrics are below its industry peers. Without including debt service coverage protection in the DSA, the already weak debt service coverage metrics may deteriorate even further.

Q. What is the impact upon future rates if revenues are increased to sustain the debt service coverages?

A. There are two potential benefits to customers. First, providing debt service coverage protection reduces risks and should lower LIPA’s future debt service costs. Second, the additional revenues will offset LIPA’s future financing requirements. Both benefits will serve to lower LIPA’s future revenue requirements.

Power Supply Costs

Q. Could you please describe the Power Supply costs included in the DSA mechanism?

A. The power supply costs that are proposed to be included in the DSA mechanism are: 1) the costs incurred under the Power Supply Agreement, or PSA, between National Grid Generation LLC, referred to as National Grid, and LIPA, and 2) Operation and Maintenance expenses associated with LIPA’s share of the Nine Mile Point II, referred to as NM2. These costs are shown in the PSEG LI Ratemaking and Revenue Requirement Panel, Exhibit RRP-1 on Schedule A-4, next to the headings “National Grid Power Supply Agreement” and “Nine Mile Point 2 O&M”.

Q. Does the Panel agree that these costs should be included in the DSA mechanism?

A. Yes. The PSA contract costs can generally be described as capacity costs that the LIPA pays to National Grid to satisfy a significant portion of LIPA’s On-Island capacity requirements. All other electric utilities in New York State flow through capacity costs to customers monthly, based on actual costs. Therefore, allowing LIPA to reconcile these costs is consistent with Departmental policy to allow for full recovery of power supply related costs. One could argue that these costs could or should flow through LIPA’s Fuel and Purchase Power Cost Adjustment charge monthly instead of being included in base delivery rates, however, because of the impact this would have on Long Island Choice program participating Energy Service Companies, we recommend that the topic of removing the PSA cost from base delivery rates be included in a separate proceeding. The PSEG LI Power Supply Panel, as well as PSEG LI witness Joseph Trainor, have proposed that a separate proceeding be established to investigate steps to improve the Long Island Choice program. We believe the topic of potentially removing the PSA from base rates should be examined in that proceeding. We also recommend that the separate proceeding be initiated no later than the conclusion of the existing rate case filing. In the meantime, it is reasonable to recover the differences in budgeted and actual costs of the PSA on an annual basis through the DSA mechanism.

Q. Moving on to the O&M costs associated with LIPA's share of NM2, do any utilities in New York State recover retained generation cost through base delivery rates and reconcile them?

A. Yes, Consolidated Edison Company of New York, Inc. includes the costs of its own generation in base delivery rates and reconciles differences in O&M expenses from rate plan allowances through its Monthly Adjustment Clause.

Q. Does the Panel agree that these costs should be included in the DSA mechanism?

A. Yes. These costs are difficult for LIPA to predict and have historically varied by as much as 10 percent from projections. This degree of uncertainty, especially because of the multi-year rate setting in this proceeding, will appear unfavorable to rating agencies if left un-reconciled. For this reason, we recommend these costs be included in the DSA.

Storm Reserve

Q. Has LIPA and PSEG LI proposed establishing a storm reserve as part of the DSA?

A. Yes. LIPA and PSEG LI propose to create a storm reserve to cover major storm costs funded through base rates over each of the three rate years. The storm reserve would be used to reconcile the amounts included in base delivery rates and the actual amount of storm costs incurred by LIPA.

Q. How does the DPS view storm reserves?

A. Storm reserve accounts are supported by the Department. The potential for a utility to incur substantial costs in the circumstances of severe weather provide proper justification for the use of reserve accounting to cover the costs that cannot be adequately forecast in advance and must be incurred for service reliability and continuity. Storm reserve accounts collect a fixed amount through base rates as established in rate plans, to cover major storm costs. The reserve can have a debit balance, or be underfunded, or a credit balance, and hence be overfunded, depending on actual storm activity. Funds collected in base rates are credited to the reserve when received and storm costs are debited to the reserve account as incurred.

Q. What are the benefits of storm reserves?

A. There are several positive outcomes of having a storm reserve. They include: greater company focus on repairs, reliability, and restoration; more stable and predictable rates for customers; more stable and predictable funding for costs for utilities; excess money collected is held as a regulatory liability for future storm events; and, the lowering of the risk profile of the utility. A storm reserve account provides more stable and predictable rates for ratepayers and more stable and predictable funding of costs incurred by PSEG LI. Lastly, it calls for the costs charged to the reserve to be periodically reviewed to ensure they are appropriate.

Q. Please explain generally how PSEG LI currently recovers its expenses related to major storms.

A. Currently, the Operations Services Agreement, or OSA, allows storm costs to be recovered in base rates. LIPA and PSEG LI have proposed following the specific criteria in the OSA that must be met on a per storm event basis, to determine which storm costs would qualify as chargeable to the storm reserve.

Q. Does a storm reserve currently exist?

A. Yes. Section 5.3(B) of the OSA details the obligation of LIPA to fund a storm reserve account in the amount of $15 million, and also sets forth the mechanism for replenishing the storm reserve should the balance fall below $3 million due to withdrawals by PSEG LI. The OSA allows PSEG LI to withdraw funds from the storm reserve which is not part of its budget for storm events, not limited to "major storm" costs, to pay for costs it incurs in connection with a storm event. Section 5.3(B) also provides the opportunity for PSEG LI to request that LIPA replenish or temporarily fund the Storm Reserve in an amount exceeding $15 million if PSEG LI anticipates that storm costs may exceed the available balance in the Storm Reserve.

Q. Does the $15 million storm reserve required by the OSA impact the storm reserve proposed by LIPA and PSEG LI?

A. No. The existing storm reserve serves as a vehicle for PSEG LI to readily access funds to pay for costs incurred in anticipation of a storm event. Once the storm meets the OSA storm event criteria, a work order number is assigned by LIPA and all storm event costs for that event are then charged directly to the event's work order number for tracking and billing purposes. It is our understanding that maintaining the $15 million storm reserve balance is a contractual obligation of LIPA under the OSA and is separate from the proposed storm reserve in this proceeding.

Reserve Accounting for Storm Event Costs

Q. Does the definition of a storm event used by LIPA and PSEG LI differ from the definition of a major storm used by DPS?

A. Yes. The DPS uses the definition of a major storm found in 16 NYCRR Part 97 characterized as "a period of adverse weather during which service interruptions affect at least ten percent of a utility's customers within an operating area and/or results in customers being without electric service for the duration of at least twenty-four hours." PSEG LI and LIPA, however, do not use the term "major storm," but rather follow the definition of a "Storm Event" defined in the OSA as an event where at least 15,400 customers are interrupted or at least 150 jobs are logged in each case within a 24 hour period.

Q. Is LIPA and PSEG LI's criteria for qualifying storm events acceptable?

A. Yes. Although it is different than the DPS definition of a major storm, LIPA and PSEG LI are bound by the definition of a storm event under the terms of the OSA. Additionally, the OSA provides specific language detailing allowable and disallowable costs. Appendix 10 of the OSA lists chargeable cost codes which PSEG LI must use when billing LIPA for storm event costs.

Q. What specific costs are considered chargeable to the storm reserve?

A. Chargeable costs specified in the OSA include, but are not limited to, straight time labor, non-capitalized costs, etc., which the Panel believes to be reasonable.

Q. Does the Panel have concerns with the treatment of chargeable costs by LIPA and PSEG LI?

A. Yes. We are concerned with the treatment of straight time labor costs and the manner in which storm event costs are reconciled with respect to straight time, as well as how PSEG LI and LIPA are tracking actual storm event costs charged to and paid by LIPA.

Q. Please explain these concerns.

A. During our review of the testimony and DPS-KK-354, LIPA and PSEG LI failed to distinguish whether they made adjustments for straight time labor costs that are already being recovered in base rates.

Q. Does the Panel recommend any modifications regarding the proposal regarding this concern?

A. Yes. We recommend that only incremental costs be charged to the storm reserve account. Costs that should not be charged to the storm reserve include all capitalized costs and proceeds or reimbursements from insurance, FEMA, New York State or any other reimbursement or proceeds received by third parties to cover such costs. We are also recommending that LIPA and PSEG LI modify the manner in which storm event costs are tracked and reported going forward. In the case of straight time labor, we recommend that PSEG LI file a report with DPS within 30 days after a storm event where costs were charged to the storm reserve. This report should reconcile labor costs recovered in base rates to the labor costs charged to the storm reserve. This will preclude double counting. In the case of tracking actual storm event costs i.e., amounts billed to LIPA, and the time it takes to pay those costs in full, we recommend that PSEG LI file with DPS an annual report beginning on January 1, 2016 detailing by storm event the actual costs incurred to date, the amount billed to LIPA with an explanation for any variance between the two figures, and the amount paid by LIPA to PSEG LI to date with an explanation why any outstanding billed amount has not been paid.

Q. Have you taken into consideration costs that PSEG LI may incur in anticipation of a storm event that does not materialize?

A. Yes. Over the past few years, qualifying storm events have occurred more frequently and thus recovery has become increasingly more costly. Under the terms of the OSA, PSEG LI has been given the sole responsibility for emergency preparedness and full decision making authority to prepare for and respond to predicted storm events. To that end, PSEG LI must balance forecasted weather with its experience in responding to events that correspond with the anticipated impact of predicted weather. As with PSEG LI, we have seen other New York utilities make informed decisions in advance of an event concerning storm support resources, including securing mutual assistance. New York utilities have moved towards an increased time period in which they prepare for a storm, often by as much as four days in advance of a storm event. With these anticipatory actions, there is the potential for costs to be incurred for events that do not fully materialize or when actual weather is less severe than predicted. These unrealized events do not meet the criteria under the OSA definition of a storm event, and therefore, the associated costs would not normally be charged to a storm reserve.

Q Does the Panel have any recommendation for DPS review in these instances?

A. Yes. Currently, under the LIPA Reform Act DPS is obligated to monitor PSEG LI's emergency preparedness and storm response. In fulfilling this obligation, DPS reviews PSEG LI's performance both prior to, during and after a storm event. Going forward, to the extent necessary, DPS will examine all preparatory storm costs incurred by PSEG LI for events that do not materialize. Following this examination, DPS may, if necessary, make formal recommendations to the LIPA Board of Trustees as to the reasonableness of those costs prior to authorization for payment given by the LIPA Board.

Q. Please continue.

A. As part of the DPS review and analysis of such preparatory costs, the Panel recommends that when asked by DPS to do so, PSEG LI file a report with DPS that includes, but is not limited to, a full accounting of all storm event costs and the total amounts billed to LIPA that will be charged to the storm reserve. The report should justify that there was reasonable anticipation that the forecasted event would have been consistent with the definition of a storm event as defined in the OSA had it materialized.

Storm Reserve Funding Level

Q. Please explain how LIPA calculated the reserve account allowance that is recommended to be included in base delivery rates.

A. In response to DPS-SRP-0197, LIPA identified all storm events with their total associated cost for the four year period ending December 31, 2014. LIPA then summed each year’s storm event expenses, after appropriately excluding four extraordinary storms the costs of which LIPA indicated were reimbursed by FEMA. LIPA then calculated a four year average of $53,248,082.17 and applied a 5.7%-9.5% annual inflation adjusted reduction based on a strengthened and storm hardened system for a 2015-2018 projected storm budget of $48,597,000, $48,169,000, $49,077,000, and $50,199,000, respectively.

Q. According to the data provided, do all the storms identified in DPS-SRP-0197 meet the definition of a storm event as defined by the OSA?

A. Yes, all of the qualifying storms listed in DPS-SRP-0197 were shown in DPS-KK-354 to meet the criteria of a storm event as defined in the OSA.

Q. Based on your review, does the Panel believe the most recent four year period of storm event activity is a reasonable amount of time to determine average storm event levels?

A. Ideally, a longer period of time, typically 10 years, is used to calculate an average major storm level. In this instance 10 years was not used because of a storm cost accounting methodology change made by the previous service provider, National Grid, in 2006. According to PSEG LI's response to DPS-CBP-0290, prior to 2006, LIPA's T&D budget for operations included $4.2 million for storm costs under the terms of the Management Service Agreement, or MSA, between LIPA and National Grid. With respect to in-house labor, prior to 2006, National Grid only billed LIPA for overtime for qualifying storm events as defined in the MSA. Beginning in 2006, however, the $4.2 million was excluded from the operating budget and all related storm costs, straight time, overtime, payroll burdens and fringe benefits were thereafter billed to LIPA *in toto*.

Q. Did Staff do any calculations as part of its analysis to determine the reasonableness of LIPA and PSEG's storm cost averages used to establish the storm reserve collections for 2016, 2017, and 2018?

A. Yes. Staff prepared calculations using the previous service provider's historical storm data back to 2006 provided in DPS-CBP-0290. Using the longer period produced only negligible differences to the four year storm average provided by LIPA and PSEG LI. Therefore, Staff believes that in this case departure from the ten year historical period generally used in other rate proceedings is reasonable. Staff supports LIPA and PSEG LI's 2015 through 2018 projected storm reserve collections of $48,597,000, $48,169,000, $49,077,000, and $50,199,000, respectively, and is making no recommendation for any changes to these amounts.

Q. Staff mentioned earlier its testimony that LIPA and PSEG LI used an annual inflation adjusted reduction each year in the calculation of the annual storm reserve collections. Do you agree with PSEG LI’s 5.7%-9.5% annual inflation adjusted reduction based off of a strengthened and storm hardened system?

A. We believe that it is reasonable to add an annual inflation adjusted reduction to the storm event averages based on a storm hardened system. However, we cannot support or refute the numbers provided PSEG LI because no supporting documentation was provided as requested in DPS-SRP-197.

Q. Does Staff have any recommendation regarding future calculations of storm reserve collections?

A. Yes. Going forward, Staff recommends that a longer time period be used to calculate the storm event average as more data becomes available. Staff recommends that once 10 years of data is available that 10 years of data become the measure to calculate storm event averages in further rate filings.

Q. Does the Panel agree that major storm costs recovered through base rates should be included in the DSA mechanism?

A. Yes. Major storm costs are very difficult to estimate accurately and differ significantly from year to year. Including them in the DSA mechanism will provide rating agencies greater assurance that the actual costs of storms will be recovered over a reasonable period, which should reduce customer costs over time.

Q. What will happen if the annual storm reserve collections proposed by LIPA and PSEG LI prove to be either too high or too low?

A. The DSA mechanism will reconcile the differences in a subsequent rate year as described later in this testimony.

Operation of the DSA

Q. Does the Panel agree with the proposed operation of the DSA mechanism, as discussed in the direct testimony of PSEG LI witness Joseph Trainor?

A. Yes, but with a modification to the operation of the storm reserve component of the DSA.

Q. Please explain how the DSA mechanism will operate and discuss your proposed modification?

A. Each year LIPA will compare the actual costs it incurs in each tracking period to the levels used to establish base delivery rates in this proceeding for each of the three cost categories. The sum of the differences of the three DSA components will be translated to a LIPA wide percentage, based on forecast applicable delivery revenues. This DSA factor will be multiplied by applicable customers' delivery charges each month of the true-up period, which will reset each January 1. The DSA charge or credit will be recovered or passed back to customers on a separate line on customers' bills. Any over or under collection or crediting of the DSA will be tracked and reconciled in a subsequent recovery period through next year's DSA charge or credit. The first tracking period will commence with the beginning of the first year of the rate plan, January 1, 2016 and end September 30, 2016. All subsequent tracking periods will begin October 1 and end on September 30. Each year, a new DSA charge or credit will go into effect on January 1.

Q. Will all components of the DSA be calculated using the same methodology?

A. No. The Power Supply and Debt Service Cost components of the DSA will be calculated in the same manner. The difference in the amounts actually expended by LIPA in each tracking period will be compared to the amount reflected in base delivery rates. The differences will be divided by the forecast applicable delivery revenues in the following calendar year, or "reconciliation year", to establish these two components of the DSA recovery charge or credit. Differences in Storm Cost will be treated somewhat differently, with three possible scenarios: 1) in the event actual costs expended on Storms are less than the amount included in rates, the excess recovery will be retained in the reserve account for future offset of storm costs; 2) if actual expenses are more than the amount included in rates, but less than the amount include in rates plus the current balance in the reserve account, the reserve account will be drawn upon to meet the expense; 3) finally, if the actual expense is greater than the amount included in rates plus the current balance in the reserve account, one third of the shortfall will be included in the calculation of the DSA Storm component. This shortfall will be divided by the applicable delivery revenues in the same manner as the Debt Service and Power Supply components.

Q. Why are Storm Costs being treated differently?

A. In Mr. Trainor's testimony, he explains that Storm Costs can vary significantly from year to year, and by spreading high cost years that exceed the base rate allowance and the reserve balance over a three year period, there is a good chance that a low cost year will offset a high cost year, thus smoothing the impacts.

Q. Does the Panel agree with the operation of the DSA's Storm cost component?

A. Yes, but we recommend a modification to the operation of the storm reserve.

Q. Please describe the proposed modification?

A. We recommend that a cap and ratchet mechanism be established for the storm reserve. We recommend that the maximum amount the reserve can build be capped at no more than 1.5 times the expense amount included in base delivery rates each year. As discussed above, we support a base rate allowance of $48.2 million in 2016, $49.1 million in 2017, and $50.2 million in 2018, be included for storm expense. Therefore, we recommend a reserve cap of $73.65 million in 2017, and $75.3 million in 2018. We have intentionally excluded a cap in 2016 because it is not possible for the cap to be triggered in that year. In the event either of these caps are triggered, we recommend the reserve balance be reset to the base rate allowance level in that rate year and that the difference between rate year allowance and the cap be utilized by LIPA to pay down LIPA's debt, or offset other DSA cost components in the tracking period that the caps are reached. Once the reserve balance is reset to the base rate allowance level, it would resume building back up to the cap. If the balance again reaches the cap, the process would repeat.

Q. Why is the Panel proposing a cap and ratchet?

A. We recommend the cap and ratchet be utilized to prevent the possible excessive buildup of customers’ money in the storm reserve. We believe that reserve amounts above the base rate allowance each year should be utilized to the benefit of customers as soon as possible, but do not wish to undermine the rational for establishing a storm reserve.

Q. How did you arrive at the cap of 1.5 times the base rate allowance?

A. From our review of the historic spending on storms, we observed that since 2006, the highest single year storm expenses that would have been charged to the storm reserve was approximately $75 million, which is approximately 1.5 times the rate allowance for storm costs that we are recommending in this testimony. We recommend that the highest storm year be used as the basis for the cap, or trigger for the ratchet. We believe that the proposed cap of 1.5 times the base rate allowance each year gives LIPA a reasonable mechanism to mitigate storm costs in excess of a “normal” year and that in the unlikely event that a cap is reached, ratcheting back the reserve balance to the rate year allowance level will provide a reasonable storm reserve balance in the event the reserve is needed to pay for storm costs in excess of the annual rate base allowance.

Q. Do you have any other recommendations regarding the DSA mechanism?

A. Yes. We recommend an annual filing be submitted to DPS Staff for review and comment. The filing should be submitted to the DPS no more than 30 days following the conclusion of each tracking period. DPS Staff will review the calculation of the DSA charge or credit prior to the January 1st effective date. In the event DPS Staff finds it necessary to recommend changes or finds errors in the calculation, Department Staff will report their findings and recommendations to LIPA’s Board of Trustees for its consideration one week prior to the annual December meeting of the LIPA Board.

Summary of Recommendations

Q. Please summarize your testimony and

recommendations?

A. We agree with the LIPA and PSEG LI that the establishment of the DSA mechanism will benefit customers in both the short and long run. However, we recommend that certain customer protections be established such as limiting the amount of storm costs that can be retained by LIPA in the Storm reserve account. We also recommend a formal DPS review process be established, prior to the annual change in the DSA charge or credit. With these changes we recommend the DSA be implemented by LIPA so that customers will benefit from lower future debt costs through lower borrowing rates.

Q. Does this conclude the Panel’s testimony at this time?

A. Yes, it does.

JUDGE PHILLIPS: I believe the next panel is Staff Policy Overview and Revenue Requirement Panel.

MR. MAZZA: Yes. Thank you, Your Honor. I would like to enter into the record by affidavit Staff Policy Overview Revenue Requirement Panel consisting of Gina Critelli, Michael Twergo and Christian Bonvin.

The documents consist of prepared revised testimony which consists of 44 pages plus a title page and prepared revised exhibits including Exhibit PORR-1 consisting of three pages, Exhibit PORR-2 consisting of one page, Exhibit PORR-3 consisting of one page, Exhibit PORR-4 consisting of one page, Exhibit PORR-5 consisting of one page, Exhibit PORR-6 consisting of five pages plus a cover page and indexes submitted on June 8, 2015 (handing).

JUDGE PHILLIPS: On the basis of the affidavit just described and marked for identification as Exhibit 116, the Revised Testimony of the Staff Policy Overview and Revenue Requirement Panel should be copied into the record as though given orally today.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

In the Matter of a

THREE YEAR RATE PROPOSAL FOR ELECTRIC RATES AND CHARGES SUBMITTED BY THE LONG ISLAND POWER AUTHORITY AND SERVICE PROVIDER, PSEG LONG ISLAND LLC

Matter Number 15-00262

June 2015

Prepared Revised Testimony of:
Staff Policy, Overview and
Revenue Requirement Panel

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Introduction and Qualifications

Q. Please state the names of the members of the Policy, Overview and Revenue Requirement Panel.

A. The panel is comprised of Gina Critelli, Michael Twergo, and Christian Bonvin.

Q. Ms. Critelli, by whom are you employed and what is your business address?

A. I am employed by the New York State Department of Public Service, referred to as the Department or DPS, 125 East Bethpage Road, Plainview, NY 11803.

Q. Ms. Critelli, what is your position in the Department?

A. I am employed as Chief, Utility Accounting & Finance in the Office of Accounting, Audits, and Finance.

Q. Please describe your educational background and professional experience.

A. I graduated from Adelphi University in 1989 and have a Bachelor’s degree in Accounting. I also received a Master’s degree in Business Administration with a specialization in Enterprise Resource Planning Systems from the University of Scranton in 2012. I am a

Certified Public Accountant and a Certified Internal Auditor in the State of New York. I have been employed by the Department since May 2014. Prior to joining the Department, I worked in various financial and accounting positions in Fixed Assets, Internal Audit, Payroll, and Finance Operations within National Grid and its predecessor companies for the past 22 years.

Q. Please describe your responsibilities with the Department.

A. My responsibilities include examination of accounts, records, documentation, policies and procedures for the Long Island Power Authority or LIPA and its service provider, PSEG Long Island LLC., or PSEG LI, and the development from that information of various analyses and recommendations. I am currently managing the Department’s review of the PSEG LI rate proceeding. I am also responsible for reviewing PSEG LI’s performance in relation to the metrics outlined in the Amended and Restated Operations Service Agreement, or OSA, between LIPA and PSEG LI, in accordance with the Department’s responsibilities pursuant to the LIPA Reform

Act, or LRA.

Q. Have you previously testified in any utility rate proceedings or other ratemaking proceedings?

A. No.

Q. Mr. Twergo, what is your position in the Department?

A. I am employed as the Chief of the Electric Rates & Tariffs Section in the Office of Electric, Gas and Water.

Q. Please summarize your educational background and professional experience.

A. In December 1981, I graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Electrical Engineering. Since joining the Department of Public Service in April 1982, I have held progressive engineering positions within the Office of Electric, Gas and Water and its predecessors. In February 2012, I was promoted to Chief of the Tariffs, Electric Supply and Small Utility Rates Section, and in October 2013, I was appointed to my current position. My responsibilities include the management and supervision of the Electric Rates

& Tariffs Section, which is comprised of eighteen engineers and analysts. The Electric Rates & Tariffs Section responsibilities include the analysis of electric rate case submittals; analysis of petitions related to changes in rates, charges, rules and regulations, sale of utility property, franchise extensions and waiver of rules; providing advice on local, state and federal policies and legislative proposals; review of major utility electric supply portfolios; responding to complex rate-related inquiries; oversight of utility implementation of New York Power Authority and certain other statewide economic development programs; implementation of net metering programs and tariffs; and processing of all electric, gas, water and steam tariff filings.

Q.   Have you previously testified in any utility rate proceedings or other proceedings?

A.   Yes, I have testified in numerous proceedings before the New York State Public Service Commission.

Q.   Mr. Bonvin, by whom are you employed?

A.   I am employed by the New York State Department of Public Service. My business address is Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Bonvin, what is your position in the Department?

A. I am employed as a Utility Supervisor in the Office of Electric, Gas, and Water.

Q. Please summarize your educational background and professional experience.

A. I graduated from the Worcester Polytechnic Institute in 1992 with a Bachelor of Engineering Degrees in Mechanical Engineering and Civil Engineering. I accepted employment with the Department of Public Service in August 1993 and currently work in the Department's Electric Distribution Systems section. My duties include the technical analysis of capital projects, reviewing operations and maintenance programs, and monitoring the provision of safe and reliable service. I am also responsible for emergency planning and response.

Q. Have you previously testified in any utility rate proceedings or other ratemaking proceedings?

A. Yes. I have testified in several proceedings, most recently in Case 10-E-0050 that established rates for National Grid.

Q. What is the purpose of the Panel’s testimony in this proceeding?

A. Our testimony provides background and perspective to the rate proposal made by PSEG LI, and addresses accounting and ratemaking aspects of the rate filing. We will summarize the rate filing from a revenue requirements perspective, and explain by cost category the increases contributing to the requested rate increase. We will discuss (1) the criteria used by Department Staff, or Staff, in the evaluation of the filing, (2) a summary of Staff’s adjustments to budgeted costs, and (3) a summary of Staff’s revenue requirement recommendations. We will also discuss LIPA’s cost structure and explain how financial data prepared using generally accepted accounting principles, or GAAP, has been translated into the Public Power model used for the rate filing.

Q. Will any other items be discussed?

A. Yes, a number of other areas will be discussed, including a significant proposed accounting change to the Shoreham Acquisition Adjustment, changes to the ratemaking treatment of pension and other post employment benefits, the latter is commonly referred to as OPEBs, the Department’s review of the performance metrics contained in the OSA, and several other recommended adjustments.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. Revised Exhibit___(PORR-1), Schedules 1 through 3, is Staff’s revenue requirement schedule for the three-year rate plan beginning January 1, 2016 through December 31, 2018. Revised Exhibit___(PORR-2) is a summary of the revenue requirements as adjusted by Staff and Revised Exhibit___(PORR-3) is an explanation of Staff’s adjustments. Exhibit___(PORR-4) is a description of LIPA’s cost structure. Exhibit___(PORR-5) is a calculation explaining why a rate increase is warranted in this proceeding.

Q. In your testimony, will you refer to, or otherwise rely upon, any information produced during the discovery phase of this proceeding?

A. Yes. We relied upon LIPA’s response to Information Request DPS-RRP-133. This is attached as Exhibit___(PORR-6).

Q. Why has your testimony been revised?

A. We incorporated three changes into our testimony, each of which affects the revenue requirement. The first change is to correct a mechanical miscalculation identified in the model used to calculate the revenue requirement. The second change is to revise the amounts included in the revenue requirement for swap payments, other income, and debt service. The third change is to eliminate our proposal regarding Pensions and OPEBs.

Q. How do these changes affect the revenue requirements?

A. The mechanical miscalculation which excluded, in Staff’s second and third year calculations, the prior year rate increases requested by PSEG LI, along with Staff’s two additional revisions, caused an understatement of $124.3 million in the incremental revenue requirement. Staff’s original proposal relating to swap payments, other income, and debt service understated the revenue requirement. The revision will be discussed by the Staff Finance and Public Power Panel in its revised testimony. Staff's revision regarding Pensions and OPEBs reduces the total revenue requirement.

Background and Perspective

Q. What is the purpose of the background and perspective section of the Panel's testimony?

A. The purpose of the background and perspective section is to reacquaint the public with the provision of electric utility service on Long Island, and to highlight several issues which may be helpful in understanding rate and other matters facing LIPA, PSEG LI and their customers. LIPA has not been subject to a DPS rate proceeding since prior to approval of the merger between the Long Island Lighting Company and LIPA in 1998. Consequently, public knowledge of its operations may be somewhat limited and at times incomplete.

Pre Hurricane Irene and Super Storm Sandy

Q. Can you discuss LIPA's situation in the period prior to Hurricane Irene and Super Storm Sandy?

A. LIPA was created by the Long Island Power

Authority Act of 1985, which made it the retail electric provider for most of Nassau and Suffolk Counties and part of the Rockaway peninsula in 1998. From the beginning, LIPA, and its customers, carried the burden of dealing with the financial consequences associated with the abandonment of the Shoreham Nuclear plant project. The cost of carrying this unproductive asset on LIPA’s books continues to be considerable, and it currently generates $112 million in yearly amortization expense. The unrecovered balance of $2 billion continues to require financing until it is fully amortized in 2032 under the current plan, or 2025 as proposed in this rate proceeding and discussed below. Assuming a 4% cost of debt, which is approximately the long term cost of debt Staff has determined to be appropriate in this proceeding, the Shoreham regulatory asset contributes $120 million annually to the revenue requirement in this proceeding, and approximately $360 million for the 2016-18 rate period.

Q. Are there any other issues that significantly

affect Long Island electric rates?
A. As most Long Island residents are aware, property taxes are high on Long Island. LIPA makes payments in lieu of taxes, referred to as PILOTS, in the amount of $298 million, and of the $458 million charged by National Grid under its Power Supply Agreement or PSA with LIPA, $193 million is attributable to property taxes. Property taxes account for approximately $490 million or 13% of the total revenue requirement, that is, base delivery plus fuel and purchased power in this proceeding. This amount assumes limited relief of $16 million by 2016. If there is no property tax relief, the $16 million would be charged to customers under the Power Supply Adjustment, or PSA, component of the Delivery Service Adjustment, referred to as the DSA, proposed in this proceeding. The DSA is discussed by the Staff DSA and Storm Reserve Panel.
Q. Please describe LIPA’s capital structure.
A. LIPA is approximately 97% debt financed, with only 3%, or $435 million, of capital coming from internally generated funds. This high degree of

leverage is one of the primary factors that make LIPA a relatively higher credit risk compared to other large public power utilities.

Q. Why does LIPA have such a high degree of leverage?

A. Having only increased rates twice since 1985, LIPA’s reluctance to increase delivery rates to recover the true cost of providing service has required it to raise capital through debt financing, as opposed to internally financing a portion of its construction budget. While the securitizations available to LIPA under the Utility Debt Securitization Authority, or UDSA, will continue to assist in keeping interest costs lower than they would be otherwise, interest expense is still a major component in the revenue requirement, amounting to $365 million in the 2015 budget alone.

Q. Are there any other issues that impact LIPA’s total debt?

A. In January 2000, LIPA reached an agreement with Nassau and Suffolk Counties along with several other parties regarding over assessment of the Shoreham Nuclear Power Station, which we will refer to as the Shoreham Tax Settlement. Under the agreement, LIPA was required to issue $457.5 million of credits to customers over a five year period beginning in 1998. In order to fund the credits, LIPA incurred additional debt.

Beginning in June 2003, Suffolk County customers’ bills include a surcharge to be collected over a 25-year period to repay the debt service. Currently, LIPA has over $500 million in debt service on its books as a regulatory asset associated with this settlement. This surcharge does not directly affect the revenue requirement because it is collected as a separate line item on customers’ bills, and therefore is not included in delivery rates.

Q.   What is the relevance of pointing out these factors?

A.   LIPA’s financial condition is fairly intractable and is difficult to materially change in the short run. Moreover, confronting the underlying basis for LIPA’s existing financial reality will begin to provide a framework for developing a longer term strategy to improve LIPA’s financial situation and to benefit its customers.

Q. Do you have a more complete breakdown of LIPA’s cost structure?

A. Yes, it is included as Exhibit___(PORR-4). A large percentage of LIPA’s costs are difficult, at least in the near term, for LIPA to materially influence. They are considered semi-fixed costs. For example, fuel and purchased power costs are based on a mix of long-term contracts and market-based prices over which LIPA has little direct control over. Fuel and purchased power costs constitute approximately 43% of a customer’s total bill and are included in the Fuel & Purchased Power Cost Adjustment, or FPPCA. In addition to the fuel and purchased power costs in the FPPCA, LIPA has a contract with National Grid to purchase power from the legacy Long Island Lighting Company power plants (i.e., Northport, Port Jefferson, E.F. Barrett). LIPA also has an 18.2% ownership share in the Nine Mile Point 2 nuclear power plant, and has contracted to buy that share of power from this plant. Together with these additional costs, which are included in the delivery portion of customers' bills, approximately 51% of a customer's total bill is dedicated to fuel and purchased power.

Q. Are there any other costs that should be considered semi-fixed costs?

A. Yes, Exhibit___(PORR-4) includes a detailed list of LIPA's expenses that are estimated to be semi-fixed costs. Approximately 85% of LIPA's expenses are considered semi-fixed costs.

Post Hurricane Irene and Super Storm Sandy

Q. What happened to LIPA in the post-Irene and Super Storm Sandy period?

A. Customer dissatisfaction with LIPA has been a long standing issue. After two successive years of damaging hurricanes, the Governor convened a Moreland Commission and ultimately the LRA was enacted. In 2014, PSEG LI was chosen to take over for National Grid in running the Long Island electric system. Among its provisions, the LRA increased PSEG LI's role over day-to-day operations and planning for the electric system and expanded State oversight of electric service on Long Island.

Q. What is the relevance of having a new provider take over the day to day operations of the electric system?

A. Transitioning control of a large scale operation increases the likelihood of problems occurring, while significant productivity enhancements may be difficult to achieve until later in the transition. This was particularly true in 2014, which was the first year that the operation of the electric system shifted from National Grid to PSEG LI. The transition will continue, granted on a smaller basis in 2015, with the movement of the power supply function from Con Edison Energy to PSEG LI that occurred on January 1, 2015.

Q. How has PSEG LI performed during this transition period?

A. Progress was made in satisfying almost all metrics set forth in the OSA, which are key measures of PSEG LI’s performance. Also, several major systems were put in place such as a new interactive voice response system, outage management system, and an SAP enterprise resource planning system for financial purposes. SAP is the acronym for Systems, Applications, and Products in Data Processing. These major changes were accomplished with customers hardly appearing to be aware they were taking place. With respect to one of the metrics, Customer Service, PSEG LI generally performed well, but there were inadequacies in Customer Outreach, for example, related to public dissatisfaction relating to the placement of electric poles.

Q. What is the additional relevance of the LRA during this time period?

A. The statute’s provisions created a DPS Long Island office and empowered it with certain responsibilities. The LRA enables the Department to review and make recommendations concerning the operations, terms and conditions of service, and rates and budgets of LIPA and PSEG LI in a similar fashion to other New York utilities, but also allows DPS to take into account the institutional differences on Long Island.

Q. What are some of the benefits that have been, or will be, provided as a result of this DPS review of LIPA and PSEG LI’s operations?

A. In accordance with the LRA, DPS reviewed and commented on two revenue neutral tariff changes proposed by LIPA in 2014 and early 2015, reviewed PSEG LI’s Emergency Plan and related drills, and pursued an aggressive schedule of outreach with the general public, community groups, and elected officials. DPS also resolves customer complaints, performs informal hearings, and recommends decisions on appeals. The DPS will also provide recommendations to LIPA’s Board of Trustees on the appropriate level of revenue requirements in this proceeding, along with a corresponding reconciliation of the factors underlying the need for rates.

Q. What criteria did Staff employ in its evaluation of PSEG LI’s requested rate increase?

A. In accordance with the LRA, the purpose of the Department’s review is to ensure that LIPA and PSEG LI, the service provider, provide safe and adequate service at rates set at the lowest level consistent with sound fiscal practices. Further, the Department’s recommendations are designed to ensure that the revenue requirements are sufficient to satisfy LIPA’s obligations with respect to its bonds, notes and all other contracts. We evaluated the rate increase in the context of its consistency with the practices followed by other New York utilities and examined ways to improve LIPA’s financial soundness and minimize the impact on customers’ rates. Lastly, we evaluated LIPA’s and PSEG LI’s operational parameters in comparison to its historical performance and those of other New York utilities.

Q. Have you performed a calculation explaining why a rate increase was requested in this proceeding?

A. Yes, Exhibit___(PORR-5)details the total change in budgeted costs from the 2015 base year through 2018. The rate proposal is based on a cumulative operating shortfall of $148.9 million by the end of 2018 without a rate increase In addition, the request identified an additional $72.3 million that will be needed to cover debt service. In total, $221.2 million of rate increases is being requested over the three year rate period which equates to $441 million in new revenues.

Q. Are LIPA and PSEG LI anticipating significant cost increases during the rate period?

A. Transmission and distribution costs are budgeted to increase by approximately $91.8 million. Included in this amount is an increase of $9.7 million for property taxes related to the Power Supply Agreement and an increase of $24.2 million for PSEG LI's management fee. Taxes are budgeted to increase by approximately $18.9 million in addition to the $9.7 million noted above. Grants and other income are budgeted to decrease by approximately $21.7 million. Debt service costs are budgeted to increase by approximately $88.7 million, which includes an increase in coverage which will be discussed by the Staff's Finance and Public Power Panel testimony. This includes an increase of $49.5 million in new debt service costs to support new infrastructure and technology investments.

Overview of the Rate Filing and Need for Rate Increase

Q. Please summarize the January 30, 2015 electric rate filing from a revenue requirements perspective.

A. The rate filing contained the request for a rate increase of $72.7 million for 2016, $74.3 million for 2017, and $74.3 million for 2018. This increase would result in an overall electric revenue increase, inclusive of projected electric supply costs of 2.0%, 2.0%, and 2.0% for 2016, 2017, and 2018, respectively, or 3.9%, 4.0%, and 4.0% for 2016, 2017, and 2018, respectively, on a delivery only revenue basis.

Overview of Staff's Revenue Requirement Calculation

Q. Please summarize the Department's projected revenue requirements for the three-year rate plan ending December 31, 2018.

A. Revised Exhibit___(PORR-1), Schedules 1 through 3, show Staff's forecasted electric revenue increase of $20.5 million, $67.2 million, and $79.7 million for 2016, 2017, and 2018, respectively, or a total of $167.4 million in increases which equates to $275.8 million in total revenue requirements over the rate period.

Q. Please describe the format of Revised Exhibit___(PORR-1).

A. Column 1 contains the GAAP income statement. Column 2 through column 10 contain the modifications to convert the GAAP income statement into the public power model. Column 14 is the modified income statement under the public power model excluding the rate increase. Column 15 contains references to the supporting schedules that present Staff’s adjustments set forth in column 16. Column 17 presents Staff’s projected rate year figures before any required revenue increase. Column 18 contains Staff’s proposed changes in revenues, and Column 19 is Staff’s forecasted rate year income.

Q. What is the effect of Staff’s adjustments on the revenue requirements?

A. Staff’s recommended change in the electric revenue increase requested by PSEG LI is a $52.2 million decrease for 2016, $7.0 million decrease for 2017, and a $5.4 million increase for 2018 as compared to the original filing.

Q. Why is Staff recommending a revenue requirement for 2018 that is higher than PSEG LI requested?

A. Staff proposed adjustments to the annual operating budget each year, however, because Staff significantly reduced PSEG LI’s revenue requirement in 2016 and 2017, an increase in

2018 was necessary for LIPA to achieve its operating budget targets. It should be noted that PSEG LI requested a total revenue increase over the three rate years of $441.0 million which Staff reduced to $275.8 million.

Q. What are the major cost categories Staff recommends be adjusted?

A. The adjustments fall into seven major categories: (1) forecasted revenues being addressed by Staff’s Sales Forecast Witness Anping Liu, (2) outreach being addressed by Staff’s Customer Service Panel, (3) infrastructure improvements being addressed by Staff’s Energy Efficiency and REV Panel, (4) transmission and distribution spending being addressed by Staff’s T&D Capital Expenditures Panel and the Transmission and Distribution Operations Panel, (5) inflation and productivity being addressed by Staff’s Inflation, Productivity and Management Audit Panel (6) Nine Mile Point 2 decommissioning expenses which we will also address, and (7) debt service and coverage being addressed by Staff’s Finance and Public Power Panel.

Public Power Model

Q. What financial data did PSEG LI provide for its historic test year?

A. PSEG LI used the 2015 budget approved by LIPA's Board of Trustees as the test year for its three year rate proposal. It adjusted this budget for inflation, activity changes, and productivity adjustments to develop the budgets for 2016, 2017, and 2018. These annual budgets were prepared using GAAP and show an operating deficiency of $58.5 million in 2016 and $16.3 million in 2017, and an operating profit of $18.4 million in 2018. These amounts have been modified under the public power framework to calculate the rate increase needed to ensure adequate cash flow and improve its financial structure and credit rating. These calculations can be seen in Revised Exhibit___(PORR-1). The approach taken in the Public Power model is expected to enable LIPA to recover its current operating costs from customers, meet its debt obligations, and generate an adequate amount of coverage which is similar to retained earnings in an investor owned utility.

Q. Why is it important for LIPA to maintain adequate cash coverage?

A. Cash coverage can be used to fund future capital expenditures. This coverage also assures bondholders and other lenders that LIPA has the ability to meet its future debt obligations. This assurance indirectly translates into lower borrowing costs over time, which will be discussed in Staff's Finance and Public Power Panel testimony.

Q. What changes or adjustments to the budget data are necessary to use the Public Power framework?

A. The Public Power Ratemaking model is distinguishable from the traditional investor owned utility revenue requirements model in that it is a cash-based model. Public power entities recover current operating costs, debt service and coverage from their customers. It is not necessary to collect depreciation of capital assets or amortization of regulatory assets because cash flows associated with these amounts have already been included in the debt service calculations. Therefore, depreciation and amortization is added back to the GAAP operating results. In other words, non cash depreciation expense and amortizations are eliminated as operating expenses. The other large adjustment is for accrued interest expense. Actual interest expense is included in the debt service calculation; therefore, accrued interest expense is also added back to the GAAP operating results.

Q. How are depreciation, amortization, and accrued interest expense already included in the debt service amounts?

A. The cost of debt service includes all of the debt supporting past cash flows, that is, past capital additions and regulatory assets, as well as prospective cash flows for the three year rate period and is included in the revenue requirement. Instead of providing recovery of these non-cash expenses, that is, depreciation and amortization, the Public Power model provides for the recovery of the capital necessary to support the underlying asset or deferred expense.

Q. Are there any other modifications to the GAAP operating results that result from use of the

Public Power model?

A. Yes, there are an additional five adjustments that are made to the GAAP operating results due to the use of the Public Power model.

- Pension and Other Post Employment Benefits (OPEBs) – LIPA recognizes the cash contribution to the pension fund rather than the GAAP actuarial expense in its revenue requirements. In addition, approximately $50 million per year is designated to be funded into the OPEB plan, although these amounts are not included in the revenue requirement, rather they are reflected as a reduction in coverage.
- Shoreham Tax Settlement – this regulatory asset was established when LIPA incurred debt to refund customers for over-collection of property taxes by Suffolk County related to Shoreham. A separate surcharge is included on bills to customers in Suffolk County, where Shoreham is located, and the amount collected from this surcharge is being used to repay the initial debt incurred. An adjustment is made to remove this from

revenue requirements because it is already included in total debt service. This was discussed earlier in our testimony.

- Southampton Visual Benefit Assessment (VBA) – this adjustment is similar to the Shoreham Tax Settlement Adjustment. LIPA incurred debt to bury a portion of a transmission cable in the Town of Southampton and is surcharging the customers in that town over a 20 year period beginning in 2009. The amount collected from this surcharge is being used to repay the initial debt incurred. An adjustment is made to remove this from revenue requirements because it is already included in total debt service.
- Nine Mile Point 2– Each year LIPA is required to fund a portion of the future decommissioning expenses related to its ownership interest in the Nine Mile Point 2 nuclear power plant. A modification totaling $1.1 million each year was included in the rate proposal for this expense.
- Deferred FEMA Grant Income – Each year LIPA recognizes FEMA grant income related to storm

hardening as an offset to the depreciation expense for the assets constructed using FEMA funds. The FEMA grant income is considered a reimbursement from FEMA rather than income. In 2016, $2.2 million in FEMA grant income is projected to be recognized, $6.7 million in 2017, and $11.2 million in 2018. FEMA is contributing 90% of the cost towards these capital assets; and LIPA's contribution is 10%. These assets are being depreciated over the life of the plant which is approximately 57 years. When the assets are depreciated, 90% of the expense is offset by the recognition of the FEMA grant income resulting in a net effect of zero for that 90% on the income statement. The other 10% of the expense is included in total depreciation expense. All depreciation expense is eliminated under the Public Power model; therefore, the offsetting grant income, which also may be considered reimbursement, of 90% is also eliminated.

Q. What is the effect of all of these modifications?

A. After modifications are made to GAAP accounting data for use in the Public Power model, there are excess revenues over expenses of $552.9 million, $608.9 million, and $669.9 million for 2016, 2017, and 2018, respectively. This excess is then used to cover expenses for debt service and enable LIPA to maintain an adequate amount of coverage. Absent a rate increase, this results in a shortfall, inclusive of revenue related taxes, of $72.7 million, $74.3 million, and $74.3 million for 2016, 2017, and 2018 respectively according to the rate filing.

Q. Do you agree with these five modifications?

A. We agree with the modification for the Shoreham tax settlement, the deferred FEMA grant, and the Pensions and OPEBs. We disagree with the treatment of the Nine Mile Point 2 decommissioning expense.

Acquisition Adjustment Accounting Change

Q. Please describe the Acquisition Adjustment.

A. The Acquisition Adjustment, a regulatory asset, represents the difference between the purchase price paid and the net value of the assets acquired from LILCO, primarily the decommissioned Shoreham nuclear plant. The Acquisition Adjustment is currently being amortized on a straight-line basis over 35 years through 2033.

Q. What is the proposed accounting change related to the Acquisition Adjustment?

A. Foster and Associates completed a depreciation study during 2014 and concluded that there was a reserve imbalance (surplus) of $815 million. This balance is currently being amortized over the average remaining life of utility plant; however, LIPA is considering offsetting the remaining amount against the unamortized balance of the Acquisition Adjustment beginning in 2016. The surplus balance at that time is projected to be $775 million. A balance sheet offset of the remaining reserve surplus against the Acquisition Adjustment would reduce the amortization period of the Acquisition Adjustment by 7 years.

Q. Do you agree with this accounting change?

A. Yes.

Q. What impact does this accounting change have on the revenue requirements in this case?

A. As previously noted, the Public Power model does not include depreciation or amortizations as part of its revenue requirements because the costs are recovered through the debt service portion of the calculation; therefore, this adjustment will have no impact on revenue requirements. However, the acceleration of amortization will enable LIPA to remove this regulatory asset from its books on a shorter timescale, thus improving its financial profile over time.

OSA Performance Metrics

Q. Do the proposed revenue requirements include the potential incentive payment to PSEG LI for its performance related to the metrics outlined in the OSA?

A. Yes, $9.5 million, $9.8 million, and $10.0 million for 2016, 2017, and 2018 respectively were included and allocated approximately 22% to capital and 78% to operating and maintenance expenses, sometimes referred to as O&M expenses.

Q. Are these amounts in accordance with those specified in the OSA?

A. Yes, the OSA specifies the total incentive payment as up to $8.7 million per year expressed in 2011 dollars. PSEG LI used an estimated inflation factor to convert this amount into 2016, 2017, and 2018 dollars.

Q. What will happen if PSEG LI does not meet the metrics and qualify for the total incentive amount already included in rates for years 2016, 2017, and 2018?

A. LIPA will not be required to pay incentives to PSEG LI if PSEG LI fails to meet the metrics outlined in the OSA. If this occurs during any of the rate years, we recommend that LIPA pay down debt with these funds by passing a credit through the DSA mechanism to customers.

Q. PSEG LI submitted testimony indicating that it had met all of the 2014 metrics except for one. Have you reviewed and verified this statement?

A. The Department is in the process of reviewing PSEG LI’s performance with respect to the 2014 metrics and has not yet determined the amount of incentive compensation due to PSEG LI, if any. This will be the subject of an independent review by DPS to be completed in accordance with the timeframe set forth in the LRA.

Q. When will the review process be complete?

A. In accordance with the OSA, PSEG LI is required to submit supporting performance data to LIPA by March 31, 2015. LIPA will then perform its own evaluation of the data. The LRA requires the Department to review PSEG LI's performance data and LIPA's evaluation of such data, and to make recommendations to LIPA's Board of Trustees with respect to PSEG LI's incentive compensation within 30 days of receipt of such evaluation and information. While we have received some preliminary information, we have not yet received PSEG LI's calculation of its incentive payment or LIPA's evaluation of the data. Upon receipt of the information, the Department will proceed in completing its review. In accordance with the OSA, LIPA must notify PSEG LI no later than June 30, 2015 of the acceptance or disagreement of PSEG LI's incentive compensation calculation.

Other Adjustments

Q. Have any other adjustments been identified?

A. Yes, there is one adjustment that was caused by a mechanical error in the Public Power model.

The model includes a cash expense related to Nine Mile Point 2 decommissioning in the amount of $1.1 million for each of the three rate years. This expense was already included in the expense line item for the Asset Retirement Obligation and adding it as an additional expense in the Public Power model would incorrectly allow recovery of the same expense twice. In response to Information Request DPS-RRP-133, LIPA indicated that this amount was incorrectly reflected in revenue requirements and should be removed. This adjustment is reflected in Staff adjustment #3 and reduces the revenue requirement by $1.1 million for each rate year.

Q. Did you receive any information pertaining to other adjustments that may or may not be contested?

A. Yes, in response to Information Request DPS-TF-433, LIPA provided a list of adjustments that should have been included in the original filing. In addition, PSEG LI submitted an update to the filing on May 1, 2015 related to corrected exhibits for the Capital Budget Panel testimony and Metrics and Safety Panel testimony.

Q. Have you incorporated these adjustments into the revenue requirements calculation?

A. No, not at this time. These updates were received too late to properly and satisfactorily review and incorporate into our analyses; however, we reserve the right to review them during the course of this proceeding and supplement or revise any testimony, as appropriate.

Q. Do you have any concerns with respect to the magnitude of cost changes over the three rate years?

A. Yes, there is a significant amount of uncertainty because Staff relied on forecasts provided by PSEG LI for all three rate years. DPS typically uses a historic test year which enables comparisons to be made to actual data. PSEG LI asserted that it was unable to provide historic cost data due to the transition of financial data from National Grid which did not occur until early 2015. In addition, some costs that are components of the revenue requirement are beyond the control of PSEG LI and/or LIPA andcan significantly vary over the three rate years. During 2016, several of these costs are expected to be known with more certainty for rate years two and three. Although we have incorporated in our revised testimony, revenue requirement recommendations for all three rate years, Staff will be better able to more accurately determine revenue requirements for rate years two and three with information on actual costs and expenses expected to become available towards the end of 2016.

Q. What are some of the key drivers included in rates that are beyond the control of PSEG LI and/or LIPA?

A. A large proportion of personnel employed by PSEG LI are working under a labor union contract that expires in November 2016. At this time, the increased costs associated with the upcoming contract are unknown. Similarly, debt service costs associated with the planned refinancing of a substantial portion of LIPA’s debt are dependent on the economic environment and level of interest rates. At this time, these costs can be estimated, but actual costs which will become known within the next year, may vary significantly. Lastly, property tax obligations may not be reasonably forecasted due to on-going challenges with local taxing jurisdictions.

Q. How can this risk be mitigated if costs can vary significantly from the forecasts provided in the filing?

A. While PSEG LI could recover actual costs through an adjustment mechanism, it is preferable to have base delivery rates reflect the most accurate cost forecast available, therefore, it would be appropriate for Staff to review and audit these actual costs for rate years two and three when they become known beginning late in 2016. Staff will then be in a better position to recommend changes to the forecasts for the second and third rate years at that time.

Q. How would the forecasts be reconciled with actual numbers for the purpose of refining the revenue requirement for rate years one and two?

A. We have not yet determined the specific method by which we may recommend this be done, however, second and/or third stage filings on these discrete issues or a reconciliation mechanism with Staff review would be among the possibilities.

<u>Employee Pensions and Other Post-Employment Benefits (OPEBs)</u>

Q. What is the Department policy regarding the appropriate accounting and rate making treatment for employee pensions and OPEBs?

A. In accordance with the decision in Case 91-M-0890, the amount allowed in rates for pensions and OPEBs is based on the amounts of those benefits that employees earn during the rate year based on actuarial estimates rather than on the cash payments made by the utility for the benefits during the rate year.

Q. Does the rate filing adhere to Department policy?

A. No, purportedly based on the principles underlying the Public Power model, the testimony advocates setting rates based on the cash payments it projects it will make for pension and OPEBs during the three rate years as operating expenses plus the debt service costs on prefunded OPEB costs for the 2,188 employees covered by the OSA. LIPA contends it is appropriate to only include the debt service costs for OPEBs because unlike pensions that are governed by federal requirements, any funding it opts to do for OPEBs is completely discretionary and does not have to be made.

Q. What is the impact on O&M and Capital expenses on a GAAP basis?

A. The full GAAP amount of pension and OPEBs was applied to both the O&M and Capital budgets. However, for ratemaking purposes, the GAAP amount was excluded for O&M. Only the minimum required funding was included for O&M. It should also be noted that the GAAP amount was also excluded in 2015 from O&M because it was deferred as a regulatory asset. This is why there appears to be a significant increase in labor and benefits between 2015 and 2016 for O&M.

Q. What is the impact on revenue requirements if this proposal is accepted?

A. Projected cash payments for pensions and OPEBs are based on the minimum amounts estimated to be required to fund for employee pension costs under federal regulations. The proposal for ratemaking treatment of pensions and OPEBs would result in a significantly lower rate increase than if the rate allowance were based on the accrual method in accordance with Department policy.

Q. Do you agree with this proposal?

A. Yes. Although the rates current customers will be paying for pensions and OPEBs will not reflect the true cost of the services they are receiving, to mitigate the impact of the requested rate increase on customers, implementation of Department policy to Pensions and OPEBs will not be recommended at this time.

Rate Case and Beyond

Q. What future developments are likely to influence the Company’s fiscal situation?

A. As noted above, continuing DPS review will benefit Long Island electric customers and assist LIPA in improving its financial condition. We will strive to ensure that LIPA’s financial strategy will benefit customers in terms of improved credit ratings. The use of the Public Power model is one step along this path.

Also, accelerating the amortization of the Shoreham asset, while it does not directly impact the revenue requirement, will aid in more quickly removing this vestige of the past from LIPA’s books. We believe as well that transparency when implementing practices reviewed or recommended in the rate case process will establish a better performance history for LIPA and PSEG LI and generate additional confidence in Long Island operations.

Q. How do PSEG LI’s operational practices compare to those of other New York utilities?

A. PSEG LI is proposing capital investments that support its daily operations as well as enhance the system to mitigate reliability concerns. From an operations and maintenance perspective, PSEG LI is proposing programs that are more stringent than LIPA’s previous practices and similar to the practices employed by other major New York electric utilities. In limited circumstances, Staff panels – the Transmission & Distribution Operations Panel, the Energy Efficiency and REV Panel, and the T&D Capital Expenditures Panel - have identified practices utilized by other New York utilities that PSEG LI should seek to integrate into its own policies and procedures.

Q. What other future developments may impact the Company?

A. The Integrated Resource Plan or IRP, will provide a comprehensive analysis of Long Island’s resource needs, while the implementation of Utility 2.0, or Reforming the Energy Vision, referred to as REV, in the rest of the state, will afford the opportunity for additional grid improvements. For example, a more distributed underlying network architecture can assist in recovering after a storm which was one reason for the enactment of the LRA. Also, non-traditional means of underwriting the cost of the network and operations by utilizing third party vendors may mitigate the pressure on LIPA’s debt and lead to lower costs for customers.

Q. What does the LRA require concerning energy efficiency, distributed generation or advanced grid technology programs?

A. The LRA requires that LIPA and PSEG LI, on or before July 1, 2014, and annually thereafter, submit to the Department for review, any proposed plan related to implementing energy efficiency measures, distributed generation or advanced grid technology programs with the intent of providing customers with the means to more efficiently and effectively manage their energy usage and utility bills and to improve system reliability and power quality.

Q. Explain the relationship between this yearly filing, which is considered the “Utility 2.0” filing and the State-wide REV proceeding.

A. Although the Utility 2.0 requirements in the LRA are distinct from the REV proceeding, PSEG LI has committed to aligning the Utility 2.0 goals with those of REV.

Q. Are there other benefits from Utility 2.0 to customers?

A. Yes, they are addressed by the Energy Efficiency and REV Panel.

Q. Does this conclude your testimony at this time?

A. Yes.

JUDGE PHILLIPS: Let's go off the record.

(Whereupon, an off the record discussion was held.)

JUDGE PHILLIPS: Staff is going to continue to with the entries by affidavit with the Capital Expenditures Panel and then the Customer Service Panel. I will let you go in order.

MR. MAZZA: Thank you, Your Honor. I would like to submit the testimony and exhibits of the Staff Capital Expenditures Panel via affidavit. The panel consists of Christian Bonvin, Vijay Puran, John Cary and Sean Walters. The documents consist of prepared testimony consisting of 52 pages plus a title page, prepared exhibits including Exhibit CEP-1 consisting of 33 pages, Exhibit CEP-2 consisting of one page plus a cover page and indexes. These were originally prepared May 14, 2015.

JUDGE PHILLIPS: The affidavit for the testimony of the Staff Capital Expenditures Panel has been marked for identification as Exhibit 117. This serves as the basis of copying into the record as though orally given. That testimony of that panel consisting of 52 pages plus a title page.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

In the Matter of a

THREE-YEAR RATE PROPOSAL FOR ELECTRIC RATES AND CHARGES
SUBMITTED BY THE LONG ISLAND POWER AUTHORITY AND
SERVICE PROVIDER, PSEG LONG ISLAND LLC.

Matter Number 15-00262

May 2015

Prepared Testimony of:

Staff T&D Capital Expenditures Panel

Christian Bonvin
Utility Supervisor
Office of Electric, Gas, and Water

Vijay Puran
Utility Engineer 3
Office of Electric, Gas, and Water

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Junior Engineer
Office of Electric, Gas, and Water

State of New York
Department of Public Service
125 East Bethpage Road
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Introduction and Qualifications

Q. Please state your names, employer, and business address.

A. Christian Bonvin, Vijay Puran, John Cary and Sean Walters. We are all employed by the New York State Department of Public Service, or Department. Messrs. Bonvin, Puran and Cary are located at Three Empire State Plaza, Albany, New York 12223. Mr. Walters is located at 125 East Bethpage Road, Plainview, New York 11803.

Q. Mr. Bonvin, what is your current position?

A. I am a Utility Supervisor in the Office of Electric, Gas and Water.

Q. Please summarize your educational background and professional experience.

A. I graduated from the Worcester Polytechnic Institute in 1992 with a Bachelor of Engineering Degrees in Mechanical Engineering and Civil Engineering. I accepted employment with the Department of Public Service in August 1993 and currently work in the Department’s Electric Distribution Systems section. My duties include the technical analysis of capital projects, reviewing operations and maintenance programs, and monitoring the provision of safe and reliable service.

Q. Have you previously testified in utility rate proceedings or other ratemaking proceedings?

A. Yes. I have testified in several proceedings, most recently in Case 10-E-0050 that established rates for National Grid.

Q. Mr. Puran, what is your position with the Department?

A. I am employed as a Utility Engineer 3 in the Bulk Electric System Section of the Office of Electric, Gas and Water.

Q. Please summarize your educational background and professional experience.

A. I graduated from the University of Guyana in October 1987 with a Bachelor of Engineering Degree in Electrical Engineering. In February 1993, I graduated from the City College of New York with a Master of Engineering Degree in Electrical Engineering. I also received a Master of Public Administration Degree from the Nelson A. Rockefeller College, University at Albany, in December 2001. I accepted employment with the Department of Public Service in November 1994.

My duties include and have included the technical analyses of utility rate filings, focusing on revenue allocation, rate design, examination of capital infrastructure projects and budgets, examination of operating and maintenance expenses, and the review and analysis of electric transmission lines under Public Service Law Article VII.

Q. Have you previously testified in utility rate proceedings or other ratemaking proceedings?

A. Yes, I have testified in several proceedings before the New York State Public Service Commission on revenue allocation, rate design and capital infrastructure budgets.

Q. Mr. Cary, what is your position at the Department?

A. I am employed as a Utility Engineer 1 in the Bulk Electric Section in the Office of Electric, Gas and Water.

Q. Please summarize your educational background and professional experience.

A. I graduated from Western New England College with a Bachelor of Science degree in Electrical Engineering in May 1999. I worked for the

USFILTER Corporation as a systems control engineer from May 1999 to April 2000. I worked for the Department of Defense (US ARMY ARDEC) as an electrical engineer in the Precision Munitions Division from May 2000 to April 2004. I also worked as a project manager for a residential homebuilder from April 2004 to March 2012. I have been employed by the Department since March 2012. My current duties include the review and evaluation of electric utility Capital and Operations and Maintenance, or O&M, budgets and expenditures, review and evaluation of Article VII Certificate Applications and production cost modeling using GE MAPS software.

Q. Have you previously testified in utility rate proceedings or other ratemaking proceedings?

A. No, I have not previously testified in utility rate proceedings or other ratemaking proceedings.

Q. Mr. Walters, what is your position at the Department?

A. I am employed as a Junior Engineer in the Long Island Office.

Q. Please summarize your educational background and professional experience.

A. I graduated from Stony Brook University with a Bachelor of Engineering Degree in Mechanical Engineering in 2008. I joined the Department in 2014. My responsibilities include review of electric emergency response plans for conformance with best practices, review of electric utility performance metrics to insure system reliability and service quality, review of capital and O&M expense budgets for adequacy in maintaining reliability and increasing resilience in a cost effective manner, as well as reviewing forecasts and long range system planning.

Q. Have you previously testified in utility rate proceedings or other ratemaking proceedings?

A. No, I have not previously testified in utility rate proceedings or other ratemaking proceedings.

Q. What is the purpose of the T&D Capital Expenditures Panel's testimony?

A. The purpose of our testimony is to address PSEG LI's transmission and distribution, referred to as T&D, capital projects and expenditures as presented by PSEG LI's Capital Budget Panel.

Q. Are you presenting any exhibits in this proceeding?

A. Yes. We relied upon a number of PSEG LI's responses to our Information Requests, or IRs, which are presented as Exhibit___(CEP-1). We also present a summary of our adjustments in Exhibit___(CEP-2).

Q. Please explain the scope of the Panel's review of the proposed capital expenditures.

A. PSEG LI's Capital Budget Panel testimony presented projected T&D capital expenditures for the years 2016 through 2018. The focus of our review was to understand PSEG LI's process for developing its capital budget and to review documentation provided by PSEG LI to support the projects and programs contained in its proposed budget. Where appropriate, we provide specific adjustments to the capital budgets to be incorporated into the revenue requirement calculations. Additionally, we reviewed certain information technology based capital projects that support the operation of the T&D system and recommended adjustments where appropriate.

Q. Are there any projects PSEG LI is undertaking in response to the damage caused by Superstorm Sandy?

A. Yes, PSEG LI will be undertaking storm hardening projects to make the electric system more resilient. LIPA was awarded a grant from the Federal Emergency Management Agency, or FEMA, which will cover the expenditures for projects provided they meet specified criteria.

Q. Are the storm hardening efforts covered by FEMA included in PSEG LI's T&D capital budgets?

A. PSEG LI's capital budget testimony stated it excluded costs for projects contemplated under the FEMA grant. As a result, we will not address the projects or costs to be recovered by FEMA grants or other insurances, other than to verify that those projects are not represented in the general T&D capital expenditure budget. PSEG LI also stated certain capital projects were reduced to reflect the storm hardening efforts that would be recovered under the FEMA grant.

Q. If the storm hardening efforts covered by FEMA are not part of this Panel, how are they being captured?

A. The recognition of costs to be covered by FEMA is included in the revenue requirement. The capital costs are stated in specific line items to clearly separate costs that should be included in base rates and those that should not. Therefore, we will be focused on only the costs that will be recovered through base rates.

Q. As part of the review, did the Panel identify any projects in the PSEG LI's T&D capital budget that should be covered by FEMA?

A. We identified five projects in the 2016-2018 budgets that are related to the impacts of Superstorm Sandy. The projects are the Rockaway Beach – Replace 4 kV Banks and switchgear at $3.6 million in 2016, Long Beach – Replace first and second half switchgears and control cables at $6.7 million in 2016, Far Rockaway – Replace 33 kV Switchgear, Control Wiring, and Control Panels at $5.5 million in 2016, Far Rockaway – Replace 69 kV inter-panel wiring & Control Cables at $600,000 in 2017, and Far Rockaway – Replace Distribution Switchgear at $5.7 million in 2016. The funding requests for some of these projects clearly identify that the costs may be eligible for recovery under the FEMA grant or insurances.

Q. How did the Panel treat these costs?

A. We determined that the projects were needed and that the funding should remain in the T&D capital budget until it is clear that the FEMA requirements are met and costs recovery assured. We do recommend that PSEG LI make all efforts to meet the FEMA requirements because it will provide the best storm hardening with respect to flooding. Should any of the costs be recoverable from sources other than the ratepayers, we recommend the over funding in the budget be used for customer benefit under Staff's proposed Delivery Service Adjustment mechanism, discussed in the Delivery Service Adjustment and Storm Reserve Panel.

Q. Are there other capital projects being proposed that focused on reliability, but not considered storm hardening?

A. Yes, PSEG LI has proposed several projects related to reliability. These projects are designed to replace aging infrastructure, provide a level of redundancy to minimize service interruptions, and ensure that the system operates within design limits.

Q. How is PSEG LI's reliability performance measured?

A. Appendix 9 of the Amended and Restated Operating Services Agreement, or OSA, contains 21 performance metrics, three of which directly relate to system reliability. These are: (1) the System Average Interruption Frequency Index, or SAIFI, (2) the Customer Average Interruption Duration Index, or CAIDI, and (3) the System Average Interruption Duration Index, or SAIDI. All three metrics above are computed in accordance with IEEE standard 1366 and consistent with New York practices, but exclude outages due to Major Storms consistent with the Department's definition that is used by other New York utilities. The OSA also sets performance targets to measure whether PSEG LI's performance is acceptable.

Q. Please elaborate on how these measures relate to the capital program.

A. SAIFI is a measure of frequency, or the number of times a customer's service is interrupted for an extended period. Infrastructure investments and changes to the capital budget have the largest impact on this measure. CAIDI is a measure of duration, or how long an interruption lasts.

SAIDI is a combination of the two. Workforce management practices influence duration the most; however, SAIDI shows positive results if interruptions are kept low due to the nature of its calculation.

Q. Where capital investments and frequency performances are related, what is PESG LI's performance for SAIFI in 2014?

A. As of December 31, 2014, PESG LI's frequency performance was 0.72; better than the target performance of 0.90. PSEG LI's frequency performance is better than most upstate electric utilities, which average between 1.0 and 1.15 over the past five years. Only Consolidated Edison Company of New York has a lower performance average.

Q. Will the Department be tracking PSEG LI's performance each year?

A. Yes, one of our oversight activities will be to monitor PSEG LI's performance and determine if it is implementing the capital program in an appropriate manner that is responsive to its frequency and duration performances.

PSEG LI Budget Process

Q. As part of your analysis did you review the PSEG LI process for developing its capital budget?

A. Yes, we reviewed the budget development process, including the timing of the budget cycle, prioritization of projects, and the approval process conducted prior to finalizing the budgets.

Q. What is your overall impression of the budget process?

A. We found that PSEG LI's process to identify and prioritize projects to be included in the budget is reasonable and similar to other utilities in the state. Projects are proposed based on mandates, loading forecasts, or reliability concerns, and prioritized based on need and risk analysis to help identify which projects would be best to undertake and at what overall cost. Once all projects are ranked, PSEG LI develops a list of projects to be undertaken, beginning with the higher priority ones, while balancing the overall funding requirement. The budget process starts early in the year resulting in a preliminary project listing and budget by the end of June. The budget is reviewed and modified, as needed, by a Utility Review Board, or URB, before it is presented to the LIPA Board of Trustees for final approval in December.

Q. How does PSEG LI prioritize projects?

A. PSEG LI stated it uses a Project Prioritization and Risk Assessment protocol to identify the importance of a project and scores the project on a scale of 1-100. The protocol is based on four factors: Regulatory Compliance, Customer Satisfaction, Financial Performance, and Technical Performance. Within each category are risk drivers that are scored separately before being aggregated into a final project prioritization score.

Q. What is the Panel's opinion concerning the role of the Utility Review Board in the budget process?

A. The concept of a Utility Review Board for approving projects is valid. The scope of what is presented to it, however, needs reform. Our review of the information provided to the URB identified that for most projects, little data on actual spending to date within the budget year is presented to the URB when a change of funding is requested for a project. There is also a lack of visibility with respect to certain high cost blanket projects. Simple variance reporting for each project is not presented to the URB although the information was available for our review during discovery. However, the variance reports we reviewed were not readily comparative to the information in the URB reports. For example, a single line item in the URB may be comprised of several line items in the corresponding variance report. Further, without historic spending and variance information at hand, it is difficult to understand how mid-year requests for funding changes are processed for approval by the URB.

Q. Are there any other concerns with the information presented to the URB?

A. Yes. Major investment projects, such as new substations and transmission lines over $1 million in cost, do not include any engineering drawings, detailed estimates, or work schedules to understand the activities to be taken in the near-term and how it relates to the funding forecasts. Total project costs are generally provided as substation work, conversion and reinforcement work, or transmission work only. The expenditures presented to the URB by year are lumped together into a “base” and only broken apart as being distribution or transmission in nature. More visibility into what the funds will be spent on for these large projects is recommended.

Q. Do you identify any other area of concern with regard to the capital budget process?

A. Yes, our review found that PSEG LI’s treatment of blanket accounts is inconsistent with other New York utilities in New York State.

Q. Please describe what is meant by a “blanket account”.

A. Blanket accounts are used to capture and summarize numerous, small routine capital expenditures such as new customer services, street lighting, and repairing minor damage or equipment failures.

Q. Does PSEG LI have blanket accounts and are they in line with the concept you described?

A. Yes. PSEG LI has identified several blanket accounts within their capital budget. One of our major concerns, however, is that PSEG LI considers blanket projects to be an aggregate of multiple projects with costs less than $1 million each. The $1 million level per project is inordinately high when compared to other large utilities in New York that limit an individual project to $100,000 or less to be chargeable against a blanket account.

Q. Why is this difference in levels such a concern?

A. The defined levels for blankets generally align with the approval process necessary prior to expending funds for a project. PSEG LI incorrectly used the term blanket when summarizing a small number of higher cost projects associated with a program or an overarching objective. By doing so, it constrains the ability of the URB, or other parties, to clearly identify what work is being considered to be performed. The $1 million threshold value is so high that it may also impact the tracking of the actual expenditures and variances for individual projects, as the blanket in total may appear in line with the budget.

Q. What do you recommend to resolve this concern?

A. We recommend that PSEG LI reduce the blanket threshold to $100,000 and provide more visibility to projects between $100,000 and $1,000,000. This would result in a capital budget where projects over $100,000 would be treated similarly to how PSEG LI lists specific projects.

Review of Capital Expenditures

Q. Please summarize PSEG LI's proposed capital budget with regard to T&D infrastructure and its operation.

A. PSEG LI's Capital Budget Panel filed testimony with proposed T&D budgets of $350 million, $371 million, and $370 million for the years 2016 through 2018, respectively, as shown in PSEG LI's Exhibit CBP-2. The forecast includes funding for projects related to reliability, load growth, and mandatory requirements.

Q. Please explain the review process used by the Panel to assess PSEG LI's proposed capital budgets.

A. We reviewed the internal documentation and studies used to develop and justify a project or program merits. We focus on items such as the scope of work and how it would improve the system, whether alternatives were evaluated, historic spending trends for similar activities, and the development of project cost estimates. We also analyzed whether a project may not be required to be constructed within the timeframe in which rates are being set and made adjustments accordingly, thereby mitigating the impact to ratepayers.

Q. Did PSEG LI identify any changes to the budget forecast?

A. Yes. In its response to IR DPS-CBP-0372, PSEG LI provided budget forecasts of approximately $361 million, $337 million, and $382 million for 2016-2018, respectively. PSEG LI stated that the amounts shown on Exhibit CBP-2 needed to be increased by approximately 14.3% to reflect the Administrative and General, or A&G, costs and the Pensions/OPEB costs used in the Ratemaking and Revenue Requirement Panel’s Exhibit RRP-1. In the response, PSEG LI also made significant budget changes to a limited number of projects when compared to Exhibit CBP-2. Many of these limited budget changes, mostly reductions, aligned with questions that were raised in our information requests.

Q. Do capital projects normally account for A&G and Pensions/OPEBs?

A. Yes. When capital expenditures for projects are determined, loaders for A&G and Pensions/OPEB are embedded in the initial labor estimates. We do not have a clear understanding, however, as to why PSEG LI proposes to load the base T&D capital expenditures for A&G and Pensions/OPEB. By doing this, PSEG LI would be applying a loader for A&G and Pensions/OPEB to non-labor components of a project's expenditure, such as materials, which is inconsistent with our understanding on how capital budgets are developed. PSEG LI has not provided any detailed project cost estimates or other information that would clearly demonstrate that the costs proposed in PSEG LI's Exhibit CBP-2 do not already account for A&G and Pensions/OPEB.

Q. What does the Panel recommend with regard to the information provided in IR DPS-CBP-0372?

A. Our review of IR DPS-CBP-0372 determined that the loading factors were actually 14.3%, 15.6% and 16.5% for 2016, 2017 and 2018, respectively.

Because of our inability to determine how the loaders were developed and the unusual method of how it was applied, we recommend that the amount presented in PSEG LI response to IR DPS-CBP-0372 should be “unloaded” for A&G and Pensions/OPEB, using the percentages we just stated. We believe that this should produce an apples-to-apples comparison with Exhibit CBP-2?

Blanket Accounts Forecasts

Q. How are blanket accounts generally forecasted and how did you review them?

A. The exact work activity is unknown at the time the budget is approved for many of the accounts, such as new business, therefore historic trending is used to set the capital expenditure level for the blanket accounts. The exact forecast may be slightly modified to reflect new circumstance, such as reducing the new business account to more appropriately reflect a decline in growth. To ensure appropriate funding levels for these accounts, we typically review a five year history and reasons for deviating from the historic trends. In many instances PSEG LI forecasted a low percent change between budget years, so our key analysis focused on whether the initial 2016 budget request was reasonable.

Q. Were you able to perform such an analysis?

A. PSEG LI could only produce actual spending information for 2013 and 2014 in response to our request for five years of historic data. The URB reports and some of the Project Justification Documents, or PJDs, for the blanket accounts contained additional historical budgets and actual expenditures. Our analysis was based on the maximum amount of data available to determine trends and deviations from prior spending patterns.

Q. What was the result of your review of the blanket accounts?

A. We determined that many of the programs budgets were reasonable and consistent with historic practices. We did, however, identify inconsistencies with the forecasted expenditures for New Business, Electric System Planning, Accidents, Multiple Interruptions, the Substation Reliability Enhancement Program and the Substation Control and Protection Improvements Program.

Q. Please describe the New Business blanket and your concern.

A. The New Business blanket accounts for new customers being added to the system and modifications to the system to enable service installations. Response to IR DPS-CBP-0318 indicated that the 2015 budget was prepared by considering historical spending from 2011 through 2013 together with the 2014 spending forecast as of September 2014. The budget for years 2016 through 2018 are escalated by 3% from the 2015 budget.

Q. Do you agree with this forecast?

A. No, we disagree with the calculation used to establish the forecast. The response to IR DPS-CBP-0318 and the URB reports state that 2013 spending was higher as a result of post Hurricane Sandy customer rebuilding activities. This increased level of spending is not expected to continue. In addition, we believe actual expenditures for 2014 should be considered atypical because it was nearly double the forecasted expenditures.

Q. What does the panel recommend?

A. We recommend not using 2013 data and 2014 actual expenditures in the calculation. Therefore, we recommend averaging actual expenditures from 2010 through 2012 and the 2014 budget, which results in a forecast of $13.26 million. Escalating this average by 3% percent annually results in forecasts of $13.66 million, $14.07 million and $14.49 million for 2016 through 2018, respectively. This represents downward adjustments of $1.83 million, $1.88 million, and $1.94 million for 2016-2018, respectively.

Q. Please describe the Electric System Planning Jobs blanket and your review.

A. Prior to 2015, a blanket account was not specified to fund small conversion and reinforcement work. Going forward, PSEG LI has appropriately established the Electric System Planning Jobs blanket to track this activity. The initial budget level is set at $3.6 million per year and appears reasonable relative to the level of expenditures for accounts such as Public Works and Distribution Station Equipment Failures. Ultimately, we recommend that future budget levels be set based on the trends of actual expenditures charged to the blanket account.

Q. Please describe the Accident blankets and your review.

A. Where nearly all roadways are lined with overhead and underground facilities, the assets are subject to damage by third parties from vehicular accidents or other incidents. The accident program is set up to track charges associated with the repair of these facilities. A historical review of this account showed that the forecasted expenditures are approximately a third of previous forecasts.

Q. What was the reason for this decline?

A. In certain cases, reimbursement of these costs may be obtained through the efforts of the claims organizations. In recent years, the amounts collected from third parties were not posted directly to the accidents blanket. PSEG LI currently post the reimbursements to the accidents blanket. As a result, it has to estimate potential credits and uses the projection to offset the expenditures for this program within the capital budget. This change in accounting methodology resulted in the appearance of a large decrease in the current request for funding.

Q. Does the Panel support this new methodology?

A. Yes, any reimbursements by third parties for accidents should be directly applied to this blanket and forecasts should recognize this, as proposed by PSEG LI.

Q. Please describe the Multiple Interruptions account.

A. The Multiple Interruption program addresses pockets of customers which experience an above average number of electrical interruptions each year. The program is broken into five separate sub-programs, which include (1) Multiple Interruptions, (2) Momentary Interruption Reductions, (3) Airport Industrial Park, (4) Hauppauge Industrial Park, and (5) Targeted Overhead Enhancements. In total, PSEG LI requests $4.84 million for rate year 2016, $8.54 million for rate year 2017, and $10.91 million for rate year 2018.

Q. What is the result of the Panel's review of this program?

A. The first sub-program, Multiple Interruptions, has an unexpected increase, resulting in a total budget of $7.3 million in 2018 for this sub-program. According to PJD Reference B30.1 the historical spending average for years 2009-2013 is $5.1 million. We believe this level is more appropriate because PSEG LI was not able to support the requested increase. Therefore, we recommend funding of $5.1 million be used for 2018, which results in a downward adjustment of $2.2 million.

Q. Please describe the other programs included under this account.

A. The other programs under this account include work to install electromechanical timers to reduce momentary interruptions, programs which target specific high load areas like industrial parks, and a program specifically aimed at villages identified as experiencing widespread reliability problems.

Q. Does the Panel agree with the proposed funding for these programs?

A. Yes. We noticed, however, that the Hauppauge Industrial Area program has changed from being a

10 year improvement program designed to reduce outages to more of an underground cable replacement program for industrial parks.

Q. Please elaborate.

A. PJD 30.4 states that 2012 represented the sixth out of 10 years of funding commitments to improve the area. Therefore, 2016 would represent the final year of the program and funding should be discontinued afterwards. IR DPS-CBP-446 requested justification for the 2017 and 2018 funding levels. PSEG LI's response to this IR stated the goal of the 10 year program was completed; however, aging cables were still in need of replacement not only in the Hauppauge Industrial Area, but in other areas, such as the Heartland Industrial.

Q. What does the Panel recommend?

A. We recommend organizing this targeted cable replacement work as a new blanket program to be listed as a separate line item in the capital budget. The program description should be altered to explain that the purpose is the general replacement of aging and deteriorated cable within various industrial parks on Long

Island as opposed to work focused on reducing higher than desired outage rates.

Q. Please provide a brief description of the Substation Reliability Enhancement Program.

A. The Substation Reliability Enhancement Program is a blanket program consisting of twelve sub-programs geared towards reducing the likelihood of equipment failures. Examples of the sub-programs include a program designed to extend the life of certain transformers and a program to replace tap changers.

Q. What did the Panel find in its review of this program?

A. We identified two large scale projects with individual project costs of more than $1 million in the 2018 budget that should be categorized as specific projects.

Q. What are these projects?

A. The first project is the Substation Transformer Replacement Program, which addresses aging equipment and establishes parameters for transformers to be replaced on a scheduled basis prior to failure. The Substation Transformer Replacement Program is funded at $1.64 million for 2018, which is significantly higher than a majority of the funding for other sub-projects within the Substation Reliability Enhancement Program. In response to IR DPS-CBP-303, PSEG LI stated that the Substation Transformer Replacement Program "should have been categorized as a specific project since it is estimated at greater than $1 million." We agree with this rationale and recommend that this program be re-categorized as a Specific Program. The second project is the Redesign and Rebuild Load Tap Changers project, which is funded at $2.88 million for 2018. Similar to the Substation Transformer Replacement Program, this sub-program is significantly higher than a majority of the funding for other sub-programs within the Substation Reliability Enhancement Program because it is a single project that exceeds the $1 million threshold for what PSEG LI considers a blanket project.

Q. What is the Panel's recommendation for the Substation Reliability Enhancement Program.

A. We recommend that the Substation Transformer Replacement Program and the Redesign and Rebuild

Load Tap Changers project, $4.52 million combined, be removed from the Substation Reliability Enhancement Program and be added to the "specifics" portion of the budget.

Q. How will this change impact the funding proposed by PSEG LI for the Substation Reliability Enhancement Program.

A. As shown in PSEG LI's Exhibit CBP-2, the proposed capital expenditures for the Substation Reliability Enhancement Program are $1.92 million for year 2016, $1.43 million for year 2017 and $6.93 million for year 2018. Relocating the two mentioned projects would reduce the forecast for 2018 to $2.4 million, which is more in line with the other year's forecasts for projects within this blanket program.

Q. Please describe the Substation Control and Protection Program and the discrepancies identified.

A. The Substation Control and Protection Program is a blanket program consisting of 18 sub-programs geared towards improving Substation Control and Protection equipment to reduce the likelihood of equipment failures. As shown in Company Exhibit

CBP-2, PSEG LI proposes funding of $4.64 million for year 2016, $4.30 million for year 2017, and $10.72 million for year 2018.

Q. What did the Panel find in its review of this program?

A. According to PSEG LI’s response to IR DPS-CBP-443, all sub-program costs were within the range of $15,000 to $595,340, except for the Relay Upgrades to Microprocessor Program, which had significantly higher funding in 2018 compared to any other sub-program. In response to IR DPS-CBP-443, PGEG LI states, “[t]he 2018 proposed budget contains a $7 million entry for a Relay Upgrades to Microprocessor Program. This is a placeholder for additional relay upgrades.” We determined that five other Microprocessor Relay Upgrade projects were budgeted for in 2018 under the same PJD B32.15 as the Relay Upgrades to Microprocessor Program placeholder. The average budget for these five projects was $200,000.

Q. Is this placeholder of concern?

A. Yes. There is no clear reason why this placeholder funding is needed given that other similar projects are funded under the same blanket program. We believe that if blanket funds are more than doubled due to a single program, that program should be given its own line in the budget to provide clear visibility as to what the expenditures are. In addition, because this account has so many sub-components, it is important to maintain the historic integrity of the funding levels for future budgeting purposes.

Q. What is the Panel's recommendation for the Substation Control and Protection Program?

A. Due to the fact that this blanket account already includes Control and Protection Relay Upgrades to Microprocessor programs in 2018 and a lack of support for the $7 million placeholder, we recommend that the Relay Upgrades to Microprocessor Program cost of $7 million be removed from the Substation Control and Protection Program budget, resulting in a downward adjustment of $7 million for year 2018.

Q. How will this change impact the proposed funding for the Substation Control and Protection Program?

A. Removing the Relay Upgrades to Microprocessor

Program placeholder would reduce the budget for 2018 to $3.72 million, which is more in line with the other year's forecasts.

Q. What information was provided that impacted the review of the Distribution Automation program?

A. In response to IR DPS-CBP-0372, PSEG LI removed all funding associated with this program. As a result, we have reflected this reduction by PSEG-LI in Exhibit__(CEP-2).

Specific Accounts Forecasts

Q. How did you typically review projects with major spending forecasts?

A. We review projects with major spending forecasts in multiple ways. First, we review any overarching program that drives a project or several projects. Next, we review the individual projects to determine how it fits in with the overarching program and if the costs estimates are reasonable. For projects that are not related to an overarching program we evaluate the need, timing and cost for the project on a case-specific basis.

Q. Are there times when individual projects under a program may not be fully developed?

A. Yes, we expect projects in the future years to be less developed than work being performed in 2016. Placeholders would allow appropriate funding to be set while allowing time to fully develop the scope and prioritization of the project.

Q. Did PSEG LI have any placeholders?

A. Yes, PSEG LI utilized a placeholder for the Conversion and Reinforcement and New Exits Program. This program was individually valued at greater than $1 million. The overall budget was based on an expenditure level of $20.10 million in 2015; $3.6 million of which was allocated to a blanket account. As part of PSEG LI's filing, they identified two projects that are chargeable against this placeholder account. These projects are the Mitchell Gardens new exit feeder with a budget of $3.64 million in 2016 and the Bayport – New feeder, Serota, projects with a budget of $2.15 million in 2016 and $2.16 million in 2017. As a result, the placeholder account forecasts $10.80 million in 2016, $14.44 million in 2017, and $16.60 million in 2018.

Q. What is the Panel's view of this placeholder?

A. While the overall spending level seems appropriate based on historic spending, more detail related to work activities to be undertaken is necessary to ensure these costs are adequate, particularly for work to be performed in 2016.

Q. Please describe the challenges you faced when reviewing the proposed capital budget for the specific accounts.

A. Although PSEG LI's testimony described a few projects, the filing, including its work papers, contained little detailed scope and support for the proposed expenditures for most of the larger T&D projects and programs being contemplated. This information is necessary for proper review of PSEG LI plans and is vital to the Department's mission which is to provide New York rate payers with safe, reliable electric service at just and reasonable rates.

Q. What were you able to determine, given these challenges?

A. Information contained in the PJDs and responses to some IRs, allowed us to verify that PSEG LI had determined the need for several projects and had considered various alternatives to the recommended projects. Some examples include the Shelter Island substation and work related to Fire Island substation.

Q. Please describe the Shelter Island project.

A. PSEG LI is seeking to construct a substation to better serve the customers on Shelter Island, following an initial cable failure and unsuccessful attempt to replace the underwater cable with a new submersible cable. PSEG LI included a project cost of $25.4 million for 2016 in Exhibit CBP-2, which was later modified to $10.5 million in 2016 and $6.9 million in 2017. These revised numbers do not reflect loadings for A&G and Pension/OPEB.

Q. Are you satisfied with the need and timing of the projects?

A. Yes. We are satisfied with the need for the proposed project because the substation will connect to an existing transmission line and restore PSEG LI's ability to serve customers if loss of service on an existing cable occurs.

Q. Please describe the Fire Island Upgrades.

A. PSEG LI proposes five projects to solve three problems or contingencies on Fire Island that would restrict the system’s ability to transfer load between substations on Fire Island if the loss of certain transmission lines occur. These projects, shown on PSEG LI’s Exhibit CBP-2 are: 1) Captree-Robert Moses Trans Cable Circuit 23-738, 2) Ocean Beach-Fire Island Pines Transmission Cable Life extension & N-1-1, 3)Ocean Beach Fair Harbor & Robert Moses-Fair Harbor Cables 23-749 & 23-742, 4) Bayport-Fire Island Pines and Other Circuits Splices Improvements, and 5) Fire Island-Brightwater-Captree Upgrade OH 23-747 Transmission Supply. Together, the proposed capital expenditures for these projects are $18.3 million in 2016, $20 million in 2017, and $13 million in 2018.

Q. Are you satisfied with the need and timing of the projects?

A. Yes. In PSEG LI’s response to DPS-CBP-0335, it provided a matrix to show the interrelationship between the projects and the contingencies they would solve. Four projects will help solve two immediate contingencies and one project, the Fire Island-Brightwater-Captree Upgrade, will help solve a contingency in 2024. While delaying the

Fire Island -Brightwater-Captree Upgrade is possible, it is also reasonable to have this project completed in 2018, as proposed, because in addition to helping to solve the contingency in 2024 it will help improve the reliability of the area once the upgrade comes into service.

Q. Has PSEG LI evaluated the use of REV type solutions, or Non-wires alternatives to the Fire Island Upgrades?

A. Yes. In its response to DPS-CBP-0335, PSEG LI states that:

> The necessary load relief required for alleviating these risks through utilizing a REV like project would require a range of 2 - 6.5 MW load relief at each of a multiple number of Fire Island substations. This REV type of solution was not considered practical due to the varying amount of load relief that must be combined with the number of locations requiring relief in order to effectively address all the contingencies.

We believe that this explanation is reasonable given that the overarching project is very complicated and is geared to solve multiple contingencies.

Q. What are the capital expenditures for the Fire Island Upgrade projects?

A. In response to IR DPS-CBP-0372, PSEG LI increased the proposed spending on the Ocean Beach-Fire Island Pines Transmission Cable Life extension & N-1-1 project in 2016 and reduced it in 2017 by an equivalent amount. The new proposed capital expenditures, without loadings for A&G and pension/OPEB, for the five projects are: $19.9 million in 2016, $18.4 million in 2017, and $13 million in 2018, for a total of $51.3 million over the three rate years.

Q. Please describe the Ruland-Plainview New Transmission Circuit and the Old Bethpage substation projects.

A. PSEG LI Capital Budget Panel, at page 26, stated that the Plainview to Ruland Road – New 69 kV Transmission Line is needed because the existing 69 kV circuit between the Ruland Road and Plainview substation experiences post contingency overloads for the loss of the Syosset Breaker 630 or for the loss of Syosset to Woodbury 69 kV transmission line. The Panel also claimed that several major load additions totaling about 30 MVA are proposed for the Plainview area in the next 2 to 5 years and this would further exacerbate the loading on the existing Ruland to Plainview 69 kV line. Consequently, the Panel opined that a new Old Bethpage substation could be required. This new substation would be fed by tapping into to the new Plainview to Ruland Road mentioned above.

Q. Discuss your assessment of the need and timing for the Ruland-Plainview New Transmission Circuit project.

A. Our review of the PJD S1.1 indicates that a contingency that causes the existing Ruland to Plainview 69 kV line to overload could require shedding approximately 18 MVA of load during peak usage hours. To solve this problem, it is reasonable to build the proposed 69 kV transmission circuit between Ruland and Plainview, which would improve reliability in the area and also serve a new Old Bethpage substation if or when it is built. We note, however, at the Technical Conference on March 3, 2015, PSEG LI indicated that it intends to issue a Request for Information, or RFI, to seek approximately 20 MW of capacity relief through REV type projects, which could defer this project. This was confirmed in response to IR DPS-CBP-0372 where it indicated that the project is currently on hold.

Q. What do you recommend for the Ruland-Plainview New Transmission Circuit project?

A. Given the importance of this project, if a favorable outcome is not obtained from the proposed RFI to defer this project, we recommend that PSEG LI proceed with construction of the new Ruland-Plainview 69 kV transmission circuit. The recommended cost treatment for this project is discussed in the Staff Energy Efficiency and REV Panel testimony. This project is one of the five load pocket projects discussed in that testimony.

Q. Discuss your assessment of the need and timing for the Old Bethpage substation project.

A. We do not recommend that PSEG LI proceed with the construction of the Old Bethpage substation at this time. According to its response to IR DPS-CBP-0420, acquiring suitable land for the substation is still in progress. In addition, need for the substation is dependent on future load additions which have been contemplated for years, but have so far failed to materialize as evidenced in PSEG LI response to DPS-CBP-0420. Moreover, the substation is contingent upon the construction of the new Plainview to Ruland Road 69 kV transmission line which is currently on hold pending the outcome of an RFI, as we discussed above.

Q. What capital expenditures do you recommend for the Old Bethpage substation project?

A. We recommend that PSEG LI’s proposed capital expenditures of $300,000 in 2016 and $2.4 million in 2017 be approved to facilitate purchase of land and engineering for a potential future substation. We further recommend that the 2018 proposed budget be reduced by $13 million, given the uncertainty surrounding this project. Should the situation develop where the substation needs to be built, PSEG LI should re-prioritize its 2018 budget to accommodate this project.

Q. Has PSEG LI identified any project that is needed to meet North American Electric Reliability Corporation, or NERC, Bulk Electric System reliability requirements?

A. Yes, PSEG LI has identified two capital projects; the East Garden City to Valley Stream and the Syosset to Shore Road projects to address N-1-1 criteria violations.

Q. What is an N-1-1 violation?

A. An N-1-1 violation occurs when specific performance criteria required under NERC's Transmission Planning are not met after a Bulk Electric System, or BES, transmission element fails, system adjustments are made, and loss of another BES element occurs. Simply put, the BES should be able to withstand loss to two major transmission elements without negatively impacting reliability.

Q. Please describe the East Garden City to Valley Stream 138 kV project.

A. PSEG LI Capital Budget Panel, at pages 32-33, states that based on internal studies of the Barrett area, N-1-1 criteria violations are observed on the existing East Garden City to Valley Stream 138 kV circuit 138-262 for loss of Barrett to Valley Stream 138 kV circuit 138-291 followed by loss of Barrett to Valley Stream

138 kV circuit 138-292.

The Capital Budget Panel further noted that a second N-1-1 criteria violation is observed on the existing East Garden City to Valley Stream 138 kV circuit 138-262 for loss of one Barrett steam generating unit followed by loss of Freeport to Newbridge Road 138 kV circuit 138-461. The Panel states that the addition of a new 138 kV circuit from East Garden City to Valley Stream substations will eliminate all N-1-1 violations in the Barrett area and also provide flexibility for uncertainties in system load growth and impact from generation/renewable RFPs. According to PJD S49.1, the need date for this project is 2020 in order to be in strict compliance with NERC's requirements.

Q. What is your assessment of the need and timing of the East Garden City to Valley Stream 138 kV project?

A. Based on our review of PJD S49.1 and responses to IRs DPS-CBP-0247, DPS-CBP-0425, and DPS-CBP-0426 we agree with the need assessment and timing proposed by PSEG LI.

As indicated in response to IR DPS-CBP-0426, PSEG

LI plans to issue a Request for Proposal to solicit REV solutions in the area. PSEG LI also noted that load relief in the range of 100 MW to 200 MW would be needed in order to defer this project.

Given the long lead time necessary for a project of this magnitude and the fact that compliance with NERC's requirements is needed by 2020, PSEG LI must make a timely decision based on the responses to the RFP on whether to defer the project, use a combination of load relief and possibly other smaller capital projects or to go with this project in order to be in compliance with NERC's requirements by 2020. The recommended cost treatment for this project is discussed in the Staff Energy Efficiency and REV Panel testimony.

Q. Please describe the Syosset to Shore Road 138 kV project.

A. PSEG LI's Capital Budget Panel, at page 32, states that based on internal studies of the Glenwood area, N-1-1 criteria violations are observed on the existing East Garden City to Carle Place circuit for loss of transmission line

Y50 followed by loss of Glenwood GT – Glenwood North Bus circuit. There are also other N-1-1 combinations involving loss of Y50 that result in criteria violations. The Panel states that addition of a new 138 kV circuit from Syosset to Shore Road substations will eliminate all N-1-1 violations in the Glenwood area. According to response to IR DPS-CBP-0428, the need date for this project is 2020 absent REV type solutions to provide about 100 MW to 200 MW load relief.

Q. What is your assessment of the need and timing of the Syosset to Shore Road 138 kV project?

A. Based on our review of PJD S50.1 and responses to IRs DPS-CBP-0246 and DPS-CBP-0428 we agree with PSEG LI's assessment on the need for this project. However, as noted in response to IR DPS-CBP-0428, this project is not driven by a generator contingency followed by another single contingency. If this were the case, a solution would have had to be in place by 2020 in order to be in strict compliance with NERC's requirements. Since there is no strict due date for this project, there is more time to analyze and decide if there are viable REV alternatives to this project.

It its response to IR DPS-CBP-0428, PSEG LI stated that it plans to issue a Request for Proposal to solicit REV solutions in the area. A decision on the timing of the project will be based on the outcome of the RFP combined with the reliability and cost effectiveness of the potential REV solutions. We recommend that PSEG LI's proposal on evaluating the outcome of the RFP be accepted. The recommended cost treatment for the Syosset to Shore Road project is also discussed in the Staff Energy Efficiency and REV Panel testimony.

Q. Please provide a brief description of the System Operation Control Room Modification/Upgrade project.

A. PSEG LI proposed to replace the existing control room in Hicksville with a new Primary Control Center. It claimed that the big board in the existing control room is grossly undersized to operate the system in a safe and efficient manner. The new control room would add new technology such as video display walls, situational displays and video charts. In addition, the new control room would improve the system operator’s ability to quickly identify lines and equipment during emergency situations and help to minimize the chance of switching errors, which could lead to financial penalties as explained in the response to IR DPS-CBP-0348. PSEG LI further proposed that the project be completed in two phases. The first phase would hire a design contractor and the second phase would involve construction and commissioning activities based upon the contractor’s recommendations.

Q. What level of capital expenditure does the PSEG LI propose for the System Operation Control Room Modification/Upgrade project?

A. In Exhibit CBP-2, PESG-LI proposes to spend $5 million in 2016, $25 million in 2017, and $20 million in 2018. However, in its response to DPS-CBP-0372, these costs were significantly reduced to approximately $5 million in 2017 and $10 million in 2018, without loadings for A&G and pension/OPEB.

Q. What is your assessment of the need for the new System Operation Control Room?

A. Based on our review of PJD S48.1 and responses to IRs DPS-CBP-0348, DPS-CBP-0349, and DPS-CBP-0349 Supplemental, we agree with the reasons provided by PSEG LI for a new control room. Staff of the Department also visited the control room to visually inspect and verify that the existing big board lacks space to accommodate addition of new transmission elements on the board. Staff also verified that the current control room cannot accommodate a larger board. As a result, we are satisfied that a new control room should be built at another site.

Q. What is your assessment of the timing for the new System Operation Control Room?

A. The timing for the new System Operation Control Room cannot be determined at present. No site for the new control room has been identified so far. Furthermore, in its response to DPS-CBP-0349 PSEG LI stated that the first phase of the study to firm up project details, timing and costs, has not yet been approved to proceed by the Utility Review Board for 2015.

Q. What level of capital expenditures do you recommend for the new System Operation Control

Room?

A. Given the importance of this project, we believe that some funding must be allowed even though the timing cannot be established at present. We also believe that the levels proposed by PSEG LI in its response to DPS-CBP-372 are reasonable. Therefore, we recommend PSEG LI be allowed $5 million in 2017 and $10 million in 2018. These numbers do not reflect loadings for A&G and Pension/OPEB.

T&D Capital Budget Recommendations

Q. Given the difficulties expressed in verifying that the costs are reasonable, how does the Panel recommend the three-year budget be set?

A. We recommend using a macro level approach to setting the capital budget, as opposed to our individual project adjustments. We believe this approach is appropriate because our review found that the projects identified have merit and are being implemented at a reasonable time.

Q. Would the Panel please walk us through how your recommended budget was determined?

A. Yes. We started with the budget filed in PSEG LI's Exhibit CBP-2. We then recognized the budget adjustments filed in IR DPS-CBP-0372 that were not associated with A&G and Pension/OPEB, as previously discussed. Blanket accounts were further reduced by our recommend project adjustments. A summary of the recommended budget for blankets is provided in Exhibit__(CEP-2). For specific projects we did not make individual project adjustments other than to remove $13 million of the proposed cost for 2018 associated with the Old Bethpage substation project.

Q. What was the result?

A. Using our approach, we recommend total capital budgets of approximately $314 million, $289 million, and $304 million for 2016-2018, respectively. This equates to total negative adjustments of $36.4 million, $81.9 million, and $66.7 million for 2016-2018, respectively, when compared to the original budget levels in PSEG LI’s Exhibit CBP-2.

Q. Why does the Panel believe this is fair?

A. The levels set are in line with historical budgets and actual investment levels provided in IRs DPS-Preliminary-0048 Supplemental and DPS-

CBP-0448 after removing projects reimbursed by FEMA from 2014.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

JUDGE VAN ORT: What are we up to next?

JUDGE PHILLIPS: Customer Service, I think.

MR. MAZZA: Yes. Thank you, Your Honor. I would like to submit the testimony and exhibits of the Staff Customer Service Panel via affidavit. The panel consists of Irene Luft and Daniel Malesardi. The documents consist of prepared testimony consisting of 23 pages plus a title page and prepared exhibits including Exhibit SCSP-1 consisting of 233 pages, Exhibit SCSP-2 consisting of one page, Exhibit SCSP-3 consisting of three pages, Exhibit SCSP-4 consisting of one page and Exhibit SCSP-5 consisting of one page plus the cover page and indexes. This was pre-filed on May 14, 2015 (handing).

JUDGE PHILLIPS: The affidavit provided for the Staff Customer Service Panel has been marked for identification as Exhibit 118. On that basis, we will ask that the court reporter copy into the record as though orally given the Staff Customer Service Panel testimony consisting of 23 pages plus a title page.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

In the Matter of a

THREE-YEAR RATE PROPOSAL FOR ELECTRIC RATES AND CHARGES SUBMITTED BY THE LONG ISLAND POWER AUTHORITY AND SERVICE PROVIDER, PSEG LONG ISLAND LLC.

Matter Number 15-00262

May 2015

Prepared Testimony of Staff Customer Service Panel:

Irene Luft
Utility Consumer Assistance Specialist 4
Office of Consumer Services

Daniel Malesardi
Utility Consumer Program Specialist 3
Office of Consumer Services

State of New York
Department of Public Service
125 East Bethpage Road
Plainview, New York 11803

Q. Please state your names, employer, and business address.

A. My name is Irene Luft and my co-panel member is Daniel Malesardi. I am employed by the New York State Department of Public Service, the Department. My business address is 125 East Bethpage Road, Plainview, NY 11803.

Q. What is your position at the Department?

A. I am employed as a Utility Consumer Assistance Specialist 4 in the Office of Consumer Services.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor's Degree in Electronics and Communications Engineering from the University of Santo Tomas. I joined the Office of Consumer Services, OCS, for the Department in 2001 as a Utility Consumer Assistance Specialist. I was responsible for responding to and processing utility consumer issues. In 2003, I worked in the Analysis Section of OCS investigating various customer complaints. I also worked as a Call Center Supervisor in the same office. In 2007, I was promoted to manager of the Call Center in the Office of Consumer Services in NYC where my responsibilities included supervising the call center team leaders as well as call center representatives. As manager, I was responsible for developing, updating, and maintaining training materials for staff; resolving complex customer concerns; and monitoring staff for quality assurance and training purposes. In June 2013, I was promoted to my current title as a Utility Consumer Assistance Specialist 4 and subsequently moved to the Department of Public Service – Long Island, or DPS-LI, in January 2014. My current responsibilities include supervising the Informal Hearing and Outreach and Education Units of the Office of Consumer Services at DPS-LI. In order to ensure customer protections and resolve customer complaints, OCS reviews and males recommendations changes to Long Island Power Authority, LIPA or the Authority, and PSEG Long Island LLC., PSEG LI or the Company's, Outreach and Education Plans as well as their Low Income Customers Programs and their Emergency Storm Response Plan as it relates to customer service. As a tool to fulfill its responsibilities, OCS conducts outreach to inform the public of its electric utility service oversight in Long Island.

Q. Have you previously testified in any utility rate making proceeding?

A. No, I have not.

Q. Mr. Malesardi please state your employer, and business address.

A. I am also employed by the Department, and my business address is 125 East Bethpage Road, Plainview, NY 11803.

Q. What is your position at the Department?

A. I am employed as a Utility Consumer Program Specialist 3 in the Office of Consumer Services.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor's Degree in Political Science from Sacred Heart University. In 2007, I began my career working as a Legislative Assistant to NYS Senator Craig Johnson. My responsibilities in this position focused on constituent and community relations, helping citizens challenged by medical expenses, workplace and housing discrimination, veteran's benefits, and other societal issues. I also established an outreach program. The program focused on creating working relationships with local community organizations. In 2011, I was hired as Assistant to the Supervisor of the Town of North Hempstead. I served in the Office of Inter-Municipal Coordination, acting as lead liaison among various levels of government and Town constituents to determine accountability for public action. In April 2014, I was hired by the Department to work at the DPS-LI office.

Q. Please briefly describe your current responsibilities with the Department.

A. My current position focuses on the development of the outreach and education program in the Long Island Office. These programs focus on initiatives including: energy efficiency, energy cost management, and environmental awareness, as well as reviewing utility programs and educational initiatives for consumers. DPS-LI implements grassroots outreach in the Long Island area for DPS-LI, as well as, LIPA and PSEG LI programs, policies and initiatives. I am also responsible for issues relating to

Energy Service Companies.

Q. Have you previously testified in a utility ratemaking proceeding?

A. No, I have not.

Q. What is the scope of this Panel's testimony in this proceeding?

A. We will address PSEG LI's proposals regarding full time employee increases, customer service outreach budget, low income customer needs, and a new customer charge called the "Removal Charge".

Q. Does the Panel have any exhibits?

A. Yes. We are sponsoring five exhibits. Exhibit___(SCSP-1) presents the Information Requests we relied on as part of our testimony. Exhibit___(SCSP-2) shows Staff's worksheet on the proposed budget for institutional advertising. Exhibit___(SCSP-3) shows staff's worksheet on Low Income programs. Exhibit___(SCSP-4) shows the enrollment between HAR and HEAP. Exhibit___(SCSP-5) shows the HEAP enrollment by county.

Customer Service Full Time Employees

Q. Please summarize PSEG LI's proposals regarding the increases in the Full Time Employees, or FTEs.

A. PSEG LI has forecast the need for additional FTEs in its three year rate proposal. It has proposed an additional five FTEs in 2016, five in 2017, and six in 2018. This is a total of sixteen new FTEs over the three year rate plan, and would bring the FTE headcount from 724 to 740 in PSEG LI's entire Customer Service Organization by 2018. PSEG LI has stated that this increase would keep it within an industry top quartile benchmark range of 707-735 employees per million customers, and that the new employees are needed to achieve the customer service metrics targets established by the Amended and Restated Operations Services Agreement, or OSA. These metric targets have been benchmarked to ensure that PSEG LI meets 1st quartile performance in JD Power Surveys by the end of the fifth contract year in 2018. The end result of encouraging PSEG LI's compliance with the metrics is improved customer service for LIPA and PSEG LI customers.

Q. Please describe the purpose or functions of these additional employees as proposed by PSEG LI.

A. PSEG LI indicated in response to DPS-CSP-0198 that seven FTEs will be utilized in the Call Center to support the achievement of the Average Speed of Answer (ASA) first quartile target of 26 seconds; two FTEs will be utilized to support the back office billing work associated with AMI implementation; four FTEs will be utilized for the increase AMI metering workload; and three FTEs will be utilized as Customer Experience Analysts to support the achievement of the JD Power Residential and Business Surveys first quartile targets of 634 points and 654 points respectively. See Exhibit___(SCSP-1).

Q. Do you support PSEG LI's request for the seven FTEs in the Call Center?

A. Yes. PSEG LI justified the need for additional seven FTEs in the Call Center; two in 2016, one in 2017, and four in 2018.

Q. How did Staff make this assessment to support the seven FTEs in the Call Center?

A. The Company utilized modeling software that incorporates Erlang Calculations to determine staffing levels in the Call Center. The Erlang Calculations are an industry accepted standard for forecasting staffing levels in a call center. The model determined that PSEG LI will need 146 call center representatives (CSRs) in 2016, 150 CSRs in 2017, and 152 CSRs in 2018 to achieve the metrics of an ASA of 26 seconds by 2018 as required in the OSA. PSEG LI currently has 129 CSRs in the Call Center. PSEG LI’s request would allocate 131 CSRs in 2016, 132 CSRs in 2017, and 136 CSRs in 2018 instead of the model’s forecast. Due to staff increases coupled with efficiency changes that PSEG LI continues to implement, PSEG LI believes the request of an additional seven FTEs in the Call Center is sufficient to meet its goal of an ASA of 26 seconds by 2018. We do not see any reason to dispute the model’s results and in view of the Company’s efficiency projections, we support PSEG LI’s request for an additional seven FTEs in the Call Center for the next three years.

Q. Do you support PSEG LI’s request for additional three FTEs as Customer Experience Analysts; one in 2017, and two in 2018?

A. Yes. We recognize the need for PSEG LI to meet the OSA metrics as an indication of improved customer service. Due to the complexity of the information being provided by JD Power; we concur with PSEG LI’s need for the additional three FTEs in this area to review and implement results from the JD power surveys.

Q. What are the JD Power Residential and Business Surveys?

A. JD Power and Associates is a firm that conducts surveys of customer satisfaction, product quality, and buyer behavior for various industries including utility companies. By analyzing the many aspects of customer experience, JD Power can identify the multiple drivers of that experience, measure and understand the impact of those drivers, and help drive business results by monitoring and improving performance. As indicated earlier, PSEG LI must achieve scores on JD Power Residential and Business Surveys of 634 and 654 points respectively in its first quartile performance by the end of 2018 as an indication of improved customer service.

Q. Do you support PSEG LI’s request for six additional FTEs, two in Back Office Billing and four in Metering Services, associated with AMI implementation?

A. Staff’s Energy Efficiency and REV Panel will address this issue.

Q. Do you have any recommendations regarding future proposals for additional FTEs for PSEG LI’s Customer Service Organization?

A. Yes. PSEG LI justified the need for the 16 additional FTEs using a benchmarking study and this study was cited numerous times as justification to Staff. See Exhibit___(SCSP-1). However, the demographics information on the participating utilities was kept strictly confidential. Staff was unable to determine whether the utilities used were comparable to PSEG LI. Therefore, Staff could not fully utilize the benchmarking study to justify the need for additional FTEs. While Staff was able to justify the new FTE’s using the staffing calculations described above, it would be beneficial in the future to improve PSEG LI’s benchmarking efforts to clearly demonstrate need. We recommend that PSEG LI develop transparency as to the peer group utilized and provide justification for future benchmarking studies as they should directly relate to PSEG LI operations and LIPA's service territory. PSEG LI should, accordingly, conduct its own benchmarking studies rather than leveraging PSE&G's studies. This would then set the parameters of the study squarely on PSEG LI.

Customer Service Outreach Budget

Q. Please summarize PSEG LI's proposals regarding the additional programs outlined in its Customer Service's Panel Testimony.

A. PSEG LI estimates the need for an additional $2,100,000 for each rate year in addition to its current budget of $3,334,800 in support of additional customer education materials and notices programs. This is approximately a 63 percent increase in the spending level for the program. PSEG LI states this is necessary to meet the OSA JD Power Residential and Business metrics and increase customer satisfaction levels. PSEG LI's proposed additional outreach budget increase of approximately $2 Million which is broken down into the following: $2,859 for newsletters; $2,250 for bill inserts; $600 for brochures and flyers; $510 for customer rights pamphlets; $40,225 for financial assistance direct mail; $1,350 for customer rates pamphlets; $739,000 for direct mail; $35,400 for email advertising; $65,000 for outreach events; $878,000 for media; $203,000 for educational videos; $2,460 for tree maintenance correspondence; $7,500 in energy efficiency advertising; $1,350 for life support and special protections correspondence; and $120,540 for storm communications.

Q. What recommendations do you have regarding PSEG LI's proposed increase in outreach budget?

A. We recommend the following negative adjustments: -$240,000 for six Marketing Campaigns, -$550,000 for increased media outreach, -$363,000 for one direct mail to all customers, and -$327,000 for the proposed TV campaigns. Our total negative adjustments equal $1,480,000. See Exhibit___(SCSP-2).

Q. Why are you recommending a negative adjustment to PSEG LI's proposed outreach budget?

A. Staff recommends this adjustment because PSEG LI has not justified the need for the full increase nor has PSEG LI provided a clear illustration of how this increase would be allocated towards positively impacting outreach efforts beyond funding more advertisements. Additionally, PSEG LI stated in its response to DPS-CSP-0431, that the entire increase in outreach budget is allocated to educational, informational, and promotional messaging. PSEG LI states that it does not conduct institutional advertising or create institutional materials. See Exhibit___(SCSP-1). However, in response to DPS-CSP-0332, PSEG LI stated that it has spent a total of $373,131 in institutional advertising regarding its first year performance. See Exhibit___(SCSP-1).

Q. What is institutional advertising and what is the Department’s policy regarding institutional and informational advertising?

A. Advertising expenses can be divided into two categories: promotional which is intended to stimulate the purchase of utility service and institutional and informational which encompasses all other advertising not clearly intended to promote sales. Since, February 25, 1977, the Department has recognized that the costs for institutional advertising are a legitimate expense of doing business. In order to allow other NY utilities the freedom to advertise within their own discretion the Department applies a policy recommending a budgetary allocation of 1/25 to 1/10 of 1% of the company's operating revenues in inverse relationship to the size of the company, with the percentage decreasing as the size of the company increases. Because LIPA is among the larger New York Utilities, Staff recommends that PSEG LI allocate 1/25 of 1% of LIPA's revenue which is $1.5 million of its proposed outreach budget to institutional advertising.

Q. Do you have any other recommendations regarding the Companies outreach and education plans?

A. Staff recommends the Company take the lessons learned from the 2014-2015 contract years, and adjust its outreach program accordingly. Based on input from the public and as evidenced by PSEG LI's to-date outreach efforts on Long

Island, the interaction and communication with customers is of paramount importance. As we have seen in the communities of East Hampton, Port Washington, and East Garden City the existing outreach plan can improve, and should be more community and project centric. The concerns of customers in these communities stem from a disconnect between project based outreach that is done during a transmission project, and PSEG LI's day-to-day customer service outreach efforts directed by their Consumer Services Department. Communities are concerned that there is insufficient communication regarding infrastructure projects. It is important that PSEG LI change this perception and we recommend that it takes clear steps to address these concerns. Staff recommends that PSEG LI develop a more cohesive and comprehensive process where the Consumer Services Department communicates and works collaboratively on outreach.

Low Income Customer Needs

Q. Does PSEG LI currently have special programs for income eligible or low income customers?

A. Yes. There are two income eligible programs;

the first is called the Residential Energy Affordability Partnership, or REAP. REAP is a program for income-eligible customers to help them save energy and lower their electric bills. In this program, eligible customers may receive energy saving measures at no cost. The second is called the Household Assistance Rate or HAR. HAR includes a daily reduction of $0.181 from the Customer Service Charge of $0.36 per day for both heating and non-heating residential customers. This is essentially a reduction of 50% of the Customer Service Charge. To be qualified for HAR, a customer must have received one or more benefits from among a number of social services programs for the past 12 months. These programs include: Home Energy Assistance Program (HEAP); Medicaid; Food Stamps; Temporary Assistance for Needy Families or Safety Net Assistance Administered by the Nassau or Suffolk County Department of Social Services or the New York City Department of Human Resources Administration; United States Social Security Administration Supplemental Security Income; United States Veterans Administration Veteran's

Disability Assistance or Veteran's Surviving Spouse Pension; or New York State Child Health Plus Health Insurance Program. In 2014, there was an average active enrollment of approximately 15,300 customers in HAR, see Exhibit___(SCSP-5). There is also a cap identified in LIPA's tariff of 50,000 customers who can be enrolled in HAR.

Q. Does PSEG LI propose to continue HAR Program?

A. Yes, PSEG LI proposes to continue the HAR program and increase the funding level to insulate income eligible customers from the effects of the proposed rate increase. PSEG LI is also proposing two discount classifications; one is a $0.32 per day reduction in Customer Service Charge for non-heating customers and the other is a $0.49 per day reduction in Customer Service Charge for heating customers. These discount classifications are in addition to its current program where a low income residential customer receives a $0.181 reduction in the Customer Service Charge whether the customer is a non-heating or heating customer. The discounts will remain the same for 2016, 2017, and 2018 despite the proposed increases in Customer Service Charge of $0.50 per day, $0.58 per day, and $0.66 per day for 2016, 2017, and 2018, respectively. This means that low income non-heating customers will pay a customer charge of $0.18 per day in 2016, $0.26 per day in 2017 and $0.34 per day in 2018, and low income heating customers will pay $0.01 per day in 2016, $0.09 per day in 2017, and $0.17 per day in 2018. See Exhibit___(SCSP-3).

Q. What is Staff's recommendation as it relates to PSEG LI'S proposal to increase the Customer Service Charge in 2016, 2017, and 2018?

A. The Staffs Rates Panel recommends maintaining the Customer Service Charge at its current level and keeping it at $0.36 per day for the next three years.

Q. If the Customer Service Charge does not increase, what are your recommendations regarding the proposals to assist the income eligible program customers?

A. We recommend continuing the daily reduction of $0.181 from the Customer Service Charge for income eligible customers to maintain the financial protections afforded to these customers at current rates. We also support PSEG LI's proposal to afford residential customers who use electricity to heat their homes an additional bill discount on their monthly electricity bills. This practice is consistent with the other utilities in New York State because electric heating bills are generally more expensive than any other electricity bills. An additional daily reduction on the Customer Service charge will provide further relief to customers who use electric heating. Therefore, we recommend that PSEG LI provide an additional discount to low income electric heating customers of $0.17 per day from the Customer Service Charge. This means that eligible low income non-heating customers will have to pay a Customer Charge of $0.179 per day and eligible heating customers will have to pay a Customer Service Charge of $0.009 per day. These discounts are comparable to PSEG LI's proposed discounts for heating and non-heating customers with respect to rate year 2016 where it proposed non-heating customers and heating customers to pay $0.18 per day and $0.01 per day respectively in Customer Service Charge. We provided a comparison between our proposals and PSEG LI's, see Exhibit____(SCSP-3).

Q. How does HAR enrollment compare to HEAP enrollment?

A. According to the Office of Temporary and Disability Assistance or OTDA, the data outlining the number or level of HEAP benefits authorized so far in January 2015 for Nassau and Suffolk Counties was 61,475, see Exhibit___(SCSP-5), while the average HAR enrollment in 2014 was 15,300. It, therefore, appears that PSEG LI has only reached out to only one-fourth of its low income customers. Please refer to our comparison in Exhibit___(SCSP-4).

Q. What types of outreach does PSEG LI do to inform the public of its Low Income Programs?

A. PSEG LI, in response to IR DPS-CSP-0431, stated that REAP is promoted at various events which include home shows, street fairs, libraries, and other community venues. In addition, PSEG LI distributes REAP postcards to customers in zip codes with a higher low income population. In 2014, it attended 109 outreach events for the REAP program. This shows that although PSEG LI has an extensive low income outreach program currently in place, its focus on these outreach efforts is more effective with respect to the REAP program than the HAR program.

Q. What are Staff's recommendations regarding PSEG LI's low income outreach initiatives?

A. To correct under-enrollment in the HAR Program, we recommend adjusting PSEG LI's outreach efforts to promote its HAR program to its low income customers to mirror what it is already accomplishing with its REAP program. To accomplish this effort, PSEG LI should reallocate part of its outreach funding to promote the HAR program. We recommend that the Company partner with the Nassau and Suffolk Counties' Department of Social Services and the New York City Human Resources Administration as well as the Department of Veterans Affairs Administration to be able to reach out to low income households who may qualify in the Company's Low Income Program. Through partnerships with these agencies, PSEG LI can boost enrollment in HAR by matching customer records. PSEG LI should take on more grassroots outreach efforts to reach out to communities with low income residents and to be more visible in these communities. As in the REAP outreach, the Company should also mail HAR postcards to raise awareness for customers to learn about and understand the program.

Q. Should there be a cap of 50,000 customers who can be enrolled on the HAR Program?

A. No. Low income households in Long Island could be as high as or exceed 61,475. Therefore, it is not reasonable to create a threshold that would potentially deny a low income customer who may be eligible for HAR. It is our recommendation that the cap of 50,000 should be removed to accommodate all eligible low income customers. Additionally, removing the cap will align PSEG LI with the other utilities in New York State where a cap does not exist.

Customer Removal Charge

Q. What new customer charge does PSEG LI propose?

A. PSEG LI proposes to introduce a new Customer

Service Charge called a "Removal Charge." The charge is a $160 fee assessed when PSEG LI is required to disconnect a customer for a second time due to that customer's tampering with LIPA's facilities or equipment. This fee is assessed to customers who energize their electrical service after PSEG LI disconnects service.

Q. What is PSEG LI's justification for the Removal Charge?

A. PSEG LI believes that this proposed charge is a way to deter the customers from tampering with meters and electric service, as well as, reduce the overall theft of electric service.

Q. Does Staff support the Removal Charge?

A. No. LIPA's tariff already includes investigation fees when theft of service is found. Furthermore, PSEG LI and/or LIPA have the option to go to litigation and prosecute these cases to the full extent of the law.

Q. Does this conclude your testimony?

A. Yes, at this time.

JUDGE PHILLIPS: Next we have a request from?

MR. RAGONETTI: This is Nassau County. I am David Ragonetti. Thank you, Your Honor. This will be quick. Please let the record show that I have an affidavit here of George Maragos for the Prepared Testimony of George Maragos. The document consists of six pages plus a title page, no exhibits. May I approach.

JUDGE VAN ORT: Yes.

JUDGE PHILLIPS: Yes.

MR. RAGONETTI: (Handing) Thank you.

JUDGE PHILLIPS: The affidavit of Honorable George Maragos, County Comptroller, serving as the basis for his testimony has been marked as 119, Exhibit 119. On that basis, we ask the court reporter to copy into the record as though given orally his six pages plus title page of testimony that was submitted in this matter. Thank you.

Ragonetti, David

From: Ragonetti, David
Sent: Thursday, June 04, 2015 1:06 PM
To: Van Ort, David (DPS); Phillips, Michelle (DPS); dps.sm.Secretary
Cc: ServiceList@nrg.com; Sanghvi, Alpa; angela.schorr@directenergy.com; afiore@dep.nyc.gov; bmiller@cullenanddykman.com; christopher@ippny.org; Christopher.Wentlent@constellation.com; Leimone, Christopher; ckudder@optonline.com; Ragonetti, David; Dfranco@Cullenanddykman.com; county.attorney@suffolkcountyny.gov; ddaley@ibew1049.com; Hogan, Erin (DOS); gconboy@caithnessenergy.com; Service.List@nrg.com; Collar, Gregg (DOS); Mazza, Guy (DPS); hjr@readlaniado.com; jeffrey.levine@gdfsuezna.com; jeffrey.greenblatt@pseg.com; Service.List@nrg.com; comptroller@suffolkcountyny.gov; john.kennedy@suffolkcountyny.gov; Favreau, John (DPS); joe.schroeder@suffolkcountyny.gov; jbell@lipower.org; kterry@justenergy.com; KELLI.JOSEPH@nrg.com; KMaloney@cullenanddykman.com; krb@readlaniado.com; kp@readlaniado.com; matthew.weissman@pseg.com; Zimmerman, Michael (DOS); mpiasecki@couchwhite.com; schimelm@assembly.state.ny.us; Forst, Nicholas (DPS); peter.fuller@nrgenergy.com; rachel@mecny.com; Caputo, Regina (DPS); rcalica@rcblaw.com; robert.grassi@pseg.com; rloughney@couchwhite.com; JGoodman@CouchWhite.com; sml@readlaniado.com; swilt@nrdc.org; sklimberg@rmfpc.com; wemples@conedcss.com; thomas.bjurlof@outlook.com; Ufogel@aol.com; Vstrauss@aea.us.org; Vaughn.McKoy@pseg.com; Brindley, Wayne (DPS); WCMillerJr@ClearviewGroup.net; Leimone, Christopher; Sanghvi, Alpa
Subject: Matter No. 15-00262 - County of Nassau - Rebuttal Testimony of County Comptroller George Maragos
Attachments: Comptroller Rebuttal Testmony_06_04_15 FINAL.pdf

The Hons.,

Please find enclosed rebuttal testimony filing by Hon. George Maragos, County Comptroller, on behalf of the County of Nassau in the above-referenced matter. Please contact me with any questions or to discuss. Thank you.

Regards,

David A. Ragonetti
Deputy County Attorney
Office of the Nassau County Attorney
T: 516-571-3931
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dragonetti@nassaucountyny.gov

Sempre Avanti

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

MATTER NUMBER 15-00262

In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC.

Prepared testimony of
Hon. George Maragos, County Comptroller
Nassau County, New York June 4, 2015

Q. Please state your name and business address.

A. My name is George Maragos. My business address is 240 Old Country Road, Suite 210, Mineola, New York 11501.

Q. Mr. Maragos, do you represent any entity with an interest in these proceedings and, if so, whom do you represent?

A. Yes. I am the elected Nassau County Comptroller, serving in this capacity since 2010. In my capacity as the Nassau County Comptroller, pursuant to the authority granted by that Office, I hereby submit my testimony on behalf of all of the interested ratepayers of Nassau County.

Q. Do you have professional experience relevant to the subject matter of this proceeding?

A. I have over 35 years of senior management experience with leading organizations in Banking, Consulting and Information Systems. I was president of my own technology firm for 20 years. Prior to that, I served as Vice President of Citicorp and the Director of Telecommunications for Treasury Systems. Prior to Citibank, I was a Vice President at Chase Manhattan Bank, holding various senior systems management positions responsible for planning and implementing the global electronic financial systems and the telecommunications networks that supported the global banking network. Earlier in my career I was also a consultant with Booz Allen and Hamilton and with Bell-Northern Research as manager of Communications Planning. Academically, I hold a Master's in Business Administration in Finance (1983) from Pace University in New York City, and a Bachelor of Electrical Engineering Degree (1973) from McGill University in Montreal.

Q. **Have you previously testified in proceedings before the New York Department of Public Service ("DPS")?**

A. Yes. I provided statements on March 4, 2015 at the DPS Hearing in Mineola concerning the PSEG Long Island ("PSEG") and Long Island Power Authority ("LIPA") Summary of 2016-2018 Three Year Rate Plan ("Plan").

Q. **To the best of your knowledge, is there any portion of your March 4th testimony that LIPA, PSEG or any other Party to the Matter have failed to address?**

A. Yes, they have not responded to any of our issues. LIPA and PSEG has not responded to requests to provide documented evidence of initiatives taken; to improve productivity and reduce costs through technological innovations and better management practices, or to align expenditures with those of well-run comparable utilities with respect to overhead cost ratios, direct cost ratios, maintenance costs ratios, capital investment ratios and other management performance measures. PSEG appears from the Plan to continue to perpetuate the old inefficient management practices and operating philosophies of LIPA; and PSEG continues to rely on low-tech improvements such as tree-trimming and the installation of environment-destroying chemically-treated 80 foot poles.

Q. Have you contacted LIPA, PSEG or any other Party to the Matter since March 4th in attempts to address these concerns?

A. Yes.

Q. What was the nature of that contact?

A. On April 16, 2015, I met with Caisy L. Meyers, District Manager of External Affairs for PSEG and Robert G. Grassi, Esq., Associate General Regulatory Counsel for PSEG at the Comptroller’s Office in Mineola to discuss my testimony on March 4th as well as to express my concerns with the proposed rate increase.

Q. What was discussed at that meeting?

A. I reiterated my concerns regarding cost-reduction and management practices outlined in my March 4th testimony. Mr. Grassi and Ms. Meyers represented that PSEG had, in fact, implemented numerous measures to reduce costs and make management more efficient. Mr. Grassi and Ms. Meyers indicated to me that they would provide my Office with documentation to support these initiatives and their budgetary impact.

Q. Was your Office provided this documentation?

A. No.

Q. Did your Office perform any further analysis since your March 4th testimony?

A. Yes.

Q. **What additional analysis did your Office perform?**

A. First, our Office reviewed a document which was filed on the NYS Department of Public Service Matter Document and Management System on May 1, 2015, entitled "Capital Budget Panel (Exhibit ____ CBP-3)". This document sets forth a budgeted line item of $38.162 million for long-term ERP, a capital budget expense of LIPA. However, we believe that this ERP capital budget expense should be the responsibility of PSEG under its operating agreement with LIPA, to provide expertise, management tools and other solutions readily available to PSEG to provide best-in-class service. PSEG NJ should have such an ERP tool-set which should have been carried over to PSEG with minimal cost under the Operating Agreement.

Second, the Plan sets forth a Management Fee line item, under LIPA Operating Expenses, in the amount of $73.4 million, which exceeds that of the prior year by $28.0 million. We believe that the nearly $74 million in Management Fees may be miscalculated and based on productivity incentives which have not been earned and may include up to $20 million in duplicative senior management expenses.

Third, our Office has also reviewed the LIPA Comprehensive Annual Financial Report ending December 31, 2014 and 2013 ("CAFR"). Pursuant to Note 5 of the CAFR, Commodity Derivatives were listed with a positive fair market value of $19.296 million, representing a gain of $62.86 million over December 31, 2013. This translates into an average gain of $53.8 million per year during the immediately preceding two years. However, it appears that no hedging benefits are being utilized in the Plan. Accordingly, rather than accumulating this off budget gain, we believe that about $50 million should be utilized to help offset the proposed rate increase.

Fourth, we believe that reasonable productivity improvements over the prior LIPA management, which align operating ratios to well-run utilities, should have translated into at least

5% savings on the $1.9 billion delivery charge Budget or $95 million in reduced budgetary benefit.

Q. In summary, what is your recommendation concerning the PSEG proposed 2016-2018 three-year plan and rate increase?

A. As a result of the analysis conducted by my Office, which I have summarized here, it is my recommendation that the potential cost reduction measures and management efficiencies will result in $215 million in expense reductions and revenue gains as follows: (1) $38.2 million in ERP capital expenses, (2) $28 million in Management Fee increase, (3) $53.8 million in hedging gains and (4) $95 million in productivity improvements.

When combined with the cost reduction opportunities as determined by the Department of Public Service of $173.2 million, PSEG should not only be prevented from raising rates on residents by $221 million or almost 4% annually over three years (as a function of delivery-only charges), but rather, should be able to maintain a zero increase in rates and potentially reduce rates if it takes full advantage of available opportunities as listed above.

Q. Does this conclude your testimony?

A. Yes it does.

JUDGE PHILLIPS: Let's go off the record.

(Whereupon, an off-the-record discussion was held.)

JUDGE PHILLIPS: We will start with PSEG, go to New York City, then go to LIPA and I will have you identify what we are doing. I would like to ask if counsel for PSEG could please describe the affidavits and testimony that will be entered next.

MR. WEISSMAN: Certainly, Your Honor. The first affidavit I have is front of me is on behalf of Mr. David Lyons and Martin Shames. It is the Affidavit of Shared and Business Services Panel which was testimony filed on January 30th. It consists of 24 pages and two exhibits. Those exhibits are SSP-1, a two-page document identified as Exhibit 65 and SSP-2, a single page exhibit which is Exhibit 66. I would offer that testimony into the record via affidavit (handing).

JUDGE PHILLIPS: The affidavit of the Shared and Business Services Panel have been marked for identification as Exhibit 120. On that basis, we request that their testimony filed on January 30, 2015 as been previously described be copied into the record as though orally given.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-____________

DIRECT PRE-FILED TESTIMONY
OF
THE SHARED AND BUSINESS SERVICES PANEL

Date: January 30, 2015

TABLE OF CONTENTS

I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Shared And Business Services Panel (the "Panel").

A. We are David C. Lyons and Martin Shames.

Q. Mr. Lyons, please state your name and business address.

A. My name is David C. Lyons. I am employed by PSEG Services Corporation ("PSEG Services"). My business address is 80 Park Plaza, Newark, New Jersey 07801.

Q. In what capacity are you employed by PSEG Services?

A. I am employed as Director Corporate Integration with the responsibility of overseeing the integration of PSEG Long Island ("PSEG LI")'s back-office operations with Public Service Enterprise Group, Inc.'s ("PSEG") corporate functions.

Q. Please summarize your educational background and professional experience.

A. I have over 20 years of experience in IT and senior level management at PSEG. Previously, I served as director of treasury operations at PSEG Services, with the responsibility for PSEG's headquarters facilities, corporate real estate, and survey and mapping. Since joining PSEG in 1981, I have held a variety of positions, including project director of PSEG Services as a direct report to the President and Chief Operating Officer of PSEG Services. In this position, I was responsible for the implementation of a PSEG-wide shared service business. This included the development of a business services catalogue, pricing, and sales totaling $400 million with PSEG's operating companies. I have also served PSEG as the director of medical services, director of workforce planning and development, director IT business solutions, director e-business strategy, and general manager IT Operations and Client Services.

I have a Bachelor of Science degree in electrical engineering technology from New Jersey Institute of Technology, and an Executive Master of Business Administration (EMBA) from New York University, Stern School of Business.

Q. Mr. Shames, please state your name and business address.

A. My name is Martin Shames. My business address is 80 Park Plaza, T-20, Newark, NJ 07102.

Q. By whom are you employed and in what capacity?

A. I am employed as the Director of Finance for PSEG Services. In that capacity, I have responsibility for overseeing all financial functions of PSEG Services including the budgeting, assignment and billing of its costs of providing services to affiliates.

Q. Please describe your educational and professional background.

A. I possess a Bachelor's degree in Mathematics from Cornell University and a Masters of Business Administration in Finance from Columbia University. I have 25 years of work experience in finance, management and consulting, with 20 years working in corporate and shared services.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of the Panel's direct testimony?

A. The purpose of our testimony is to support the costs of certain business services included in the three-year Rate Plan being submitted by PSEG LI on behalf of the Long Island Lighting Company d/b/a/ LIPA ("LIPA") for the calendar years ("CY")

2016 through 2018, and to explain the shared services framework that is used to deliver some of those business services and other services to LIPA. We will discuss the types of costs incurred for business services, the manner in which budgets have been developed for these services for the period CY 2016-2018, and the projected costs to be incurred. We will describe (i) the manner in which costs are incurred by PSEG LI from certain of its affiliates to enable it to provide services to LIPA and its customers under the Amended and Restated Operation Services Agreement ("OSA") between PSEG LI and LIPA, (ii) the cost assignment and allocation policies and procedures that govern the manner in which the costs of shared services are assigned to PSEG LI for subsequent passthrough to LIPA, and (iii) the policies and procedures followed by PSEG LI to ensure both that the costs incurred to provide service to LIPA are reasonable and accurate and that any differences between budgeted and actual costs incurred for those services are transparent.

Q. Do you sponsor any exhibits as part of your testimony?

A. Yes. We sponsor the following exhibits which were prepared or compiled under our supervision and direction:

(i) Exhibit __ (SSP-1) sets forth a breakdown of the budgeted expenses for PSEG LI's business services by function for CYs 2015, 2016, 2017 and 2018; and

(ii) Exhibit __ (SSP-2) provides detail concerning PSEG LI's 2015 budget for shared and business services.

III. OVERVIEW OF BUSINESS SERVICES AND THE SHARED SERVICES FRAMEWORK

Q. What are the business services that are provided to and utilized by PSEG LI in providing service to LIPA?

A. Business services are the administrative and general functions that support the transmission and distribution and customer service areas of PSEG LI. These services consist of the following;

(i) information technology ("IT") management,
(ii) facilities management,
(iii) finance and accounting,
(iv) legal,
(v) human resources,
(vi) procurement,
(vii) communications,
(viii) public affairs,
(ix) internal audit,
(x) security, and
(xi) business performance excellence.

Some of these services are provided through PSEG's shared services framework while others are housed in the Office of the President of PSEG LI. The services are managed by the Vice President for Business Services.

Q. How are business services provided by PSEG LI?

A. Each of the business services functions is managed by personnel who are fully dedicated to PSEG LI and assigned the responsibility to provide those services as efficiently as possible. The majority of the business services functions are performed by PSEG LI employees. These employees, as needed, obtain some assistance in providing those business services from affiliated companies. The majority of the support for PSEG LI shared business services functions is provided by PSEG Services. Generally speaking, PSEG Services employs the individuals who provide business services to PSEG LI and obtains the outside resources necessary to provide those services on behalf of PSEG LI. Most of the labor and non-labor costs assigned by PSEG Services to PSEG LI are for internal labor and outside services. The costs incurred for business services are passed through to PSEG LI in accordance with PSEG's enterprise-wide cost allocation policies and procedures. Direct assignment is the primary way that PSEG Services assigns the costs of shared services to PSEG LI.

Q. Please describe the corporate structure of PSEG LI and its parent and affiliates.

A. PSEG LI is a wholly owned subsidiary of PSEG, a publicly traded utility holding company. Other direct or indirect subsidiaries of PSEG that provide services to LIPA are:

(i) Public Service Electric and Gas Company ("PSE&G"), which is a public utility that provides electric and gas distribution services at retail to a significant portion of consumers of those services in New Jersey, and is among the largest utilities in the United States;

(ii) PSEG Services, which provides management, administrative and general services to the affiliates and subsidiaries of PSEG at cost; and

(iii) PSEG Energy Resources & Trade LLC, which is a subsidiary of PSEG Power LLC – another subsidiary of PSEG, that provides services to LIPA under separate Fuel Management and Power Supply Management agreements.

Q. Does PSEG LI utilize the shared services framework to provide customer and/or transmission and distribution services to LIPA?

A. Yes. PSE&G provides a modest amount of services to PSEG LI that are used by PSEG LI to provide transmission and distribution services for LIPA. The costs of these services are forecast to total approximately $1 million in each of CYs 2016, 2017 and 2018.

Q. Does the OSA between PSEG LI and LIPA have provisions that govern the passthrough of the costs of services obtained by PSEG LI?

A. Yes. As a general matter, the OSA requires that services provided by affiliates must be provided at cost without any mark-up or profit. However, the OSA stipulates that there may be instances in which an affiliate of PSEG LI may provide services relating to the Transmission and Distribution ("T&D") system that include a mark-up or profit if approved by LIPA. The budgeted costs for shared services reflected in the three-year Rate Plan are projected to be provided at cost regardless of whether they are incurred from PSE&G or PSEG Services.

Q. How do PSEG LI's affiliates charge costs to PSEG LI for shared services?

A. When a service is provided by PSEG Services solely to PSEG LI, PSEG Services's cost of providing that service are directly assigned to PSEG LI. When a service is performed for multiple affiliates, charges are aggregated in cost pools and assigned to all affiliates that benefit from the service using approved assignment methodologies. Bill pools/cost pools, which are generally established in accordance with the cost causation principle, have been developed to assign the different types of costs assessed by PSEG Services. When it is not appropriate to use a direct or cost causation-based code, then a general allocator is used. The general allocator is based on a three point formula that reflects an equal weighting of employee headcount, controllable operation and maintenance expenses and net fixed assets.

Applicable federal and state regulatory cross-subsidization policies require that when PSE&G provides a service to an affiliate, PSE&G must charge for those services at rates equal to the greater of cost or market. We have determined that each of these services is being provided at cost to PSEG LI. Records are maintained to ensure that the appropriate measures of cost and market are used for these services.

Q. Please describe how assets leased by PSEG Services are charged to PSEG LI.

A. PSEG Services leases a number of shared assets that are used to provide services to affiliates. These are primarily shared office facilities and information technology equipment and software. When leased assets are used by PSEG Services, the lease rentals are charged to affiliates at cost using the cost assignment methodology described previously.

Q. Has PSEG implemented an established set of cost allocation policies and practices?

A. Yes. An established set of cost allocation policies and procedures have been implemented and are in effect for all PSEG companies. As we mentioned previously, these policies and procedures provide for a cost causative assignment process that is consistently applied throughout the PSEG organization. This process emphasizes the importance of using direct assignment as a first preference and is generally designed to use a cost assignment method that bears the closest possible relationship to cost causation. At the same time, when there is no readily determinable cost causative basis available to allocate costs, there is a general allocator that is used to allocate costs in a reasonable and transparent manner.

Q. IsPSEG LI's ability to obtain services from PSEG Services and other affiliates beneficial to LIPA and its customers?

A. Yes. The ability to obtain services under a shared services framework benefits all of PSEG's subsidiaries including PSEG LI. Specifically, the shared services model enables PSEG LI and PSEG's other operating companies to (i) attain the benefits of scope and scale available from the provision of centralized services to a number of operating entities in a manner that ensures that no operating entity cross-subsidizes another, (ii) improve service quality through enhanced job differentiation and specialization that results from the provision of services on a centralized basis to a number of operating entities, (iii) maintain and improve the reliability and consistency of services within the organization, and (iv) implement enhanced controls and uniformity of methods and practices throughout the organization. The shared services that PSEG LI obtains and provides to LIPA and its customers are the same types of services that PSE&G requires to provide service in New Jersey. The use of a shared service framework to provide services in each jurisdiction is beneficial to all customers.

Q. How does PSEG LI monitor and control the costs it incurs for services obtained from PSEG Services and other affiliates?

A. The managers at PSEG LI responsible for individual functions have the responsibility to (i) develop budgets designed to enable PSEG LI to meet its responsibilities to LIPA under the OSA, (ii) monitor performance against those budgets, and (iii) review monthly bills from PSEG Services and other affiliates to ensure that the costs assessed to PSEG LI are reasonable, appropriate and in line with budgets. PSEG LI is incented under the OSA to attain cost management goals in order to receive incentive compensation. Specifically, under Appendix 9 of the OSA, PSEG LI must achieve spending levels equal to or less than 102% of the annual operating and capital budgets approved by LIPA in order to be eligible for the total incentive compensation available under the OSA.

Q. What actions do PSEG LI, PSEG Services and other affiliates take to control service company costs?

A. As part of their normal management practices, PSEG LI, PSEG Services and all other PSEG affiliates engage in continuous efforts to control costs and achieve efficiencies. For example, PSEG Services' costs basically consist of (i) internal labor and (ii) outside services associated with operating and capital expenditures. With respect to internal labor costs, PSEG's human resources organization controls these costs by monitoring the overall compensation package of PSEG, comparing that package to those provided by similarly situated companies, and conducting regular reviews to determine opportunities to control benefits costs. Benchmarking ensures that overall compensation costs remain consistent with labor market conditions. With respect to outside services and employee expenses, PSEG LI and its affiliates endeavor to control those costs by conducting competitive bidding among third-party suppliers and/or negotiating discounts through a centralized procurement area.

Q. How does PSEG Services attempt to benchmark the costs of various services it provides against other third-party providers?

A. PSEG Services participates in a variety of benchmark studies, sponsored both by PSEG itself, commercial providers and industry trade groups. Studies typically look at one or more functional areas and provide insights into costs and staffing levels among a group of comparison companies that are generally of similar size and scope to PSEG.

Q. How does PSEG ensure that its cost allocation policies and procedures are being applied on a consistent basis throughout the organization?

A. PSEG maintains and revises annually a detailed cost accounting manual for the entire organization. All management and bargaining unit employees are required to participate annually in training which provides guidelines regarding transactions between affiliate companies. In addition, as we have described, monthly charges incurred by PSEG LI are reviewed to ensure that they are consistent with budgets and reflective of the work being performed.

IV. <u>BUSINESS SERVICES BUDGETED COSTS</u>

Q. What are the total budgets for business services for CY 2016, 2017 and 2018?

A. The total budgets for business services for CY 2016, 2017 and 2018 are set forth on Exhibit __ (SSP-1) as follows:

2016	2017	2018
$138,899,989	$152,303,206	$161,160,699

Q. Please describe Exhibit __ (SSP-1).

A. Exhibit __ (SSP-1) consists of 2 pages and provides a breakdown of the budgeted costs for business services provided by PSEG LI to LIPA for CY 2015, 2016, 2017 and 2018.

Q. How were the budgets set forth on Exhibit __ (SSP-1) determined?

A. The budget process is described more fully in the testimony of the Budget Panel. The budget process described therein was followed in determining the budget for business services. However, the business services organization also faced certain unique circumstances and constraints in arriving at its budget amounts for CY 2016, CY 2017 and CY 2018.

Q. Please describe those circumstances and constraints.

A. The OSA took effect on January 1, 2014. Because the OSA required an operating model for LIPA that had not existed previously, PSEG LI was required to design and implement a new organization to provide service to LIPA and its customers. Prior to 2014, many, but not all, of the functions performed by PSEG LI were provided by affiliates of National Grid USA Inc. (“National Grid”). Other functions were performed by LIPA itself. To effectuate a transition, we entered into a Transition Services Agreement (“TSA”) with National Grid that allowed PSEG LI to obtain financial data and various services from National Grid during the transition. The costs associated with this agreement, as well as the costs of transferring various data from National Grid’s financial and operational platforms to PSEG’s SAP and related systems are reflected in our 2014 actual results as well as in our 2015 budget and comprise approximately $25 million of costs that are budgeted for 2015.

Q. Do you expect to complete the transition from National Grid to PSEG LI in 2015?

A. Yes. As a result of completing the transition we project that the cost of operating financial systems will be reduced from approximately $10.7 million in 2015 to between $6.1 to $6.4 million in the 2016-2018 period.

Q. Is the transition from National Grid to PSEG LI a complex undertaking?

A. Yes. It is both complex and unique. As we stated previously, National Grid did not perform all of the functions for LIPA that PSEG LI now performs for LIPA under the OSA. Thus, in the first instance, it was necessary to determine the differences, that is to identify the functions and systems that PSEG LI would need to provide that National Grid did not provide for LIPA, and implement a process to provide those functions. In addition, and more significantly, the transition from National Grid was not like a typical acquisition or merger where the acquiring entity has access to all of the existing systems and data of the acquired entity. Instead, we were required to negotiate and implement the TSA with National Grid that allowed PSEG LI to transition data to its own platform. To illustrate the complexity of the transition, in the IT area, we conducted a review of approximately 600 information systems and applications that are used by PSEG's New Jersey electric distribution utility to provide electric utility service in New Jersey. We ultimately determined that approximately 550 of these systems and applications should be used by PSEG LI, and thus we undertook to enable PSEG LI to obtain access to these systems from the third-party vendors who provide and support them. In some cases, the licenses and other agreements that govern access to the systems and applications were assignable and in some cases they were not. In cases where they were not assignable, we negotiated with the vendors to obtain new licenses and agreements.

Q. Do the actual expenses for business services incurred in 2014 provide a reasonable starting point for determining the costs of business services that are projected to be incurred during the CY 2016 – CY 2018 period?

A. There are a number of reasons why PSEG LI's 2014 actual costs of providing business services do not provide a useful starting point for evaluating the costs that we project PSEG LI will incur during the CY 2016 – CY 2018 period. First, as we have already mentioned, during 2014, PSEG LI incurred significant costs to obtain financial information from National Grid and transition from National Grid's financial and operations platforms to our SAP system. These costs totaled approximately $61 million in 2014. These costs will not recur as costs from National Grid in CY 2016 – 2018.

Second, as we have also mentioned, in 2014 PSEG LI was required to design and implement a new organization to provide LIPA with a variety of services that were not provided by its previous system operator. This organization initially was designed using similar utility organizations as benchmarks to determine the resources that would be needed to meet the requirements of the OSA. Once we gained experience operating under the OSA, we were better able to refine our projection of the activities that we need to perform under the OSA and the costs of those activities. Our more refined projections are reflected in the 2015 budget. The 2015 budget thus provides a far better starting point for determining projected costs for the CY 2016 – CY 2018 period than actual 2014 results. A breakdown of the 2015 business services budget is attached hereto as Exhibit __ (SSP-2).

Q. Please describe the major components of the business services budgets for CY 2015, CY 2016, CY 2017 and CY 2018.

A. The major components of the business services budgets are the budgets for IT, finance and accounting, facilities management and legal expenses. These functions represent approximately 75% to 80% of the total business services budget. None of the other individual components of the business services budget account for more than 5% of the total shared services budget.

Q. How were the business services budgets for CY 2016 through CY 2018 determined?

A. The starting point for the business services budgets for CY 2016 through CY 2018 is the 2015 business services budget. The business services budgets for CY 2016 through CY 2018 reflect projected changes in costs for outside goods and services that are based either on estimates provided by our third-party advisors or that are contractually required. An example of the former type of projection is our estimate that outside insurance costs will increase by 5% per year. This projected increase is based on estimates developed with our insurance broker who participates actively in the markets for various types of insurance. In addition, where, for example, we have facilities leases that contain contractually determined increases, we have included these increases in our budget. All remaining business services budget items reflect, in the aggregate, annual inflation increases of 2.9% for CY 2016, 2.3% for CY 2017 and 2.3% for CY 2018.

Q. Please describe the expenses included in the budget for information technologies.

A. Approximately 80% to 85% of the IT budget for CYs 2016, 2017 and 2018 represents the projected cost of purchasing applications and services from third-party vendors. A portion of these costs will also be incurred to utilize PSEG's SAP platform for all general ledger transactions in lieu of relying on data provided by National Grid under the TSA. This function is known as Enterprise Resource Planning ("ERP"). The budgeted operation and maintenance expenses for the IT area are set forth on Exhibit __ (SSP-1).

Q. In addition to the management of the ERP system, what are the IT functions that require PSEG LI to incur operating and maintenance costs?

A. The IT functions can be broken down as follows:

(1) Critical Network Infrastructure ("CNI") – CNI and its supporting systems provide the critical day-to-day monitoring and support for LIPA's electric grid. This area comprises 19 applications and/or systems that include the Supervisory Control and Data Acquisition ("SCADA") system, the outage management system, the energy management system and the customer accounting system.

(2) General Corporate Support Systems – (Software and Applications) – These systems represent the corporate support systems other than the ERP system that are used for back office functions, to support our mobile workforce, and for security. These non-ERP systems comprise more than 200 distinct applications that are used by more than 2,000 employees in varying ways as part of their daily work functions.

(3) Communications – The communications function ensures land-based connectivity to support the CNI, the activities of our mobile workforce, and our ongoing ability to operate LIPA's facilities. The communications infrastructure comprises telephones, cellular communication devices, VHF radios and associated antennas and towers. Approximately 3,000 communication assets are supported by our IT organization.

(4) Networks – Networks provide for the wired and wireless connectivity of systems to support CNI and corporate requirements. Network services consist of operation and maintenance of the switches, routers, hubs, firewalls and appliances necessary to maintain various networks.

(5) Hardware – Hardware services consist of the operation and maintenance of servers, workstations, mainframes, storage facilities, desktops, laptops, portable handheld communication devices, personal delivery assistant devices and video management equipment. Our hardware assets consist of approximately 550 servers and 2,750 other devices.

(6) Security – Security-related IT services are required to enable PSEG LI to operate cameras, workforce badges, perimeter detection devices, card readers, security panels, door locks and gates and intrusion detection devices.

(7) Other IT Infrastructure – In addition to the other equipment, the IT area also operates and maintains network cabling, raceways, racks, air conditioning units and power generation equipment.

Q. How are IT projects managed by PSEG LI?

A. PSEG LI utilizes internal labor and outside contractor resources to manage its IT applications and resources. For CY 2016, CY 2017 and CY 2018, the budgets are based on an internal staff of 47 full time equivalent employees and 31 full time equivalent contractors. PSEG LI utilizes a process-based methodology to commence and manage IT projects. The process is based on a well-known, industry-standard model known as the Capability Maturity Model Integrated ("CMMI"). CMMI was developed at Carnegie Mellon University over 25 years ago. The CMMI process is monitored by our internal IT organization through a quality assurance function and is subject to review by both our internal audit department and in an annual audit by an external auditing firm.

Q. What are the major expenditures in the budget for finance and accounting?

A. The finance and accounting budgets reflect 57 full time equivalent employees to perform all of the finance and accounting functions of PSEG LI, including accounting, budgeting, planning, rate administration and financial support for regulatory filings including rate proceedings, and treasury and business center functions. The non-labor budget primarily represents the cost of insurance that PSEG LI procures in accordance with the OSA, and other miscellaneous expenses such as bank fees. The budgeted costs for finance and accounting are set forth on Exhibit __ (SSP-1).

Q. What types of insurance does PSEG LI procure?

A. As required by the OSA, PSEG LI procures property, liability and nuclear outage insurance for LIPA. The OSA also requires PSEG LI to provide workers compensation, fiduciary and travel accident insurance for PSEG LI. Property, liability and workers compensation insurance represent the largest elements of these costs. The insurance requirements are addressed in Appendix 11 of the OSA.

Q. How does PSEG LI procure this insurance?

A. As insurance coverages approach expiration, LIPA determines its insurance requirements and communicates those needs to PSEG LI. PSEG LI utilizes an outside broker to assist in evaluating competitive options and procuring packages of insurance that meet LIPA's needs. LIPA has the final say over the coverages that PSEG LI obtains.

Q. Do you project that the cost of LIPA's insurance will increase during CY 2016, CY 2017 and CY 2018?

A. Yes. Based on information received from our broker we project that insurance costs will increase by 5% each year.

Q. What are the major expenditures in the budget for facilities management?

A. The largest component of this budget are expenses associated with leasing various facilities in LIPA's service territory. These facilities include nine operating centers and one call center that are leased from National Grid. LIPA also leases ten other facilities that are used for a various operating and administrative purposes. Generally speaking, these facilities were the same facilities used by LIPA to provide service under its previous management arrangement with National Grid. The costs of these facilities comprise 92% of the facilities costs reflected in the 2016-2018 facilities management budgets. The costs associated with facilities management are set forth on Exhibit __ (SSP-1). The costs reflected in the budgets include base rent, operating costs and property taxes.

Q. Were the terms of the various facilities leases negotiated at arm's length?

A. Yes. PSEG LI/LIPA utilized the services of a third-party broker to determine the fair market values of the base rent paid under the facilities leases. Operating costs of the facilities that are passed through under the various leases were determined based on a five-year average of actual operating costs during the 2008-2012 period. Property taxes are the amounts assessed by the taxing authorities.

Q. Did PSEG LI investigate whether to move to facilities at locations other than those LIPA had previously utilized?

A. Yes. However, PSEG LI determined that the costs of moving to and operating from alternative facilities outweighed the benefits. In considering the location of existing facilities, PSEG LI and LIPA concluded that LIPA's existing facilities were preferable to available alternatives.

Q. What are the major expenditures in the budget for legal services?

A. The major expenditures for legal services are (i) the projected costs of maintaining an in-house legal department that consists of 29 full-time equivalent employees, including 12 attorneys, 9 claims representatives, 2 paralegals, 3 administrative assistants and 2 records managers, (ii) the costs of shared legal services employees from PSEG Services to assist dedicated PSEG LI legal staff, (iii) the costs of outside counsel both to supplement our internal legal resources during peak periods and provide specialized expertise, and (iv) the costs of claims and records management. Budgeted legal expenditures are set forth on Exhibit __ (SSP-1).

Q. When does PSEG LI use outside counsel?

A. Outside counsel are typically used for (i) significant commercial and tort litigation; (ii) complex rate and regulatory matters; (iii) environmental matters; (iv) large commercial transactions; and (v) certain labor and compliance matters. Thus, for example, the CY 2017 and CY 2018 legal expense budget includes outside counsel expense to support another base delivery rate filing during the last year of the three-year Rate Plan. Outside counsel are also employed to handle matters during peak periods when the expected future level of demand for legal services does not support hiring of additional in-house resources. Outside counsel are generally selected through a competitive process that considers both the outside counsel's level of expertise and projected cost of representation.

Q. What is the basis of PSEG LI's projected costs of claims for the CY 2016 - CY 2018 period?

A. The projected claims costs for the CY 2016 – CY 2018 period are generally consistent with recent claims experience.

Q. Please describe business performance excellence ("BPE").

A. BPE comprises two major functions. The first is Performance Analysis and Reporting ("PA&R"), which is responsible for the end-to-end processes associated with the performance metrics established under the OSA. These metrics are used to determine whether PSEG LI is paid incentive compensation under the OSA. PA&R is responsible for determining and reporting the monthly results of PSEG LI under the metrics to LIPA and the New York State Department of Public Service ("DPS"). PA&R also provides monitoring and reporting of various change initiatives of PSEG

LI and the linkage of those initiatives to various performance metrics. PSEG LI's performance under the OSA's performance metrics is discussed in the testimony of the Metrics and Safety panel.

The second function in BPE is to execute the Continuous Improvement/Operating Excellence Model. This team is responsible for process improvements and the formal documentation of technical manuals and processes. For example, this team has assisted in developing, implementing and documenting processes reflected in emergency response plans and logistics plans for storm response that were submitted to the DPS. This team is also updating the Contract Administration Manual and other critical processes.

The budget for BPE includes expenses for internal labor, costs for memberships in benchmarking peer panels, expenses for outside consultants to assist in process improvements, and miscellaneous additional expenses. The budgeted costs for BPE are set forth on Exhibit __ (SSP-1).

Q. Please describe the procurement function and explain how PSEG LI manages procurement.

A. The PSEG LI procurement organization supports the ongoing material and service requirements of PSEG LI. The procurement area works to maintain an assurance of supply and mitigate the risk of supply shortfalls by following a rigorous supplier selection and evaluation process. The procurement function primarily utilizes internal labor that is fully dedicated to PSEG LI to provide this function. Resources from PSEG Services are also used to assist in procurement. The PSEG LI procurement area looks for opportunities to reduce costs, streamline processes and standardize specifications where possible in an effort to operate with optimal efficiency. The PSEG LI procurement function is fully integrated with the PSEG-wide procurement organization and is therefore able to benefit from the synergies that arise from PSEG-wide procurement, including access to a broad supply base and the ability to leverage supplier resources. The procurement organization also includes a governance function that ensures that procurement activities are conducted in a prudent manner that complies with corporate practices and controls and the Sarbanes-Oxley requirements. The procurement budget consists primarily of internal labor expense and also contains modest expenses for outside services. The budgeted costs associated with PSEG LI's procurement functions are set forth on Exhibit __ (SSP-1).

Q. What security operations does PSEG LI provide for LIPA?

A. PSEG LI is responsible for providing security at facilities across LIPA's service territory. The costs of providing security primarily consist of services purchased from third-party vendors through a competitive process. PSEG LI also has an internal staff to oversee security. The budgeted costs of security operations are set forth on Exhibit __ (SSP-1).

Q. How does PSEG LI manage its human resources functions?

A. PSEG LI has a staff dedicated to managing human resources and also uses the centralized services of PSEG Services to assist in providing the full range of necessary human resources services. These services include:

- Staffing;
- Development and administration of a comprehensive total compensation package;
- Development and maintenance of uniform human resources policies;
- Administration of employee benefits including pensions and other post-employment benefits;
- Operation of human resources-related information systems;
- Talent acquisition and diversity outreach;
- Operational effectiveness evaluation and development;
- Management of our relationship with the union workforce;
- Development and administration of human resources budgets; and
- Development and administration of human resources-related analytical tools.

The costs incurred for outside services in the human resources area are primarily for various consulting services. The budgeted costs for human resources are set forth on Exhibit __ (SSP-1).

Q. Please describe the expenses for communications reflected in PSEG LI's business services budgets.

A. These expenses are incurred to enable PSEG LI to properly communicate with customers, employees and other stakeholders. The budget for these services represents costs for labor and associated benefits as well as nominal expenses for travel throughout LIPA's service territory and office supplies. The budgeted costs for communications are set forth on Exhibit __ (SSP-1).

Q. Please describe the expenses for public affairs reflected in PSEG LI's business services budgets.

A. These expenses are incurred to enable PSEG LI to properly communicate with government officials and community members in LIPA's service territory about our services and planned site improvements. The budget for these services represents costs for labor and associated benefits as well as nominal expenses for travel throughout LIPA’s service territory and office supplies. These costs are set forth on Exhibit __ (SSP-1).

Q. Does PSEG LI maintain an internal audit department?

A. Yes. The Internal Audit department is an independent objective function within PSEG LI. It reports to the Vice President-Internal Audit Services of PSEG Services. An Audit Universe has been developed and is updated annually based on a risk assessment exercise. The Audit Universe is used as the basis for the creation of the annual Audit Plan for PSEG LI. Audits, reviews, investigations and internal controls testing are conducted throughout the year and the results are shared with management and corrective actions are taken, where applicable. The Internal Audit budget for CY 2016 through CY 2018 represents primarily labor and minimal costs associated with travel, training and office supplies. The budgeted costs of internal audit are set forth on Exhibit __ (SSP-1).

Q. Does this conclude your testimony?

A. Yes, it does.

JUDGE PHILLIPS: The next panel?

MR. WEISSMAN: The next panel, Your Honors, are actually two affidavits for the PSEG Long Island Budget Panel submitted on January 30th. It is a 14 page document with a single exhibit. The first affidavit is executed by Gary Ahern and Lisa Figliozzi. The second affidavit was executed by Mr. Richard Aicher.

Those are the three members of that panel. It's a single exhibit identified as Exhibit 10 pre-filed BP-1. It is a five-page document providing the Overview Budget by Director (handing).

JUDGE PHILLIPS: We have been provided with the affidavit of Budget Panel, two affidavits, which we marked. The first one done by Mr. Ahern and Ms. Figliozzi we marked as Exhibit 121. The affidavit of Mr. Aicher of that same panel has been marked for identification as Exhibit 122.

On the basis of these two exhibits, we ask that the testimony of the PSEG LI Budget Panel consisting of 14 pages as previously described be copied into the record as though given orally today.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-____________

DIRECT PRE-FILED TESTIMONY
OF
THE BUDGET PANEL

Date: January 30, 2015

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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Budget Panel (the "Panel").

A. We are Gary S. Ahern, Richard L. Aicher and Lisa Figliozzi.

Q. Mr. Ahern, please state your employer and business address.

A. I am employed by PSEG Long Island LLC ("PSEG LI" or the "Company") and my business address is 333 Earle Ovington Blvd., Uniondale, NY 11553.

Q. In what capacity are you employed by the Company?

A. I am employed by the Company as Director of Finance. In this position I am responsible for, among other things: regulatory filings on behalf of the Long Island Power Authority ("LIPA"); maintaining LIPA's Tariff; Electric Customer Rates and Pricing; PSEG LI Financial Statements; PSEG LI Accounting; PSEG LI Budgeting and Forecasting; billing and collections from LIPA; and non-utility billing on behalf of LIPA.

Q. Please state your relevant education and work experience.

A. Prior to assuming my position with PSEG LI, I was Vice President, U.S. Regulation and Pricing -- Gas Distribution for National Grid Corporate Services, LLC, which provides engineering, financial, administrative and other technical support to direct and indirect subsidiary companies of National Grid USA. My duties included revenue requirements and pricing oversight for the U.S. gas distribution subsidiaries of National Grid USA, including National Grid's New York gas utilities The Brooklyn Union Gas Company, Keyspan Gas East Corporation and the gas operations of Niagara Mohawk Power Corporation, as well as Boston Gas Company, Colonial

Gas Company, and Essex Gas Company. I joined Brooklyn Union Gas Company (a predecessor company of National Grid KeySpan Corporation) in 1975 where I held a number of financial positions within Brooklyn Union, KeySpan Corporation and, most recently, National Grid. I worked in the Corporate Planning Department for Brooklyn Union as a financial analyst and was appointed to oversee Brooklyn Union's regulatory filings with the New York State Public Service Commission ("PSC"). From 1993 through 2001, I served as the Corporate Budget Director of Brooklyn Union and (beginning in 1998) for KeySpan Corporation. In 2001, I was appointed the Director of Finance for the Electric Business Unit, where I was responsible for providing financial services, controls and analysis to support the electric operating companies, among other responsibilities.

In 1982, I earned a Bachelor of Arts degree in Business Management/Accounting from Saint Francis College. In 1986, I earned a Masters of Business Administration from Adelphi University.

Q. Mr. Aicher, please state your employer and business address.

A. I am employed by PSEG Services Corporation ("PSEG Services") and my business address is 80 Park Plaza, Newark, NJ 07102.

Q. In what capacity are you employed by PSEG Services?

A. I am employed by PSEG Services as Manager of Utility SAP Strategy and Planning. In this position I am responsible for the configuration of several SAP modules to support the external and internal reporting of Public Service Electric and Gas Company ("PSE&G"). I manage the budget planning process for PSE&G and provide financial support for State and Federal regulatory proceedings. Additionally I provide support for cost allocation methodology creation and implementation and provide litigation support. I have also been supporting the PSEG LI migration to the Public Service Enterprise Group ("PSEG") SAP system and the development of the 2015 PSEG LI budget.

Q. Please summarize your educational background and professional experience.

A. I joined PSEG in 1997. Prior to my current position, I held a variety of positions relating to the planning, budgeting, accounting system support and regulatory support for both PSE&G as a whole and for the Customer Operations and Appliance Service lines of business. Prior to joining PSEG, I spent ten years in various management positions for Jersey Central Power & Light Company and five years in engineering positions for Pennsylvania Power & Light Company. I have Bachelor of Science and Master of Science degrees in Engineering from Duke University and a Master of Business Administration degree from Seton Hall University.

Q. Ms. Figliozzi, please state your name and business address.

A. My name is Lisa Figliozzi. My business address is One Hundred East Old Country Road, Hicksville, New York 11801.

Q. By whom are you employed and in what capacity?

A. I am Manager, Regulation and Pricing – PSEG LI. My current duties include revenue requirements oversight for PSEG LI and for LIPA.

Q. Please summarize your educational and professional background.

A. I joined the Long Island Lighting Company ("LILCO") (a predecessor company of KeySpan Corporation) in 1990. Since that time, I have held a number of financial and accounting positions within LILCO, KeySpan Corporation and, most recently, National Grid. I worked in the Corporate Budget and Planning Department for LILCO as a financial analyst and was promoted to Manager, LIPA Reporting in 1998 when Brooklyn Union merged with the LILCO. I supported regulatory filings and developed financial exhibits that were presented to the PSC, FERC, NYSERDA, and LIPA. From 2004 through 2005, I served as the Budget Manager of the Ravenswood generation power plant, which supplied twenty percent of New York City's power. In 2006, I was a functional team leader for Keyspan's Property Records software implementation project, and subsequently during the integration period with National Grid I was appointed the Manager of Plant Accounting. Plant Accounting was headquartered in Massachusetts, with offices in Buffalo, Syracuse, Glens Falls, Rhode Island and Long Island. I was responsible for centralizing Plant Accounting Operations on Long Island and providing asset accounting functions, including closing, financial and regulatory reporting, services, controls and analysis to support the US Operations. In 2010 I assumed the role of Principal Analyst for Revenue Requirements of the New York gas companies for National Grid. In October 2012 I was selected as Manager of Regulation and Pricing supporting LIPA, which is my current role.

I hold a Bachelor of Science degree in Business Management/Finance from Long Island University (1989) and a Master of Business Administration/Finance from Long Island University (1995).

Q. What is the overall purpose of the Panel's testimony in this proceeding?

A. The purpose of this Panel's testimony is to explain the processes that were followed in developing the base year 2015 budget and to present the PSEG LI budgets for the three years of the Rate Plan, 2016, 2017 and 2018. We then explain that those PSEG LI budgets were consolidated by the Ratemaking and Revenue Requirements Panel with LIPA's 2016, 2017 and 2018 budgets to produce the Three-Year Consolidated Budgets that form the basis of the Rate Plan.

Q. Is the Panel sponsoring any exhibits in support of its testimony?

A. Yes. Exhibit ___ (BP-1) sets forth the PSEG LI 2015 approved budget at the director level as well as the forecasted 2016, 2017 and 2018 budgets.

II. <u>PSEG LI BUDGET PROCESS</u>

Q. Please describe the process by which the budgets were developed.

A. The budget process rested overall responsibility for each general functional area with the Vice President in charge of that area. PSEG LI's Vice Presidents all worked closely with their respective directors and the budget team to produce the budgets being presented here. The Transmission and Distribution ("T&D") organization is divided into seven major areas of responsibility: (1) T&D VP Operations Other (including Emergency Planning); (2) T&D Overhead and Underground ("OH &

UG"); (3) T&D Operations; (4) Substation/Protection/Telecom ("SPT"); (5) Projects and Construction; (6) T&D Services; and (7) Asset Management. The Customer Services organization is composed of four separate areas of responsibility: (1) Customer Contact and Billing; (2) Revenue Operations; (3) Customer Experience and Utility Marketing; and (4) Meter Services. The Shared and Business Services organization is composed of six separate areas: (1) Business Performance Excellence ("BPE"); (2) Information Technology; (3) Facilities Management; (4) Finance and Accounting; (5) Procurement; and (6) Security Operations. The Shared and Business Services budget also includes costs for functions that report to the President i.e., Communications, Public Affairs, Human Resources ("HR"), Legal Services, and General Manager – Internal Audit. Lastly, Energy Efficiency and Renewable Energy, and Power Markets, are organizations that are separately stated. The functions performed by all of these organizations and the costs required to perform them are presented in detail by the respective panels addressing T&D, Customer Services, Power Markets, Shared and Business Services, and Energy Efficiency and Renewable Energy. The budget team assisted the functional groups in the production of individual budgets for those functional areas by providing existing headcount, compensation and benefits information, and introductory training to the PSEG SAP system and budgeting process, and worked with the groups on developing the organizational structure, mapping of employees to activity types, and identification of work activities (orders) that will be used for both planning and reporting. The functional areas then provided the budget team with adjusted headcounts, overtime percentages, allocations of labor to work activities, and expenses by work activity for materials, contractors and outside services and other miscellaneous expenses. Based on the input from the respective functional teams, an overall PSEG LI budget for 2015 was developed.

Q. You previously referred to the 2015 budget as a "base year" budget. Why was 2015 determined to be a base year upon which to develop subsequent budgets?

A. PSEG LI took over responsibility for the operations of LIPA's T&D system on January 1, 2014. Prior to that time, the system was operated by National Grid under a Management Services Agreement ("MSA"). The responsibilities of PSEG LI under the Amended and Restated Operating Services Agreement dated as of December 31, 2013 ("OSA") differ significantly from those of National Grid under the MSA. Consequently, cost information for activities that took place prior to PSEG LI taking over responsibilities for the LIPA system is not readily available and is of limited use.

Furthermore, 2014 was a transitional year, during which PSEG LI was adjusting to running the LIPA system, changing operations and developing new processes. Consequently, using the 2014 budget as a baseline budget for the 2016-2018 Rate Plan would have been problematic. In fact, PSEG LI's 2014 operating costs had been budgeted in the fall of 2013 by the transition team, before PSEG LI commenced operations and before employees were even hired to operate the Long Island system.

Q. What is fundamentally different between the 2014 and 2015 budget years that make 2015 a better starting point for the rate years of 2016, 2017 and 2018?

A. The 2014 budget included costs and resources at a functional area level and did not identify type of work nor was it expressed in a FERC accounting format. The 2015 budget was developed by employees representing the functional areas using a "bottom up" approach in that they identified the work activities being performed and the costs (labor, material, outside services, and other) required to perform the work activity. Significantly, the 2015 budget was developed with experience of having actually managed the system as opposed to the 2014 budget, which was developed before PSEG LI actually took over operations. Additionally, for 2015 the PSEG planning tool and SAP system were available and were used to centralize the data, perform clearing and FERC accounting, and provide more detailed information for budget and actual reporting and analysis. Another benefit of the SAP budget model is that it will enable internal budget versus actual reporting directly out of the SAP system. Prior to 2015, reporting was performed manually in excel spreadsheets. Access to the detailed accounting data through the SAP system will enable comprehensive reviews and analysis leading to improved financial management of the business previously unavailable.

Q. Does the 2015 base year budget reflect cost constraints?

A. Yes. Both the 2014 and 2015 budgets were developed to meet the delivery rate freeze commitment that PSEG LI and LIPA had made until the commencement of new rates on January 1, 2016. In order to meet the rate freeze, it was also necessary to make additional reductions and expense deferrals in 2015 over the 2014 levels. The goal of the LIPA Reform Act and the OSA was to improve customer satisfaction to first quartile levels for the industry over five years. Although PSEG LI has made significant progress in just the first year of operations, the rate freeze budgets were not adequate to permit PSEG LI to reach first quartile levels. Consequently, PSEG LI's ability to constrain the budget in this manner was only temporary, necessitating a more sustainable spending pattern in 2016 and beyond.

Q. Once the budget team obtained the headcount, activity levels and other information from the functional groups in their budgets, what were the next steps in that process?

A. We assisted those groups in developing their respective functional budgets for the 2015 base year. The functional budgets presented for T&D, Customer Services, Shared and Business Services, Energy Efficiency and Renewable Energy, and Power Markets are the results of that process. Expenses from PSEG Services and PSE&G, as well as wages, salaries, fringe benefits and payroll taxes were also loaded into the SAP system. After all the data was loaded into the SAP system, clearing allocations were run, income statement and total capital spending views based on work activity or capital project were developed, and a FERC accounting view of costs was produced. The SAP system provides multiple views of costs (by resource, by functional area, by direct versus clearing, and by FERC account).

Q. How was payroll information for wages, salaries and benefits provided to the groups who assembled the budgets?

A. The necessary information was provided to the individuals working on the budgets by the HR organization. A listing of the employees comprising the PSEG LI organization was provided to the group developing the budget. That group then organized the list into the organizational structure (cost centers and activity types) for the 2015 Budget and sent this information back to the HR group. The HR group then provided current compensation data for each organizational structure. For example, upon a query for the T&D OH/UG (overhead and underground) subgroup within the T&D group, the team assembling the budget could obtain from HR the necessary compensation cost information for all of the union and non-union management, administrative supervisory and technical ("MAST") employees in that subgroup by activity type.

Q. You previously mentioned "clearing allocations." What is clearing?

A. Clearing costs are costs which cannot easily be directly charged to a particular work activity but support a variety of work activities. Examples of clearing costs include manager and administrative support, fleet and fuel, material handling, facilities, information technology and fringe benefits. The costs to be cleared for a given area are collected in clearing pools and then allocated to the work activities performed by that area to ensure that costs are properly allocated between O&M and capital. Direct charging is used whenever possible and practical. Manager and administrative support clearing is applied to total payroll, union payroll, or a combination of payroll and contractors, and is reflected in the budgets presented in the testimony of the T&D, Customer Operations, Shared and Business Services, and Power Supply panels. Fringe Benefits, OPEBs and Pensions are budgets provided by HR and Treasury Services to be systematically cleared over payroll. Payroll Taxes is another loading estimated at 7.6% of total payroll. Fleet and fuel loadings are applied to payroll in each organization based on number of vehicles and fuel usage. Facilities costs were allocated to organizations based on number of employees by location and then cleared over the work activities of that organization based on payroll and contractor costs. Materials handling is a loading applied to materials budgeted in the organizations as withdrawn from the store-room. Information technology clearing is loaded by organization being served and is applied to payroll and contractors.

Q. What differed between the budgets presented by the individual groups and the 2015 base year budget that this Panel is presenting?

A. The most obvious difference is that the individual efforts were then consolidated by us into a 2015 base year budget for PSEG LI. The individual group's budgets did not reflect the total allocation of clearing costs and were not presented in a FERC accounting format.

Q. Is it significant that the PSEG LI budget is presented in a FERC Account format?

A. Yes it is. The use of FERC accounts presents information in a rigorous and useful manner that is amenable to the audits and other oversight activities that the LIPA Reform Act has determined should be performed by the Department of Public Service ("DPS").

Q. Were any constraints imposed on the budgets for the period of the Rate Plan in this filing?

A. No, there were not. We previously discussed the 2015 constraints to accommodate the rate freeze. The T&D Budget and Operations Panel, for example, cites the example of tree trimming, which ideally should be done on a four-year cycle but which deferred moving to this cycle until 2016. As the T&D Budget and Operations Panel explains, such temporary spending constraints to facilitate the rate freeze would not permit PSEG LI to provide an industry-standard level of service quality and reliability if continued indefinitely. Other instances where spending is constrained in 2015 but reflects more normal and sustainable spending levels necessary during the 2016 to 2018 period to support the effort to move to a first quartile level are addressed in the testimony of the T&D Budget and Operations and Customer Services Budget and Operations panels. For these reasons, we adjusted certain activity levels for 2016, 2017, and 2018 such as tree trimming and substation maintenance to restore normal maintenance cycles. We then set inflationary targets for the 2016, 2017, and 2018 rate years. The budgets also took into account any activity level changes explained in the individual budgets. Finally Productivity Adjustments of $0.6 million, $2.5 million, and $7.2 million, respectively, were imposed on the 2016, 2017, and 2018 budgets.

Q. Does the 2015 budget differ from the budgets for 2016, 2017 and 2018?

A. Yes. The 2015 budget is a comprehensive budget that consists of thousands of separate lines of budget data. The system enables reporting on a number of different categories established in the SAP data structure. Examples include cost center, cost element (which is the type of work being performed such as labor, materials, contractor), and order (which is the description of the work being performed). Because of the level of detail contained in this budget, a high level representation of the 2015 budget is presented on Exhibit ___ (BP-1).

Q. How were the 2016, 2017 and 2018 budgets developed from the 2015 comprehensive budget?

A. The 2016, 2017 and 2018 budgets were escalated for specific factors such as inflation, wage, salary and benefit increases and known activity level changes such as placing the tree-trim and maintenance on optimal cycles, adding employees where necessary and reflecting additional known increases or decreases to costs and projects. The budgets for 2016, 2017 and 2018 are set forth at the Director level with the specific activity and cost level changes shown. These budgets are also presented on Exhibit ___ (BP-1).

III. <u>CONSOLIDATED BUDGETS – 2016-2018</u>

Q. What was the next step in the budget process?

A. Under the OSA, it is PSEG LI's responsibility, upon obtaining LIPA's budgets for the years in the Rate Plan, to consolidate those budgets with PSEG LI's budgets to produce consolidated budgets for each year in the Rate Plan.

Q. Did LIPA's personnel provide you with its budgets?

A. Yes, they did, and we worked closely with them to integrate the budgets and to ensure that they accurately portrayed the appropriate cost information.

Q. Are you presenting those consolidated budgets?

A. No. The consolidated budgets were developed in a process that also results in the revenue requirement in this case. Consequently, the consolidated budgets are presented by the Ratemaking and Revenue Requirements Panel. The LIPA budgets are subsumed within the Revenue Requirement developed for this case.

Q. Did you independently verify the information in the budgets that LIPA provided to you?

A. In some cases we did and in some cases we did not. The following costs, which are PSEG LI managed expenses, are booked in LIPA's general ledger: Utility Depreciation; National Grid Power Supply Agreement; Nine-Mile Point II O&M; NYS Assessments; Uncollectibles; Storms; Accretion of Asset Retirement Obligation; and Revenue and Property PILOTs. On the other hand, we accepted LIPA's information about the refinancing of debt and debt service costs, debt coverage, LIPA's employee costs, various contractually obligated payments and the like, which are LIPA's responsibilities and were contained in LIPA's budget presentations. We then worked with LIPA personnel to consolidate LIPA's budgets with PSEG LI's budgets for the years in question to produce a consolidated budget that the Ratemaking and Revenue Requirements Panel used to produce the revenue requirements for the three years of the Rate Plan.

Q. Does this conclude the Panel's direct testimony at this time?

A. Yes, it does.

JUDGE PHILLIPS: The next panel?

MR. WEISSMAN: The next affidavit, Your Honor, covers Mr. Trainor's affidavit which covers both the Direct Prefiled Testimony of Joseph Trainor on Cost of Service and Rate Design as well as Mr. Trainor's exhibits that was filed on January 30, 2015 as well as the rebuttal testimony of Mr. Trainor on those same subjects which was filed on June 10, 2015.

The direct testimony consists of 56 pages and six exhibits. The rebuttal testimony consists of 34 pages and six additional exhibits. Would you like me to describe briefly each of those twelve exhibits? I can do that. They're identified.

JUDGE PHILLIPS: Can you just give me their numbers, the range of numbers, as they are set forth in the exhibit list prepared by the parties?

MR. WEISSMAN: That would be fine, Your Honor. The direct testimony exhibits are designated Exhibit Numbers 23 through 30. That is because one of the exhibits had several schedules that were separately identified. The rebuttal testimony exhibits are identified as Exhibits 31 through 36. The exhibits vary in length and size. There is Mr. Trainor's affidavit covering both of those pieces of testimony and a full set of exhibits (handing).

JUDGE PHILLIPS: We have marked for identification as Exhibit 123 the affidavit of Joseph Trainor, Cost of Service, Rate Design and Tariff Issues. On the basis of this affidavit, we ask that his pre-filed direct testimony consisting of 56 pages and his rebuttal testimony consisting of 34 pages be copied into the record as though given orally today.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-____________

DIRECT PRE-FILED TESTIMONY OF JOSEPH TRAINOR ON COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

Date: January 30, 2015

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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Mr. Trainor, please state your name and business address.

A. My name is Joseph T. Trainor. My business address is 175 E. Old Country Road, Hicksville, NY 11801.

Q. By whom and in what capacity are you employed?

A. I am employed as a Senior Manager in Rates and Pricing for PSEG Long Island LLC ("PSEG LI" or the "Company").

Q. What are your responsibilities?

A. My responsibilities include managing the rates and pricing department, which is responsible for strategic planning, cost-of-service, rate design, financial due diligence, financial analysis, tariff and overall ratemaking management, and rate case and litigation support.

Q. Please describe your education, experience and employment history.

A. My educational background and professional experience are outlined in my curriculum vitae, which is attached as Exhibit __ (JTT-1).

Q. Have you previously testified before any regulatory commission?

A. Yes, I have testified previously before the New York Public Service Commission ("PSC"). A brief description of my previous experience as a witness is included as part of Exhibit __ (JTT-1).

Q. What is the purpose of your testimony in this proceeding?

A. As part of the three-year Rate Plan proposal being submitted on behalf of PSEG LI, the purpose of my testimony is to present the following:

1. The forecast of total operating revenues, including all proposed revenue requirement changes for the twelve months ending December 31, 2016 ("CY 2016"), December 31, 2017 ("CY 2017"), and December 31, 2018 ("CY 2018");
2. The results of an embedded class cost of service study ("ECOSS") and a marginal cost of service study ("MCOSS") performed for the Long Island Power Authority ("LIPA");
3. The proposed rate design for each service classification under LIPA's tariff for electric service;
4. Proposed changes in LIPA's tariff, including a proposed new Delivery Service Adjustment ("DSA"), an increase in the residential low-income discount, a new Standby service classification, proposed changes in various fees assessed under the tariff, and other tariff changes as described more fully below; and
5. A proposal for a collaborative to address retail choice issues.

Q. What are the major issues addressed in your testimony?

A. My testimony addresses the following issues. I will:

1. identify the principles and methodologies used to perform both the embedded and marginal cost of service studies;
2. provide the justification for tariff language changes;
3. set forth PSEG LI's recommendation concerning LIPA's retail choice program known as Long Island Choice ("LI-Choice"); and
4. provide the justification and calculation for a number of rate design proposals including:
    i. increasing Kilowatt ("KW") based demand rates;
    ii. increasing the customer charge on all service rate classes;
    iii. combining and simplifying the residential service rate classes;
    iv. combining the grandfathered service sub-classes from 1983 with their current corresponding service classes;
    v. modifying certain service classes' transfer clauses;

vi. changing certain service classes' demand ratchets;
vii. modifying the residential low income discount;
viii. modifying Standby rates and terms of service;
ix. proposing adoption of a Delivery Service Adjustment ("DSA"); and
x. modifying certain service fees.

Q. Please list the exhibits you are presenting with your testimony.

A. I am presenting the following exhibits:

Exhibit __ (JTT-1):	Curriculum Vitae of Joseph T. Trainor
Exhibit __ (JTT-2):	Methodology and Results of CY 2016 ECOSS
Exhibit __ (JTT-3):	Methodology and Results of CY 2016 MCOSS
Exhibit __ (JTT-4):	Allocation of Revenue Requirements, Proof of Revenue and detailed bill impact statements.
Exhibit __ (JTT-5):	Proposed Tariffs for CY 2016, CY 2017 and CY 2018
Exhibit __ (JTT-6):	Listing of Proposed Tariff Changes

Q. Please describe the sections of your testimony.

A. Section II identifies the ECOSS principles and allocation methods. Section III presents the detailed results of the ECOSS for CY 2016. Section IV presents the results of the MCOSS. Section V describes and supports the various principles of rate design and Section VI presents the proposed revenue allocation and rate design for LIPA for CY 2016, CY 2017 and CY 2018. Section VII presents proposed changes to LIPA's Standby Service classification. Section VIII presents and discusses the proof of revenues. Section IX presents the proposal for a new DSA. Section X describes the proposed non-rate tariff modifications. Section XI describes proposals for LI-Choice. Section XII presents a summary of my recommendations.

II. ECOSS METHODOLOGY

Q. Please describe the purpose of performing an ECOSS.

A. There are many purposes for utility cost analysis ranging from designing rates that reflect appropriate price signals to determining the share of costs or revenue requirements borne by various customer rate classes. In this case, an embedded cost study is a useful guide for the allocation of LIPA's revenue requirements. A bundled fully-allocated ECOSS analyzes all the functional components of the utility's cost-of-service and assigns plant investments and operating expenses, including fuel supply costs, to arrive at a determination of the total costs incurred by the utility in providing products and services to each customer rate class. Each component of plant, expenses and revenue is allocated among the existing customer rate classes, to determine the portion of the total costs incurred by LIPA that can be attributed to the various customer rate classes based on "cost causation" principles.

Cost causality describes the cause and effect relationship between customer requirements, load profiles and usage characteristics, and the costs incurred by the utility to serve those requirements. In preparing an ECOSS, all of the utility's costs of providing service must be analyzed and allocated among the customer rate classes.

One of the results provided by the ECOSS is the revenue to cost ratio for each customer rate class (as defined above), which can be analyzed to determine if the revenue produced by the current rates produces inter-class subsidies. These results for LIPA are shown in Exhibit __ (JTT-2), Section 3. Another result is the calculation of the revenue required from each customer rate class in order for that customer rate class to pay for all of its assigned costs. These results for LIPA are shown in Exhibit __ (JTT-2), Section 4, Schedule E.

Q. Please discuss the reason for preparing an ECOSS.

A. Embedded cost studies attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs. In addition, utility costs may be fixed or variable. Finally, utility costs exhibit significant economies of scale. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of embedded cost studies requires an understanding of the operating characteristics of the utility system. Further, as discussed below, embedded cost studies provide valuable information to the development of economically efficient rates and the cost responsibility for each customer rate class.

Q. Please describe how an ECOSS is prepared.

A. The general approach utilizes a three-step process to analyze each component of plant, expenses, and revenue. The first step is functionalization of each element according to its place in LIPA's delivery chain. For LIPA, these functions are production, transmission, primary distribution (13Kv), secondary distribution, Customer Records and Collections. The second step is classification of each functionalized cost element according to the usage characteristic it satisfies. For LIPA, these classifications are demand/capacity, energy/commodity, or customer.

For simplicity of presentation LIPA's ECOSS model combines the functionalization and classification steps into one schedule. The final step is class allocation. Class allocation comprises the allocation of each functionalized and classified cost element among the customer rate classes, taking into account each customer rate class's consumption levels and consumption characteristics.

Q. What is the purpose of the functionalization step of an ECOSS?

A. In the functionalization step, costs are separated by basic service functions. For purposes of the ECOSS, these functions have been identified as follows:

- Production – All facilities used to supply electricity to the transmission and distribution system.
- Transmission – Bulk transmission system, designed to move power from generation sources to the primary distribution system, operating at voltages of 138 kV and up.
- Primary Distribution – Designed to move power from the transmission system to the secondary distribution system and to customers' premises; includes substations as well as conductors operating at voltages of 2.4kV up to 13 kV and related assets.
- Secondary Distribution – Designed to move power from the primary distribution system to customers' premises, includes service drops.
- Customer Records and Collections – The utility's back office functions that enable the utility to read meters, calculate and mail bills, provide customer service and perform collections.

Q. What are the purposes of the classification step of an ECOSS?

A. In the classification step, the previously functionalized accounts are classified as Demand/Capacity, Commodity, or Customer, according to the system design or operating characteristics that cause them to be incurred. Demand- or capacity-related costs are associated with plant that is designed, constructed, and operated to meet system peak demand or non-coincident class peak demand. Commodity-related costs vary with electricity sold to or delivered to customers. Customer-related costs are incurred to attach a customer to the distribution system, to meter the customer's usage, and to maintain both customer-related distribution assets and the customer's account. Customer-related costs are primarily a function of the number of customers served, and they continue to be incurred regardless of whether a particular customer uses any electricity, and typically do not vary with usage or load profile. They include capital costs associated with the customer portion of the primary and secondary distribution system, services and meters, operating costs associated with those assets, as well as costs of performing customer service, field service, billing, and accounting.

Q. What is the purpose of the class allocation step of the ECOSS?

A. In the class allocation step, the functionalized, classified costs are allocated among the rate classes based on causal relationships. These relationships are determined by analyzing a utility's system design and operations, its accounting records, and its system and customer load data. Based on those analyses, each asset and cost is either directly assigned to a rate class or an appropriate cost allocator is chosen.

Q. Please summarize the cost of service approach that you followed in performing the ECOSS.

A. The most critical task in performing an ECOSS is establishing relationships between customer requirements, load profiles, and usage characteristics, and the costs incurred to serve those requirements. LIPA has designed its integrated system to meet three primary objectives:

1. to extend delivery services capabilities to all customers;
2. to meet the aggregate capacity requirements of all customers entitled to receive service at peak hours and on peak days; and
3. to deliver energy (kWh) and capacity (kW) to those customers.

It is important that the allocation methods used in the ECOSS recognize these cost drivers for LIPA's plant investments and operating expenses. The ECOSS should objectively reflect cost causation factors attributable to the utility's customers, their energy usage requirements, and system operations, and to the extent possible, should not be influenced by desired end-results, customer equity, or other rate design considerations. Those issues can be addressed through policy decisions outside of the ECOSS process.

The ECOSS was performed using LIPA's EXCEL based spreadsheet Electric ECOSS Model ("Model"). The Model is structured to support the three-step process that I previously described.

Q. What customer rate classes are included in the ECOSS?

A. The following is a list of service classes and the corresponding rate codes identifying the eleven customer rate classes presented in the ECOSS:

1. <u>Residential - Non Time of Use ("TOU"):</u> Service Classification No. 1 (Rate Codes: 180, 183, 186, 380, 480, 481)
2. <u>Residential Heat:</u> Service Classification No. 1 (Rate Codes: 580, 581, 880, 881, 882, 883)

3. Residential TOU: Service Classification No. 1-VMRP (Rate Codes: 181, 182,184,188)
4. Small Commercial: Service Classification No. 2 & No. 2-VMRP (Rate Codes 280, 288)
5. Large Commercial: Service Classification No. 2-L & No. 2-H& No. 2LVMRP (Rate Codes 281, 282, 283, 290, 291, 293)
6. Mandatory Large Demand Metered Service with Multiple Rate Periods: Service Classification No. 2-MRP (Rate Codes 284, 285)
7. Back-Up and Supplemental Service: Service Classification No. 12 (Rate Code: 681)
8. Recharge NY Delivery Service: Service Classification No. 2-MRP (Rate Code 680)
9. Long Island Rail Road: Service Classification No. 13
10. Private Outdoor Lighting: Service Classification No. 7 (Rate Codes 780, 781, 782)
11. Traffic Signal Lighting and Public Street and Highway Lighting Energy and Connections: Service Classification No. 5 & No. 10 (Rate Codes 980, 1580, 1581)

The eleven categories above without inclusion of SC-13 (except for the Long Island Rail Road) will be referred to as LIPA's customer rate classes. The ECOSS presents the revenues from SC-13 as other revenues allocated to all other customer rate classes.

Q. Does LIPA's tariff contain service classifications that are not included as customer rate classes in the ECOSS?

A. Yes. Service Classification No. 11 sets forth the terms and conditions under which LIPA provides "Buy-Back service" to electric generation customers. Service Classification No. 14 sets forth the terms and conditions of LIPA's service to energy service companies ("ESCOs") under LIPA's retail choice program. Service Classification No. 16 sets forth the terms of LIPA's advanced metering initiative pilot program. Customers served under these service classifications take service under another service classification as well. Thus, there is no reason to include these service classifications in the ECOSS.

Q. How did you determine the appropriate approach for functionalizing, classifying, and allocating each component of plant, annual expense and revenue?

A. Selection of the appropriate approach for functionalizing, classifying and allocating each component of plant, annual expense, and revenue was based on careful consideration of cost causality, as well as PSC precedent and generally accepted utility and regulatory practices.

Q. Please explain how allocation bases are derived.

A. Two types of allocation bases, or allocators, are typically used in performing an ECOSS and employed in the ECOSS Model: external allocators and internal allocators. External allocators are based on special studies derived from data in the utility's accounting and other records. For example, an external allocator has been developed based on energy sales and the volume of energy consumed by each customer rate class, and is used to allocate fuel costs. Other examples of factors used to develop external allocators are number of customers, load research results such as non-coincident peak and coincident peak, load demand factors, and historical collection experience. Exhibit __ (JTT- 2), Section 6, describes the main external allocators that were developed for use in the ECOSS.

Q. What are internal allocators?

A. Internal allocators are based on some combination of external allocators, previously directly assigned costs, and other internal allocators. For example, the allocators for property insurance (FERC Account 924) costs are based on plant investment amounts; it is necessary to compute the plant investment at each step of the model (i.e. functionalization, classification, and allocation by customer rate class) before property insurance costs can be assigned. Both external and internal allocators are used in each of the allocation steps.

Q. What data did you use in preparing the ECOSS?

A. The ECOSS study results are presented using the proposed revenue requirement for CY 2016. This is the same data presented by the Revenue Requirements Panel. This data was developed using a public power revenue requirement model and thus it was not developed and is not available by FERC account, and does not include forecast plant balances. However, that information is needed to develop the allocation factors used in the ECOSS. Accordingly, net plant balances as of December 2013 and operation and maintenance expenses by FERC account based on the 2016 PSEG LI budget were used to prepare the ECOSS.

III. PRESENTATION OF THE RESULTS OF THE FY 2016 ECOSS

Q. Please describe Exhibit __ (JTT-2).

A. This exhibit describes the methodology that was used to perform the ECOSS and presents the results of the ECOSS. The methodology used in the exhibit follows the general ECOSS principles outlined above. Exhibit __ (JTT-2) is divided into six sections:

- Section 1 - Introduction – an overview of the ECOSS
- Section 2 - ECOSS Assignments and Allocation - This section describes how each plant, expense, and revenue component of the ECOSS was assigned or allocated in the three step process: Functionalization, Classification, and customer rate class Allocation. Plant, expenses, and revenues are listed in detail using either budget line references or the Uniform System of Accounts (FERC Accounts). The remainder of the testimony will refer to the ECOSS line details as the Detail Account Listing. This section will also serve as a guide when reviewing the functionalized, classified and allocated details in Section 4 of Exhibit __ (JTT-2).
- Section 3 - Results by customer rate class - This section presents the revenue to expense ratio for each of the previously defined customer rate classes.
- Section 4 - Detailed model printouts - This section contains detailed ECOSS schedules:
    - **Schedule A:** The cost-of-service results by Detail Account Listing for each plant, expense, and revenue item functionalized, classified and allocated to each customer rate class and showing the revenue to expense ratio;
    - **Schedule B:** Functionalized cost-of-service by Detail Account Listing for each plant, expense, and revenue item functionalized;
    - **Schedule C:** Classified cost-of-service by Detail Account Listing for each plant, expense, and revenue item;
    - **Schedule D:** By Function, By Classification -- a detailed list of each plant, expense and revenue item allocated to each customer rate class, showing the calculated revenue to expense ratio;

- **Schedule E:** This section describes how each plant, expense and revenue component of the ECOSS was assigned or allocated in each of the three steps - Functionalization, Classification, and Summary Schedule Allocation. Plant, expenses and revenues are listed in detail using both the Budget and the Uniform System of Accounts (FERC Accounts). This section will also serve as a guide when reviewing the functionalized, classified and allocated detailed exhibits in Section 4, which are also presented using the Uniform System of Accounts.
- **Schedule F:** Presents the Unit Costs per Rate Class.

- Section 5 - Listing of internal and external allocators for each Rate Class.
- Section 6 - Presents a summary description of main external allocators.

Q. Please summarize the ECOSS results by customer rate class as shown on the summary table in Exhibit __ (JTT-2), Section 3.

A. The summary table in Exhibit __ (JTT-2), Section 3 shows the results of the revenue to cost ratio for each customer rate schedule. This table indicates the following results based on the costs incurred to serve the various customer rate schedules:

- the residential customer service classes recover less than the fully allocated cost of service;
- the commercial service classes recover more than the fully allocated cost of service.

IV. <u>MARGINAL COST OF SERVICE STUDY</u>

Q. Please briefly describe the theory and purpose of performing a Marginal Cost of Service Study ("MCOSS").

A. The purpose of a MCOSS is to determine the marginal cost of providing incremental service to certain of LIPA's largest service classes. This study is used to set the Excelsior Jobs Program rates. Marginal cost studies focus on the change in costs associated with a small change in output. Marginal costs are forward looking and require estimates of future costs and an understanding of the elements that drive those future costs. Marginal costs are not historic costs because marginal costs are prospective and reflect changes in technology. Also, the impact of inflation causes marginal costs to differ from historical costs.

Q. Please describe Exhibit ___ (JTT-3) and list and briefly describe the schedules presented as part of that Exhibit?

A. Exhibit __ (JTT-3) presents the results of the MCOSS and consists of four schedules:

Schedule 1 – sets forth the calculation of the marginal demand-related distribution costs.

Schedule 2 – sets forth the calculation of the weighted average customer cost.

Schedule 3 – sets forth the calculation of the marginal customer-related distribution costs.

Schedule 4 – sets forth the calculation of the marginal distribution revenue requirement and calculates the Base Rate Energy Charge for the Excelsior Job Program.

Q. Please describe the components of marginal costs that you have determined.

A. A MCOSS estimates the cost of providing an additional unit of service. In this case, service is defined as the basic functions performed by LIPA to provide electric service to its customers. These basic functions are:

1) adding new capacity to the transmission system.
2) adding new capacity to the distribution system.
3) delivering electricity to customers using LIPA's distribution system.

The marginal cost of delivering electricity to LIPA's customers has two cost drivers. The first cost driver is LIPA's obligation to meet its customers' Non-

Coincident Peak ("NCP") demand, and the second cost driver is LIPA's obligation to connect each customer to the distribution system. Therefore, the MCOSS presents both a demand component and a customer component of the marginal cost of distribution.

Q. Please provide an overview of how you calculated the marginal cost of service.

A. The objective of the MCOSS analysis was to quantify the marginal costs LIPA incurs to deliver additional units of load on its electric distribution system and to connect an additional customer. I began by identifying the following two major marginal costs: marginal customer costs and marginal demand or capacity costs.

Marginal customer costs are the additional costs incurred by LIPA to add a customer to the system. These include the capital costs of a service and a meter, as well as the incremental operating, maintenance, and administrative and general expenses. Marginal customer costs are expressed as incremental annual costs per customer.

Marginal demand costs are those additional costs associated with serving an additional unit of demand during the peak period. These marginal costs are the capital costs of adding new transmission and distribution facilities relative to increasing customer demands for electricity. Marginal demand costs are expressed as an incremental annual cost per kW of demand.

Q. What rate classes are included in the MCOSS?

A. The MCOSS included LIPA's main customer service classes. However, it excludes contract and discount customer service classes because these classes would have the same marginal costs as the comparable non-contract or discount service classes. Lighting classes are also excluded because the marginal cost to serve these classes does not affect LIPA's rates. The following is list of service classes and the corresponding rate codes identifying the six customer rate classes presented in the MCOSS:

1. Residential - Non Time of Use ("TOU"): Service Classification No. 1 (Rate Codes: 180, 183, 186, 380, 480, 481);
2. Residential Heat: Service Classification No. 1 (Rate Codes: 580, 581, 880, 881, 882, 883);
3. Residential TOU: Service Classification No. 1-VMRP (Rate Codes: 181, 182,184,188);
4. Small Commercial: Service Classification No. 2 & No. 2-VMRP (Rate Codes 280, 288);
5. Large Commercial: Service Classification No. 2-L & No. 2-H& No. 2LVMRP (Rate Codes 281, 282, 283, 290, 291, 293);
6. Mandatory Large Demand Metered Service with Multiple Rate Periods: Service Classification No. 2-MRP (Rate Codes 284, 285).

The six categories above will be referred to as LIPA's marginal customer rate classes.

Q. Please describe how the marginal cost of additions to LIPA's transmission system was calculated.

A. The marginal cost of additions to the transmission system is driven by LIPA's incremental capacity-related plant investments needed to serve new load. The incremental investment costs associated with transmission were derived from engineering estimates and information that was contained in PSEG LI's capital budget for 2015.

The transmission investment costs include loadings for labor and general plant. The resulting capacity-related investment costs are then escalated to the rate year -- 2016 in this case – using the ten year historical compound annual growth rate as set forth in the Handy-Whitman Transmission Plant index for the North Atlantic region. This calculation resulted in a marginal transmission plant investment cost of $218 per kW as shown on Exhibit __ (JTT-3), Schedule 1 Column C.

Q. Please describe how the marginal cost of additional investment in the primary and secondary distribution systems was calculated.

A. The incremental investment costs associated with the primary and secondary distribution systems were derived from engineering estimates and information that was contained in PSEG LI's Work Management System and the Company's work orders that were established to construct new facilities. This work order information was separated into residential and non-residential rate categories to obtain a rate class-specific estimate of primary and secondary distribution investment costs.

The marginal primary and secondary distribution investment costs include loadings for labor and general plant. The resulting capacity-related investment costs were escalated to the 2016 rate year using a weighting of the Handy-Whitman Index for the various components of the primary and secondary distribution system. The results per kW of demand investment costs are presented on Exhibit __ (JTT-3), Schedule 1 Column D.

Q. Please describe the source of the data for the marginal average transformer investment costs by rate class.

A. The marginal investment costs by rate class for transformers were based on a study of net book value of transformers by type. Each transformer type was assigned to a service classification based on the transformer size and quantity in service. This study was performed instead of a full replacement study due to the fact that customers in various service classifications share transformers. This resulted in the assignment of the net transformer plant balance to each service classification. This allocation of net transformer plant to each marginal customer rate class was then scaled to the total gross plant balance of transformer plant. The total gross plant balance allocated to each marginal customer rate class was then divided by the marginal customer service class's NCP demand to calculate a per kW marginal investment cost. These marginal investment costs were then loaded with general plant and escalated to the 2016 rate year using the appropriate Handy Whitman indices. The resulting marginal investment costs for transformers are presented in Exhibit __ (JTT-3), Schedule 1 Column E.

Q. Please describe the source of the data for the average marginal service investment costs by rate class.

A. The marginal investment costs by rate class for services are the full replacement costs identified by PSEG LI's Work Management System and the Company's work orders for service facilities in 2014. These investment costs were then loaded with labor burdens and general plant and escalated to the 2016 rate year using the appropriate

Handy Whitman indices. The resulting marginal investment costs for services are presented in Exhibit __ (JTT-3), Schedule 3 Column A.

Q. Please describe the source of the data for the marginal meter investment cost by rate class.

A. A special study of meter investment was performed by PSEG LI to obtain the fully loaded cost of a new meter installation based on the typical meter used by each service classification. The new meter costs were then loaded with installation labor, labor burdens and general plant and escalated to the 2016 rate year using the Meter Handy Whitman Index. The resulting marginal investment costs are presented in Exhibit __ (JTT-3), Schedule 3 Column D.

Q. Please describe how the weighted average marginal customer cost was calculated.

A. Marginal customer account and record expenses include the costs associated with meter reading, customer records and assistance, and collections. These expenses were taken from the allocated account balances provided in the embedded cost of service study for the calendar year 2016. These account balances were divided by the total projected number of LIPA customers in 2016 to arrive at a base annual customer cost. The number of customers was adjusted to recognize the relative degree of effort that is required by LIPA to provide customer account services for the different types of customers, (i.e., SC-1 Residential, SC-2 Commercial). This adjustment, which is described more fully below, allows the annual expense to be allocated to customers based on service class. This results in an annual adjusted marginal customer cost of $135 presented in Exhibit __ (JTT-3), Schedule 2.

Q. Please describe how marginal demand-related transmission costs were computed.

A. The marginal demand-related cost component of transmission investments includes the demand related transmission, its associated operating expenses, and general plant loaders escalated to the 2016 rate year. The fully loaded investment costs are then put into annual terms by applying an Economic Carrying Charge Rate ("ECCR") of 11.3 percent, as shown on Exhibit __ (JTT-3), Schedule 1.

Q. Please describe how the ECCR of 11.3 percent for transmission plant was computed.

A. The annual ECCR is the amount, stated as a percent of original cost that will permit recovery of all transmission investment, as well as the corresponding operating and maintenance ("O&M") expenses, insurance and other taxes over the economic life of the asset. The ECCR includes depreciation expense, O&M expenses, property taxes, return and income taxes. These inputs are entered into a model that determines the levelized ECCR. The levelized ECCR is based on an assumed weighted average cost of capital of 4.70 percent, grossed up for debt coverage of (1.35), for the depreciation life of the transmission plant. The ECCR also includes 1.59 percent for O&M costs for transmission plant, which are calculated by dividing transmission O&M costs from the 2016 budget by the transmission gross plant in 2013 adjusted upward to full replacement value. Other inputs to the ECCR calculation are 10.26 percent for insurance and other taxes (i.e., property taxes). These inputs results in a calculated rate of 11.3 percent for the levelized ECCR used in the calculation of the marginal cost of transmission plant.

Q. Please describe how marginal customer-related distribution costs were computed.

A. Exhibit __ (JTT-3), Schedule 3 shows the development of the annual, marginal customer-related distribution cost. This customer cost includes cost components related to services, meters, and customer expenses. The current investment cost for services and meters as described previously is put into annual terms using the ECCR for each respective investment type. The ECCR is determined in a similar manner to the transmission ECCR as described above. The customer expense cost component is based on the adjusted customer cost developed by the ECOSS study in Exhibit __ (JTT-2), Section 4, Schedule D, pages 91 through 102, multiplied by the estimated relative degree of customer account service effort. The sum of the annual customer expenses for services, meters and customer accounts results in the marginal customer-related distribution cost shown in column J of Exhibit __ (JTT-3), Schedule 3.

Q. Please explain how you estimated the relative degree of customer account service effort by rate class.

A. The marginal customer expense adjustment factors shown in Exhibit __ (JTT-3), Schedule 3, Column H were developed using the customer expenses set forth on the total expense line of the ECOSS Customer Records and Collections table, Exhibit __ (JTT-2), Section 4, Schedule D, page 95 (Row 66). There are three residential service classifications in the MCOSS. The costs of these three residential service classifications were summed and then divided by the total number of residential customers to obtain the per-residential customer account cost of $173. For the remaining marginal customer rate classes, the embedded allocation of customer expenses as shown on the total expense line of the ECOSS Customer Records and Collections tab was divided by each service classification's number of customers and compared to the residential customer account cost of $173. The weighting factor is calculated for the non-residential service classifications by dividing their cost results by the residential customer account cost of $173 to obtain non-residential weighting factors.

Q. Please explain why the marginal cost per customer by service class used the embedded costs from the ECOSS.

A. The marginal customer costs for delivery service include the expenses associated with meter reading, billing, customer service, and a variety of other costs. Because of the difficulty of determining the change in customer care costs associated with adding a single customer (other than the cost to print and mail a bill), the MCOSS calculates customer care costs to classes based on the cost of adding a block of new customers to the system. The marginal cost of adding a block of new customers to the system will approach the embedded allocation of costs when the block is large enough to cause investment in new employees and systems to handle the added requirements of the new customers. An example of new employees is the number of employees needed to render bills and customer service representatives needed to serve the new block of customers. An example of systems is new printing and sorting machines to handle the increased number of bills, and new computers purchased to support the new customer service representatives.

Q. Did you calculate a marginal revenue requirement?

A. Yes, the marginal revenue requirement is shown in Exhibit __ (JTT-3), Schedule 4, Column J. The demand-related costs are calculated by multiplying each rate class's NCP by the demand-related marginal investment cost per kW. The customer-related costs are calculated by multiplying the number of customers in each rate class by the customer-related marginal investment cost per customer.

Q. Were the results of the MCOSS used to design delivery rates?

A. Yes. As I mentioned previously, the MCOSS results were used to design rates from the Excelsior Job Program. The rates for participants in this program are based on the incremental cost of serving new load. I propose to set the Excelsior Jobs Programs' Base Energy Charge at $0.0158 per kWh for Service Classification No. 2 - MRP for the incremental load that is added on LIPA's distribution system under the program subsequent to the date of the Empire State Development's ("ESD") approval of the customer's Excelsior Jobs Program certification. No demand charge will be assessed for the customer's incremental load subsequent to the ESD Approval Date for as long as the customer remains in the program.

V. <u>PRINCIPLES OF RATE DESIGN</u>

Q. Please identify the principles of rate design you have applied in developing your proposed rate design.

A. A number of rate design principles or objectives find broad acceptance in regulatory and energy policy literature. These include:

1. Efficiency;
2. Cost-of-service;

3. Value of Service;
4. Stability;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budgets.

These rate design principles draw heavily on the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[1] Each of these principles plays an important role in the recommendations developed in my testimony. Each of these principles is discussed below.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by consumers, fosters efficient expansion of production and delivery capacity, results in efficient capital investment in customer facilities, and allows for the efficient use of existing electric supply and delivery resources. Efficiency benefits consumers by fostering economies of scale that are consistent with the best cost-of-service.

Technical efficiency means that the development of the system is designed and constructed to meet the peak load requirements of customers using the most economic equipment and technology consistent with design standards. Efficiency

[1] Principles of Public Utility Rates, 1961, by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen.

recognizes that load diversity increases as the facilities move further away from the customer.

Q. Please discuss the cost-of-service and value of service principles.

A. These principles each relate to designing rates that recover the total revenue requirement without causing inefficient choices by consumers. The cost-of-service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by embedded cost-of-service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service.

The calculation of a "true" cost-of-service is complicated by the fact that for network industries like the electric industry, the provision of public utility service often involves joint and common costs that must be allocated (rather than directly assigned) to specific customer classes or customer rate classes to develop a full cost-of-service study While a good fully distributed cost-of-service analysis can be performed using principles of cost causation, informed judgment is nonetheless required to perform such a study. A fully distributed cost-of-service study, properly reflecting cost causation principles and employing sound methods provides a reasonable tool for the allocation of the total revenue requirement to customer classes (inter class distribution) and within the customer classes (intra class distribution).

Q. Please discuss the principle of stability.

A. This principle is the proposition that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers in the same class or across different classes of customers. This principle also recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, things like the location, type of meter and service, demand characteristics, size, and a variety of other considerations are often recognized in the design of utility rates to properly distribute the total cost-of-service to and within customer classes.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires that prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. The principle of the balanced budget requires that a rate design permit the utility a reasonable opportunity to recover the allowed revenue requirement based on the cost-of-service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective I previously discussed from the perspective of customer rates.

Q. How are these principles translated into the design of electric rates?

A. The process of developing rates consistent with these principles requires a detailed understanding of all the factors that affect rate design. These factors include:

1. system cost characteristics, such as the embedded customer, demand and energy related costs, by type of service;
2. customer load characteristics such as peak demand, load factor, and quality of service;
3. market considerations, such as elasticity of demand, competitive alternatives and end-use load characteristics; and
4. other considerations, such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of under-utilized facilities, opportunities to offer new services, and the status of competitive alternatives.

In addition, the development of rates must consider existing rates and the customer impact of modifications to the rates.

In each case, a rate design seeks to recover the authorized level of revenue based on the actual billing determinants used to develop the rates. Critical to the rate making process is the requirement that the rates provide an opportunity for LIPA to fully recover its cost of service.

Q. Do the factors discussed above, along with rate design goals such as efficiency, dictate a specific rate design?

A. No. There are a number of rate design forms that may be considered in light of the factors affecting rate design and the underlying goals. Rate design concepts such as declining block rates, flat rates, and many others all have merit. The more fundamental question is whether the rate design promotes efficiency in recovering costs and provides accurate, fair price signals.

VI. PROPOSED REVENUE ALLOCATION AND RATE DESIGN

Q. Please summarize Exhibit __ (JTT-4) that sets forth the proposed revenue allocation, rate design, and bill impacts.

A. Exhibit __ (JTT-4) consists of five schedules and supports the proposed revenue allocation, rate design, and resulting bill impacts for calendar years ("CY") 2016, 2017, and 2018. Where appropriate, these schedules set forth differences in bill impacts for customers in Nassau County and the Rockaways as compared to Suffolk County to account for the impact of the Shoreham Property Tax Settlement Rider and certain applicable sales taxes. These schedules are as follows:

- Schedule 1 of Exhibit __ (JTT-4) summarizes the effects of the proposed revenue allocation and rate design on the forecasted revenues by customer rate class. It shows revenues by customer rate class under present and proposed rates and the dollar and percentage increases that result. Schedule 1 allocates the proposed revenue increase of $72,747,000 as set forth on the revenue requirements exhibit (Exhibit ___ (RRP-1)) minus the increase in the Fuel and Purchased Power Cost Adjustment ("FPPCA") and other pass through charges that will be set independent of delivery rates.
- Schedule 2 presents the service and demand charges by service classification and the calculation of the new Standby Rates based on the Unit Costs analysis from the ECOSS.
- Schedule 3 details the specific delivery rate changes for each rate block for each class for CY 2016 – CY 2018. These changes are discussed in detail below.

- Schedule 4 provides monthly bill comparison tables that show the net impact of the proposed rates at different monthly usage levels for Rate Codes 180, 184, 580, 280, 281, and 285.
- Schedule 5 provides annual bill comparison tables that show the net impact of the proposed rates at different annual usage levels for Rate Codes 180, 184, 580, 280, 281, and 285.
- Schedule 6 provides monthly bill comparison tables based on the total customer bill which includes FPPCA, payments in lieu of taxes ("PILOTS") and other charges but are held constant at different monthly usage levels for Rate Codes 180, 184, 580, 280, 281, and 285. This schedule provides the results based on a total bill for the delivery rate changes.
- Schedule 7 provides the annual version of the bill comparison tables provided in Schedule 6.
- Schedule 8 provides the monthly bill comparison tables based on the total customer bill which includes FPPCA, PILOTS and other charges that are changing at different monthly usage levels for Rate Codes 180, 184, 580, 280, 281, and 285.
- Schedule 9 provides the annual version of the bill comparison tables provided in Schedule 8.

Q. Please describe the basis for the proposed rate design.

A. The fundamental elements of the proposed rate design recognize the need to collect more fixed costs in fixed charges, to provide better price signals based on economically efficient prices, and to promote rate stability and non-discriminatory rates. The proposed rates were designed to be more economically efficient, cost based and non-discriminatory, to promote fairness and avoid undue discrimination by limiting cross-subsidization between customers in the same class.

Q. What guidelines and criteria do you consider important for rate design?

A. As far as practicable, rates should be based on the costs of providing the type and quality of service for each customer rate classification. Therefore, the fully allocated embedded cost of service study provides the foundation for the proposed revenue allocation and rate design. Through an ECOSS, customer, energy, and capacity-related costs are allocated to customer rate classes, assuming a degree of homogeneity within these customer rate classes with respect to load characteristics, size, and/or type and quality of service.

Although average embedded costs determine the overall revenue requirements of the utility, they may not give customers adequate signals with respect to the cost implications of their usage on the overall system. For customers in some customer rate classifications, rates based on average costs may not be competitive with alternative energy sources. This situation results in loss of load to alternate generation sources and increased rates for core customers. To address this problem, value of service pricing is used in some rate designs so that rates are more competitive. Regarding LIPA's rates, this is the case for service class SC-13. Therefore SC-13 will not be receiving a rate increase, and in the rate design, its costs of service and revenues are allocated to others customer classes, providing an offset of costs to other customer classes.

Q. Have you considered factors other than cost of service in the proposed rate design?

A. Yes. I considered ECOSS data limitations, customer impact, the need for continuity and revenue stability, and the interrelationships among the customer rate classes. The proposed rate design has not set each services class's revenue request equal to the exact cost of service as shown in the ECOSS, because this would result in large customer impacts for some customer rate classifications. Instead, the proposed rate design is based on pro rata increases to all Service Classifications, except SC-11, SC-12, and SC-13.

Q. How did you allocate the requested CY 2016 rate increase to each customer rate class?

A. The requested rate increase of $72.7 million dollars is a 2% increase over existing CY 2015 rates. This increase was assigned using the previously described revenue requirement allocator. This calculation is presented in Exhibit __ (JTT-4), Schedule 1.

Q. How did you allocate the requested CY 2017 rate increase to each customer rate class?

A. The requested rate increase of $74.3 million dollars is a 2% increase over existing CY 2016 rates. This increase was assigned using the previously describe revenue requirement allocator. This calculation is presented in Exhibit __ (JTT-4), Schedule 1.

Q. How did you allocate the requested CY 2018 rate increase to each customer rate class?

A. The requested rate increase of $74.3 million dollars is a 2% increase over existing CY 2017 rates. This increase was assigned using the previously describe revenue requirement allocator. This calculation is presented in Exhibit __ (JTT-4), Schedule 1.

Q. Are there additional concerns that influenced the proposed rate design?

A. Yes. The proposed customer charges are intended to make them more reflective of customer-related costs. As noted earlier, customer costs are those costs incurred to connect the customer, provide access to the distribution system and meter the usage delivered to the customer as well as the costs of performing customer service, field service, billing and accounting. As more fully discussed below, the rate design proposed in this Rate Plan takes additional steps toward cost-based rates and increases the proportion of customer-related costs recovered through the customer charge.

Q. Why is it important to recover customer-related costs in the customer charge?

A. The current level of the customer charge for the customer rate classes with an explicit customer charge is far below the fixed costs of providing customer service and access to electricity. The customer charge should be based on the costs associated with the capital recovery of the meter and service costs, plus the expenses associated with meter reading, field services, billing and accounting, and customer service at a minimum. The cost-of-service study calculates the monthly customer costs by customer rate schedule. The current customer charge for residential customers recovers less than 39% of the fixed customer related costs.

When the customer charge is insufficient to recover customer-related costs, the energy rates (i.e., the usage charges) must collect a higher portion of the class's revenue requirement. In fact, only a small portion of the base delivery revenue requirement for each customer rate class relates to energy-related costs. Therefore, the majority of the costs being collected through the usage blocks are fixed costs that are either demand or customer-related. As a result, usage block rates tend to create intra-class cross subsidies because higher volume customers pay more than their fair share of fixed costs and lower volume customers pay less than their fair share of fixed costs. Collecting more costs using fixed charges like the customer charge helps to reduce intra-class cross subsidies. While some subsidization within and between classes is inevitable, rate design should strive to track costs as closely as reasonably possible. A fully cost-based customer charge is a logical, easy to administer, equitable way to ensure this.

Q. To what extent do LIPA's current customer charges recover customer-related costs?

A. This varies by customer rate class and is shown on Schedule 4F of Exhibit __ (JTT-2). As noted, the present Residential customer/service charge of $10.80 recovers only 39 percent of costs that should be included in the customer charge of $27.97 per month. As a result, above average usage customers pay for fixed costs in their energy rates and subsidize the fixed costs of serving below average usage customers.

Q. Are you also proposing to increase the distribution demand charges paid by the service classes that currently pay a demand charge?

A. Yes. The distribution demand charge recognizes that the distribution facilities used to deliver service to the customer must be designed to meet the maximum demand of the customer regardless of when that demand occurs. Charging a larger demand charge will increase fixed cost recovery in line with the incurrence of fixed costs required to provide services. It will also provide the customer service classes that are subject to a demand charge with more stability, and a clearer price signal. Therefore, I am proposing to increase the demand charges paid by Service Classifications 2-L.

Q. Please summarize how the unit cost analysis set forth on Schedule 4F of Exhibit __ (JTT-3) was utilized in the rate design proposals.

A. Exhibit __ (JTT-3), Schedule 4F, sets forth a unit cost analysis by function. The analysis utilizes the functionalized, classified, and allocated expenses for each customer rate class in the ECOSS. The unit cost analysis then inflates the 2016 costs in the ECOSS to the level that reflects the total proposed increase, which approximates the total revenue requirement by service class based on the CY-2018 cost for each component. The unit cost analysis was used in the rate design proposals to calculate the service charges and justify the proposed demand charges. Lastly the unit cost analysis was used to develop the new Standby Rates by customer rate class.

Q. Please describe LIPA's residential service classifications.

A. LIPA presently provides residential service under two service classifications, Service Classification Nos. 1 and 1-VRMP. Service Classification No. 1 is the basic residential service and provides separate rates for customers who use service for space heating (Rate Codes 580, 581, 880, 881, 882, 883), water heating (183, 380), off-peak energy storage (480, 481), and general purposes (180). These services are provided under separate rate codes that I discuss more fully below. LIPA also provides residential service to residential customers under Service Classification No. 1 – VRMP which is a service with multiple rate periods. Customers in this service classification pay "time-of-use" rates that are typically far higher in the period between 10 a.m. and 8 p.m. Daylight Savings Time than they are in other periods.

Q. Please describe the proposed changes to the non-heat residential rate.

A. The residential non-heat rate schedule currently consists of a customer charge and inclining block[2] energy charge in the summer and a declining energy charge in the winter. The residential non-heat rate schedule also currently has certain sub-classes that are differentiated by rate codes that provide for different rates to water heating customers that were on the system prior to January 6, 1983. The residential service classification also maintains certain rate codes that have the same rates as other rate codes. I propose to eliminate rate blocks and the summer and winter season differentiation, which would present a simple to understand flat energy charge. Rate Code 183, which is proposed to and currently has the same rates as Rate Code 180, would be eliminated and its customers transferred to Rate Code 180. I also propose to transfer the customers in the grandfathered water-heating Rate Code 380 to Rate Code 180. For over 30 years, new water heating customers of LIPA have had no rate

[2] Inclining block means rates per unit of consumption are the same over defined blocks of usage, and rates increase for higher consumption blocks.

differentiation from customers without water heating. Discontinuing Rate Code 380 for the approximately 5,000 remaining customers on this grandfathered water heating rate will eliminate rate discrimination that can no longer be justified. The consolidation of rate codes will also simplify the administration of the tariff.

Q. Please describe the proposed changes to the residential heating rate.

A. The heating residential rate schedule currently consists of a customer charge and inclining block energy charge in the summer and a declining energy charge in the winter. I propose to eliminate rate blocks in the summer and extend the existing 250 kWh rate block in the winter to 400 kWh. This would present a simple to understand flat energy charge in the summer and only reduce the energy charge for energy used for heating by heating customer in the winter. I also propose to eliminate Rate Codes 581, 882 and 883 which currently have the same rates as Rate Code 580, and transfer customers under those codes to Rate Code 580. Finally, I propose to transfer the customers in the grandfathered Rate Codes 880 and 881 to Rate Code 580. For over 30 years, these grandfathered heating customers have received a discount compared to current heating customers. This discount to the few remaining customers on this grandfathered heating rate will eliminate rate discrimination that can no longer be justified. In addition, the consolidation of these rate codes would also simplify the administration of the tariff.

Q. What is your rationale for changing the current residential block rates into a flat energy rate?

A. Non–heat Residential customers served under Service Classification No. 1 currently pay, in the summer, a first block rate of $0.0904 for the first 250 kWh and a second block rate of $0.1022 over 250 kWh. In winter they pay a first block rate of $0.0904 for the first 250 kWh and a second block rate of $0.0834 over 250 kWh. So the second block is inclining in the summer and declining in the winter. LIPA's costs to deliver electricity to residential customers – the costs that are recovered through base delivery rates – do not vary between summer and winter in a manner that justifies the current difference in rates. The elimination of these seasonally differentiated rates represents a step in the right direction of sending correct price signals to customers.

Q. Please describe the proposed changes to the residential customer/service charge.

A. Residential customers served under Service Classification No. 1 currently pay a service charge of $0.36 per day, which equates to $10.80 for a billing month of 30 days. I propose to increase this rate to $0.50 per day in 2016, $0.58 per day in 2017 and $0.66 per day in 2018. These values on a monthly basis equate to a $15.00 service charge in CY 2016, moving to a $20.00 dollar service charge in CY 2018. A $20.00 dollar customer/service charge still only recovers 72% of the customer related costs as determined in the ECOSS and is less than the customer charge of other New York electric utilities.

Q. In connection with your proposed changes to the residential customer service charge are you also proposing to adjust the current low income discount?

A. Yes. Currently qualified low income customers pay a service charge of $0.179 per day, which reflects a discount of $0.181 per day for both heat and non-heat residential customers. I propose to increase the low income discount for residential non-heat customers to $0.32 per day and introduce a residential heat low income discount of $0.49 per day.

This proposal increases the low-income discount for residential non-heat customers to $10 to offset the proposed increase in the residential service charge to $15.00. This will completely offset the service charge increase for low-income residential non-heat customers for 2016. The proposed residential heating low-income discount set at $15 dollars is consistent with other utilities in New York and would almost eliminate the service charge completely for those customers in 2016.

Q. Are you proposing any changes in rate design for LIPA's commercial service classes?

A. Yes. I am proposing certain changes for LIPA's large commercial Service Classification No. 2-L. Customers in this Service Classification currently pay rates that consist of a Service Charge per day, a Demand Charge per kW of demand and an Energy Charge per kWh.

Q. Please describe these proposed changes.

A. I propose to increase the demand charges to a charge per monthly kW that recovers approximately 50%[3] of the class' assigned demand revenue requirement. Currently the demand charges only collect 40% of the class' assigned demand revenues. I also propose to change the design of the demand ratchet from 85% in the summer season and 70% in winter season to 85% all year round. This will increase the level of winter demand billing determinants by 12.95%. The change in the winter demand ratchet is appropriate because it removes a non-cost based seasonal difference in delivery rates and it will permit more fixed costs to be recovered through fixed

[3] The COSS would support a much higher demand charge percentage, however applying the concept of gradualism to avoid large individual customer impacts, I am proposing that 50% be used in this Rate Plan.

charges. The rationale for collecting more fixed costs in fix charges is discussed above and these changes, along with increasing the customer charge, will provide customers with:

- more stability by having more cost-based rates;
- increased fairness and less discrimination by reducing intra class subsidies;
- more accurate price signals for high load factor customers.

Q. What is a demand ratchet?

A. To determine the demand levels used to bill customers each month, LIPA first measures the actual as-metered demand, which is the maximum integrated demand during the month. The demand level for each month is set equal to the greater of (i) the actual recorded demand, (ii) 85% of the maximum recorded demand from the months of June through September during the previous eleven months, or (iii) 70% of the maximum recorded demand for the months of October through May during the last eleven months. This measurement is referred to as the demand ratchet. Under my proposal, the demand used for billing purposes in any month will be equal to the greater of the actual recorded demand or 85% of the maximum recorded demand for the last eleven months.

Q. How would your proposal to change the winter demand ratchet from 70% to 85% for Rate Code 281 affect winter demand billing determinants?

A. This proposed change would increase winter demand billing determinants for Rate Class 281 by 12.95%. This percentage was determined by conducting a study of over 48,000 customers currently on Rate Code 281. The study collected the customers' metered demands and calculated the demand billing determinants using the current

70% winter ratchet and then recalculated the demand billing determinants using the proposed 85% ratchet. The winter demand billing determinants were 12.95% higher using the proposed 85% ratchet.

Q. Are you proposing to make rate design changes to the voluntary or mandatory time of use rates charged to the multiple rate period customer classes served under the VRMP Service Classifications?

A. No, not at this time. LIPA's VRMP service classifications provide delivery rate differentials based on time-of-use. Appropriate time-of-use rates should provide for recovery of differences in energy costs in peak and non-peak periods; not differences in delivery costs. LIPA's current billing system does not permit it to bill power supply charges based on time-of-use differences.

Q. Are you making any other proposals that may affect what customers pay?

A. Yes, I propose to add and modify customer rate class transfer clauses.

Q. What are transfer clauses?

A. Transfer clauses set forth the terms through which customers change service classes as their loads change. Transfer clauses permit LIPA to move a customer to a different service classification when the customer's demand or energy usage changes. Currently some customer rate classes have transfer clauses and some do not. We propose to use a uniform set of parameters to adjust all customer service class transfer clauses. Using a single set of parameters will provide customers with more stability, be non-discriminatory and provide LIPA with administrative simplicity. The parameters are:

1) Transfer clause provisions will state that a customer will only be allowed to exit the class if their load falls below 80% of the level identified in the eligibility provision of the service classification.

2) a customer may exit into a lower usage customer service class based on their actual metered demand, provided their demand has been below the threshold identified in item 1, above for the past twelve months; and

3) mandatory customer rate class transfers to a higher usage class will require two consecutive months of measured higher usage or demand, as applicable, to confirm the customer's load level.

Q. What is the justification for each of the parameters?

A. With respect to the first parameter, LIPA has about a 110 thousand commercial customers. If the load parameters that determine eligibility for a class and the load parameters that permit a downward transfer are set at the same load level, there will be a set of customers that may be "bounced" between customer rate classes based on small changes in their loads. This result would be contrary to the goal of achieving stability for our customers and administrative simplicity for LIPA. The solution to this problem is to create a dead-band between the downward transfer load parameters and the eligibility load parameters of the class. My proposal sets the downward transfer clause load parameter at 80% of the size of the eligibility load parameter of the class to prevent customers that are close to the class boundaries from bouncing between customer rate classes.

With respect to the second parameter, it is LIPA's experience that customer loads vary over time. Business loads vary with business cycles. Businesses expand and contract based on their business model and the economy. Therefore we recognize the need for customers to transfer between customer rate classes based on relatively permanent changes in their load requirements. At the same time however, temporary changes in customer usage do not justify inter-class movements. Basing downward transfer clauses on twelve months of actual metered demand for all affected rate classes will ensure that the customers are placed and remain in the correct customer rate class.

With respect to the third parameter, customers' monthly billing determinants can be affected by billing errors, meter reading lag, meter reading errors, estimated bill corrections to actual, and billing delay for various reasons. A report that would review billing determinants to determine which customers should be moved based on a month of data would likely contain false positives for these reasons. The false positives will be substantially reduced if two consecutive months are used to confirm the customer's load level.

Q. Did you perform a study to determine whether customers are currently being served under the appropriate service classification based on the parameters you are proposing to apply to the transfer clauses?

A. Yes. A study was done to identify the customers that would be affected by the changes in the transfer clause provisions described above using billing data through August 2014. The results of this study were used to adjust the billing determinants of the affected customer service classes to reflect implementation of the revised transfer clause parameters in order calculate the CY 2016 proposed rates. The results of the study are set forth on Exhibit ___ (JTT-4), Schedule 3, columns labeled "Customer Rate Transfers." I would proposed to redo this study based on August 2015 data before any customers were notified of their right to transfer down to a smaller service class or were notified that they were going to be place on a higher service class.

Q. Are you proposing any changes in any fees for services assessed by LIPA?

A. Yes. I am proposing:

1. to increase the pole attachment fees assessed under Section IV.C.1 of the General Terms and Conditions of LIPA's tariff to (i) $11.98 per pole, per year, plus applicable amounts in lieu of revenue taxes, for pole attachments by cable television systems and other wire line communication systems, and (ii) to $6.19 for communications systems attachments other than those for wire line communications systems or wireless communications systems, plus the applicable amounts for payments in lieu of revenue taxes;
2. to increase to $100 the No-Access charge assessed when LIPA cannot obtain access to non-residential customers' meters after the requisite number of attempts to read the meter have been made;
3. to establish a Removal Charge of $160 when LIPA is required to disconnect a customer for a second time who has tampered with their facilities or is committing theft of service;
4. to add applicable payments in lieu of revenue taxes to the $20 Uncollectible Payment Handling Charge;
5. to increase the fee for providing certain historical hourly meter reading information from MV90 meters; and
6. a cost based change to maintenance charges included in Service Classifications 11 and 12 for interconnection equipment where LIPA maintains such equipment.

Q. What is the justification for these fee increases?

A. The pole attachment fee for cable television systems and other wire line communication systems are being increased to a level equal to the lowest fee presently charged by an investor-owned utility in New York. This approach has been approved by the PSC as a way to establish pole attachment fees for municipal electric systems. The fees for attachments other than wire line or wireless system attachments are being increased in proportion to the increase in the wire line/cable television system fees.

The No-Access charge is being increased to encourage a reduction in the number of instances in which access cannot be gained to nonresidential customers' meters. The proposed $100 charge is equivalent to the maximum non-residential no-access fee permitted by the PSC.

The Removal Charge is being proposed as a way to deter tampering and theft of service, when a customer without LIPA's knowledge turns on their own electrical service. The fee for historic hourly meter reading data offsets a portion of the cost to process hourly meter data from MV90 meters. Customers' costs for requests for AMI hourly data or their monthly billing determinants from the customer information system are unaffected by this change.

Q. Have you calculated revised maintenance charges for the Service Classification-11?

A. Yes. The revised maintenance charges reflect the cost of maintaining customers' interconnection equipment. The calculation is based on the operation and maintenance expense portion of the marginal cost of distribution plant and is shown on Exhibit ___ (JTT-3), Schedule 1, line 8. This maintenance charges also applies to customers taking service under Service Classification 12.

Q. Have projected revenues associated with the proposed fee revisions been included in the determination of the proposed delivery rates in this case?

A. Yes, this is shown on Exhibit __ (JTT-4), Schedule 1.

VII. STANDBY SERVICE RATES

Q. What is Standby Service?

A. Standby Service is the sale and delivery of electric power:

1. to replace and/or to supplement the power and energy ordinarily generated by a customer by means of a private generating facility on the customer's premises; or
2. for station use by a customer that is a wholesale generator. "Station Use" includes power and energy used by the customer at its premises in connection with its generating facility (a) during periods when such needs are not served by the generator, and (b) to restart the generator after an outage. This service also applies to wholesale generators that require service when their own generating equipment is not sufficient to meet the station loads, provided that such service is not served under a separately-metered account.

Q. Does LIPA presently provide Standby Service to its customers that supply and deliver their own electricity?

A. Yes. LIPA presently has a Service Classification No. 12 which sets forth the terms and conditions under which it provides what it terms "Back-up and Supplemental Service." However, under that Service Classification any customer that requires supplemental service in addition to back-up service may take service and pay the rates that apply under another suitable service classification. The result is that LIPA provides back-up service and supplemental service under a number of service classifications at different rates. In certain cases these rates do not compensate LIPA for the cost of providing Standby Services.

Q. Do you believe that the manner in which Standby Service is provided by LIPA should be changed?

A. Yes. I am proposing to cancel LIPA's current Back-up and Supplemental Service Classification and replace it with a new Standby Service classification. Under my proposal, after a proposed notice and phase-in period, commercial customers that receive Standby Service under Service Classification No. 12 but are billed under Service Classification Nos. 2L, 2H or 2-MRP will be served under the standby service classification for both their back-up and supplemental service requirements unless those supplemental service requirements are separately metered. My standby rate design and tariff proposal is based upon the principles reflected in the "Guidelines for the Designing of Standby Service Rates" that were adopted by the PSC in 2001 in Case 99-E-1470. I have also considered and in many cases incorporated the terms and conditions of the standby service approved by the PSC for Orange and Rockland Utilities, Inc. ("O&R"). Specifically, I am proposing Standby Service rates for customers that include:

1. customer charges that recover the customer-related costs that I have described previously;
2. delivery charges that include (i) fixed contract demand charges, and (ii) daily on-peak "as-used" demand charges;
3. energy charges that recover only the cost of commodity electric supplies; and
4. rates for each commercial service class that will ensure that customers will be responsible for the same delivery costs under standby delivery rates as they would be under their equivalent, non-standby commercial service class.

In addition to these rates, LIPA's Standby Service classification will continue to provide that interconnection charges will be assessed for costs that are more than what LIPA's ordinary costs would have been to supply a customer under a suitable service classification.

Q. How will the level of the fixed contract demand charge and daily as-used demand charge be determined?

A. The fixed contract demand charge will be set equal to the customer's maximum monthly demand during the previous twelve months. For new customers or customers that receive service for less than twelve months before installing new on-site generation equipment, contract demand will be set equal to the service capacity. As-used daily demand charges would be assessed based on the customer's actual maximum daily 15-minute demand on any weekday in which the customer takes delivery service from LIPA during the hours of 12 p.m. to 8 p.m.

Q. Does the allocation of costs included in the proposed Standby Rates tie back to the results of the ECOSS?

A. Yes, as shown in Exhibit ___ (JTT-4), Schedule 2, a study was performed to calculate Standby Rates based on the Unit Cost analysis performed in the ECOSS.

Q. How did you allocate fixed costs between fixed contract demand charges and as-used demand charges?

A. I utilized the allocation approved by the PSC for O&R. The allocation approved therein appears to be reasonable for LIPA.

Q. Are you proposing to implement the proposed Standby Rates for existing customers effective January 1, 2016?

A. No. I recognize that the implementation of the proposed Standby Rates may have a significant impact on current customers. Accordingly, consistent with the principle of gradualism, I am proposing to continue the status quo for current customers through December 31, 2016 in order to give customers as of January 1, 2016 ("grandfathered customers") the opportunity to modify their operations to conform to the revised Standby Rates and terms. Thereafter, I propose to phase-in the impact on grandfathered customers over a five-year period at a rate of 20 percent per year. I have reflected the phase-in of the proposed Standby Rates in the rates and terms of service proposed for CY 2017 and CY 2018.

Q. Do the proposed charges in Standby Service rates affect the rates charged by any other Service Classifications?

A. Yes. The demand charges paid by Standby Service rate customers should also apply to Buy-Back service customers that utilize LIPA's distribution system to deliver power to either other locations on LIPA's system or off-system. Accordingly, I am proposing to change the demand charge for SC-11 distribution customers to $4.25 and $5.20 for secondary and primary voltage, respectively.

VIII. PROOF OF REVENUES

Q. Did you prepare Proofs of Revenue for CY 2016 through CY 2018 that set forth the proposed rates by customer rate class?

A. Yes, a proof of revenue was prepared by year to identify by customer rate class the proposed rates needed to collect each rates schedule's assigned revenue requirement. These rates are presented in Exhibit __ (JTT-4), Schedule 3, which consists of three parts, one for each year from CY 2016 through CY 2018. Schedule 3A for CY 2016 has three groups of columns. The first group is the revenue proof using current rates, the second group uses current rates and identifies the revenues resulting from changes in class billing determinants due to transfer clause changes, and the third group is the proof of revenues showing the resulting rates at the requested revenue requirement. Schedules 3B and 3C provided similar information for CY 2017 and CY 2018, respectively.

IX. PROPOSED DELIVERY SERVICE ADJUSTMENT ("DSA")

Q. Are you proposing any new rate adjustment mechanisms in this proceeding?

A. Yes. I am proposing a new Delivery Service Adjustment mechanism that will permit reconciliation between the amount of certain costs reflected in LIPA's base delivery rates and the actual amount of these costs incurred by LIPA.

Q. What are the cost categories included in base delivery rates that are proposed to be subject to the DSA?

A. The cost categories are:

i. major storm costs;
ii. power supply costs; and
iii. debt service costs.

Q. What are major storms and how are the costs of such storms proposed to be recovered in LIPA's base delivery rates?

A. LIPA uses the same definition of a "major storm" as that set forth in the PSC's regulations, i.e., a "major storm" is a period of adverse weather during which interruptions of service affect at least ten percent of customers and/or result in customers being without service for at least 24 hours. The base delivery rates proposed in this proceeding for major storm costs include recovery of $36.1 million in the first nine-month tracking period and $48.9 million in the subsequent twelve-month tracking period.[4]

Q. What power supply costs are reflected in LIPA's base delivery rates?

A. The proposed base delivery rates reflect power supply costs of $374.2 million in the first nine-month tracking period and $500.2 million in the subsequent twelve-month tracking period. The power supply costs are projected to be incurred (i) under the Power Supply Agreement between National Grid Generation LLC and LIPA, and (ii) as operation and maintenance expenses associated with LIPA's investment in the Nine Mile Point II nuclear facility. These costs are described by the Power Supply Panel.

Q. What debt service costs are reflected in these proposed base delivery rates?

A. The proposed base delivery rates reflect debt service costs of $467.7 million in the first nine-month tracking period and $666.8 million the subsequent twelve-month tracking period. Debt service costs are the interest and principal payments associated with the debt incurred by LIPA adjusted for its debt coverage, plus the cost of the securitized debt. Debt service payments are further discussed in the testimony of LIPA witnesses Kenneth Kane and Thomas Falcone.

[4] In 2016, the tracking period is nine months, January 1, 2016 to September 30, 2016. After September 30, 2016 and beyond, the tracking periods are 12 months, October through September of the following year.

Q. Why is LIPA proposing to recover the difference between the level of major storms, power supply and debt service costs included in base rates and the actual amount of such costs incurred through the DSA?

A. The testimony of Thomas Falcone, LIPA's Chief Financial Officer, explains the need for this rate mechanism.

Q. How will the proposed DSA operate?

A. For each tracking period, the costs incurred in each of the three cost categories will be compared to the corresponding level of costs reflected in base delivery rates for that cost category. For the power supply expenses and debt service, the resulting difference will be credited to or recovered from customers over the twelve months commencing on January 1st of the subsequent calendar year. For major storm costs, a major storm reserve account will be established. There are three possible outcomes for storm costs at the end of each tracking period. First, if actual costs are less than the amount included in rates, the excess recovery will be retained in the reserve account. Second, if actual costs are less than the amount included in rates plus the current balance in the reserve account, the reserve account will be drawn upon to meet the expense. Third, if actual costs are greater than the amount included in rates plus the current balance in the reserve account, one third of the under-recovered amount will be included in the derivation of the DSA rate.

Q. Why will the DSA only recover one-third of the major storm reserve balance?

A. Major storm expenses can be quite variable from year to year, and the recovery rate might be quite large if the entire excess cost of the storms were recovered over a single recovery period. By spreading the recovery over three years, the impact will be smoothed. In addition, a three-year recovery period allows for the possibility that an above-average major storm year could be followed by a below-average major storm year. If this were the case then prior period over-recoveries could be used to offset prior period under-recoveries to reduce the impact on customer bills.

Q. How will the DSA balance be returned to or recovered from customers?

A. The DSA will apply to customers in Service Classifications 1, 1-VMRP, 2, 2-VMRP, 2-L, 2-L-VMRP, 2H, 2-MRP, 5, 7, 7-A, 10, 12 and 16. The DSA balance will be translated into a company-wide DSA percentage based on forecasted delivery revenues for the recovery period (DSA Balance/Applicable Forecasted Delivery Revenue). The DSA recovery charge or credit will be assessed to each applicable customer based on their delivery charges. Over- and under-recoveries of DSA credits or recovery charges also will be tracked and recovered in subsequent recovery periods as well.

Q. Why have you excluded certain service classifications from the operation of the DSA?

A. ESCOs that receive service under Service Classification 14 and Service Classification 11 have been excluded from the DSA because the rates for these services do not include the costs recovered through the DSA. Service Classification No. 13 is not subject to the DSA because the rates paid by these customers are set through negotiations that did not contain a provision for the DSA. Finally, energy delivered under various programs intended to encourage economic development is not subject to the DSA because it is not my intent to modify these programs.

X. OTHER TARIFF MODIFICATIONS

Q. Are you proposing any other tariff modifications in this proceeding?

A. Yes. In addition to the tariff changes that I have already described, I am proposing a number of corrections and clarifications to LIPA's tariff. In many instances these edits are intended to clarify what is stated in the tariff. Certain of these changes also eliminate tariff language that pertains to situations or circumstances that are no longer relevant. In other instances, the changes are intended to provide greater customer service flexibility to enable PSEG LI and LIPA to better serve customers and enhance customer satisfaction. The remaining modifications simply correct typographical or grammatical errors. Exhibit __ (JTT-6) sets forth a comprehensive list of the tariff changes proposed to become effective January 1, 2016 by tariff section and the explanation for each of them.

Q. Did you prepare revised tariff sheets that reflect the rate design and other tariff changes addressed in your testimony?

A. Yes, revised tariff sheets with an effective date of January 1, 2016 were prepared. These proposed tariff sheets are presented in Exhibit __ (JTT-5), Schedule 1 and are set forth in redlined form showing deletions and additions from the proposed April 2015 tariff. Revised tariff sheets with an effective date of January 1, 2017 were also prepared. These proposed tariff sheets are presented in Exhibit __ (JTT-5), Schedule 2. Finally, proposed tariff sheets with an effective date of January 1, 2018 were prepared. These proposed tariff sheets are presented in Exhibit __ (JTT-5), Schedule 3. Schedule 2 and Schedule 3 are set forth in redlined form showing deletions and additions from the previous schedule. The proposed tariff leaves included in Schedules 2 and 3 of Exhibit __ (JTT-5) reflect only changes in rates.

Q. Do your proposed tariff leaves account for proposals that are currently pending before the LIPA Board of Trustees?

A. Yes. The tariff sheets on which I show the proposed changes with an effective date of January 1, 2016 include changes that are pending before, but have not yet been approved by, LIPA's Board of Trustees outside this proceeding. If the Board of Trustees makes any changes to the pending proposal, they will be reflected when we make a compliance filing to update the tariff for all changes ultimately approved by the Board of Trustees.

Q. What have you assumed with regard to the tariff proposal that is expected to be presented to LIPA's Board of Trustees in March 2015?

A. LIPA's staff issued a proposal to change LIPA's Tariff to conform to the recommendations included in LIPA's approved budget for 2015 that is scheduled for presentation to the Trustees at their March 2015 Board meeting. The proposal recommends changes to the LIPA Tariff for Electric Service that would (1) update Delivery Charges consistent with the approved LIPA budget for 2015; (2) authorize the reconciliation of revenue to be recovered through the Energy Efficiency Cost Recovery Rate; and (3) introduce a Revenue Decoupling Mechanism. For the purpose of preparing our proposed tariff leaves, we have assumed that the Trustees will adopt the proposal in its entirety.

XI. LI-CHOICE ISSUES

Q. Does LIPA presently have a retail choice program?

A. Yes. As I noted previously, the retail choice program is known as LI-Choice. The terms and conditions of the program are set forth in Service Classification 14 of LIPA's tariff. At this time, LIPA has approximately 4,300 retail choice customers.

Q. Is PSEG LI proposing any changes to LIPA's LI-Choice program?

A. We are proposing certain limited changes to the tariff provisions governing retail choice to conform those provisions to the manner in which the program actually operates. For example, the tariff contains references to a single-bill option that LIPA is unable to offer at this time. So we are proposing to remove the single bill option.

Q. Does PSEG LI believe that a collaborative should be convened to examine the LI-Choice program?

A. Yes. As discussed in the Power Supply Panel's testimony, there is essentially no merchant power development activity and no competitive wholesale power market in LIPA's service territory. The absence of such a market impedes the viability of retail choice programs in LIPA's service territory. The development of a more robust retail choice program requires consideration of numerous capacity assignment, cost recovery, rate, service and tariff issues. PSEG LI only recently assumed responsibility for LIPA's system in 2014 and we have not yet had the opportunity to consider retail choice-related issues in depth. To begin a discussion of these issues we propose to convene a collaborative process to examine retail choice-related issues. Participants in the process would include representatives of PSEG LI and LIPA, DPS , marketers, consumer groups and other interested parties. Through the collaborative process, we hope to identify retail choice-related issues and develop a widely supported resolution of those issues.

XII. SUMMARY OF RECOMMENDATIONS

Q. Please summarize the major recommendations that you presented in this testimony?

A. My testimony supports a number of changes to LIPA's rate design.

1. Increase the amount of revenues collected through fixed charges. This has the benefits of balancing the utility's budgets and minimizing intra class subsides.
2. Increase the customer charges for all customer rate classes to align the customer-related costs that I have described previously with the way in which customer costs are collected, while also increasing the low-income discount to mitigate the impact of this change on low income customers.
3. Make rate design changes to minimize intra class cross-subsidies. This efficiency change results from a superior alignment of the cost-of-service and rate design for the utility.
4. Modify LIPA's Standby Service rate classifications to conform more closely to PSC policy.
5. Establish a new Delivery Service Adjustment to keep LIPA and its customers whole for differences between the level of certain significant costs recovered in base delivery rates and the amount actually incurred.
6. Convene a collaborative to address retail choice issues.

Q. Does that conclude your pre-filed testimony?

A. Yes, it does.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-00262

REBUTTAL TESTIMONY OF
JOSEPH TRAINOR
ON
COST OF SERVICE, RATE DESIGN,
AND TARIFF ISSUES

Date: June 10, 2015

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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Mr. Trainor, please state your name and business address.

A. My name is Joseph T. Trainor. My business address is 175 E. Old Country Road, Hicksville, NY 11801.

Q. Are you the same Joseph Trainor who previously submitted direct testimony before the Department of Public Service ("DPS") in this proceeding?

A. Yes. I previously submitted Direct Testimony in this proceeding concerning cost of service, rate design and tariff issues on behalf of PSEG Long Island LLC ("PSEG LI").

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to the testimony and recommendations of the Department of Public Service ("DPS") Rates Panel ("Rates Panel"), the DPS Delivery Service Adjustment and Storm Reserve Panel ("DSA Panel"), DPS Customer Service Panel ("Customer Service Panel"), the DPS Energy Efficiency and Rev Panel ("EE_Rev Panel") and the Rebuttal Testimony of Jackson Morris On Behalf of Natural Resources Defense Council ("NRDC").

Q. Besides responding to the direct testimony of other parties, does your rebuttal testimony provide any updates to information previously submitted in this proceeding?

A. Yes, as part of the three-year rate plan proposal being submitted by PSEG LI on behalf of the Long Island Power Authority ("LIPA"), my rebuttal testimony provides the following information as a result of updates to the revenue requirement and PSEG LI/LIPA's agreement to reflect in its three-year rate plan certain adjustments that were recommended by other parties in their direct testimony:

1. A revised forecast of total operating revenues for the twelve months ending December 31, 2016 ("CY 2016"), December 31, 2017 ("CY 2017"), and December 31, 2018 ("CY 2018");
2. Revised proposed rates for each service classification under LIPA's tariff for electric service;
3. Revised bill impacts from current rates to proposed rates for 2016, 2017 and 2018;
4. Revised changes in LIPA's tariff due to rate changes and other tariff changes as described more fully below.
5. A discussion of net metering issues raised by the New York State Public Service Commission's ("Commission") order dated December 15, 2014 in Case 14-E-0151 and 14-E-0422 and a proposal to make a compliance filing to address certain issues related to net metering.

Q. Do you sponsor any exhibits as part of your rebuttal testimony?

A. Yes. I sponsor the following exhibits which were prepared and /or compiled under my supervision and direction:

(i) Exhibit ___ (JTT-8): DPS Information Request Responses;
(ii) Exhibit ___ (JTT-9): Customer Charges assessed by other New York Investor-Owned Utilities;
(iii) Exhibit ___ (JTT-10): Letter from the Leisure Village Board of Directors;
(v) Exhibit ___ (JTT-11): Revised Rate Design and Bill Impact statements;
(vi) Exhibit ___ (JTT-12): Revised tariff leaves; and
(vii) Exhibit ___ (JTT-13): List of proposed Tariff changes.

Q. Do you refer to, or otherwise rely upon, any information obtained during the discovery?

A. Yes. I will refer to certain Information Request responses, referred to as IRs, provided by the DPS. These responses are included in Exhibit___ (JTT-8).

Q. Please summarize the findings and recommendations of the Rates Panel that you will be addressing, and what your conclusions are.

A. I will be addressing the following issues/recommendations discussed by the Rates Panel, and I reach the conclusions summarized here:

1. The Rates Panel recommends (at 10-11) that the Residential and Small Commercial customer charges proposed by PSEG LI be rejected and that this issue be revisited after the issuance of an order in the REV Track 2 proceeding. I disagree, and recommend that customer charges be set at levels consistent with Commission precedent for the rest of New York State. It is not clear at this time how customer charge issues may be addressed in the REV 2 proceeding.
2. The Rates Panel recommends (at 11) that the residential water heating rate be eliminated over a five year phase-out period for rate impact reasons rather than in one year as proposed by PSEG LI. I disagree; LIPA's grandfathered residential water heating rate should be phased out over a three-year rate period, not five. Because this proceeding involves consideration of a three-year rate plan, any phase-out period beyond the three-years may not have a proper revenue neutral mechanism to be implemented and/or be complicated by future changes in rates.
3. The Rates Panel recommends (at 11) a phase-out of residential electric space heating rates over five years. I disagree; Staff's proposal is not cost justified and will result in significant increases in the total costs paid by residential electric space heating customers. Staff's proposal would be inconsistent with PSEG LI's efforts to enhance customer service and satisfaction.

4. The Rates Panel recommends (at 12) that PSEG LI's proposal to eliminate inclining block energy rates in the summer should be rejected. While it may be DPS policy to increase block rates in the summer to encourage customers to use less energy, application of this policy in this case would be unduly burdensome to customers and it is not cost justified. Moreover, it does not really work; the price signal that the Rates Panel wishes to send is not received directly by approximately half the intended customers, who are on balanced billing and are therefore indifferent to seasonal rate changes.
5. The Rates Panel recommends (at 12) that PSEG LI's proposal to eliminate seasonal demand rates and voltage differentials for Large Commercial customers be rejected. This recommendation is not supported by the Rates Panel's purported cost justification. LIPA's T&D system is sized to meet maximum one hour summer load/demand. Delivery energy charges are established to collect the total delivery revenue requirement over annual periods, and the delivery revenue requirement attributable to the summer is no different than the delivery revenue requirement attributable to the other three seasons of the year. Moreover, contrary to the Rates Panel's claim, PSEG LI is not proposing to eliminate voltage differentials for large commercial customers.
6. The Rates Panel recommends (at 10) that PSEG LI's proposal to increase the winter demand ratchet for large commercial customers based on "bill impacts" be rejected. This recommendation is based on a misunderstanding of the impact of the proposal. The 12.95% factor is not a bill impact. Rather, it reflects the

increase to the number of demand billing determinants. Increasing demand billing determinants has the effect of spreading demand costs throughout the year, but it does not materially increase the annual costs of customers subject to the demand ratchet.

7. The Rates Panel's proposal (at 11-12) to increase the customer charge and demand charge for large commercial demand ("Rate Code 281") customers by 11% in each of the three years of the rate plan is acceptable.

8. The Rates Panel's proposal (at 13) that LIPA develop a voluntary Critical Peak Pricing rate schedule that is REV-like, for the largest commercial customers, should wait for the results of REV. The proposal is not practical given the need to evaluate the information technology, billing process, metering, and value proposition that would be required to implement this new rate design in the very short timeframe of this rate plan proceeding.

9. The Rates Panel's recommendation (at 13) that PSEG LI wait for the Commission's REV proceeding to establish a new Standby service is acceptable. The rest of the state already has similar standby tariffs to those proposed by PSEG LI, and PSEG LI believes that moving closer to those statewide policies will facilitate our participation in REV. However, the Rates Panel raises some concerns in that regard and I look forward to working through this issue with them.

Q. Please summarize the recommendations of the DSA Panel that you will address, and your conclusions on those issues.

A. I will address the DSA Panel's recommendation (at 34-36) that the storm reserve be capped at no more than 1.5 times the expense amount included in base delivery rates each year. I recommend that the DSA Panel's proposal be modified to set the storm reserve to $75.0 million, as proposed by Mr. Falcone, the Chief Financial Officer of LIPA.

Q. Please summarize the recommendations of the Customer Service Panel that you will address, and your conclusions.

A. I will address the Customer Service Panel's recommendations (at 18-19, 22-23) that (i) the low income discount for non-heat residential customers not be increased, and (ii) PSEG LI's proposal to charge a Removal Charge when PSEG LI is required to disconnect a customer for a second time due to that customer's tampering with LIPA's facilities be rejected. I continue to recommend that the residential customer charge for non-heat residential customers be increased. Therefore, I also continue to recommend that the low income discount for non-heat residential customers be increased. With respect to the proposed Removal Charge, if the Customer Service Panel's recommendation to reject the Removal Charge is adopted, then the language of LIPA's tariff on Leaf 154 should be explicitly modified to permit LIPA to recoup the cost of a second turn-off of service. As part of Exhibit __ (JTT-12) I am including proposed tariff language to address this issue.

Q. Please summarize the recommendations of the EE_Rev Panel that you address, and your conclusions.

A. I propose to implement a change to delivery rates to address the EE_Rev Panel's recommendation (at 12-13) that labor and associated benefits costs associated with energy efficiency programs should be recovered in distribution rates. As discussed by the Utility 2.0 Panel in its rebuttal testimony, to effectuate this recommendation delivery rates will be increased to collect an additional $5.57 million dollars in 2016 and the Energy Efficiency Rider will be adjusted downward by the corresponding amount in 2016. Exhibit ___ (JTT-11)-Sch1, page 1 of 1 identifies the change to delivery rates associated with the implementation of this proposal in all three years of the rate plan.

Q. Please summarize the recommendations of the Rebuttal Testimony of Jackson Morris On Behalf of NRDC that you address, and your conclusions.

A I will address Mr. Morris's recommendations (at 2-3) that support the DPS's recommendation not to change the residential and small commercial customer charges due to (i) the allegedly negative effect on low income customers, and (ii) the allegedly negative effect on energy efficiency. Mr. Morris' claims lack merit because (i) he ignores the fact that PSEG LI proposed to address the impact of the proposed customer charge increases on low income customers through modification to the low income discount, (ii) there is no reason to believe that energy rates will adversely affect the payback of energy efficiency investments because the energy rates PSEG LI is proposing are very close to the present energy rates, and (iii) the exhibits attached to Mr. Morris' testimony support a $20 minimum bill charge, which is actually in alignment with PSEG LI's proposed increase in the customer charge.

II. ECOSS & MCOSS METHODOLOGY

Q. Did you submit an Embedded Cost of Service Study and a Marginal Cost of Service Study in this proceeding and were they reviewed by the Rates Panel?

A. Yes. I submitted both an Embedded Cost of Service Study ("ECOSS") and a Marginal Cost of Service Study ("MCOSS") in this proceeding and they were reviewed by the Rates Panel.

Q. Did the Rates Panel identify any specific issue with the ECOSS or MCOSS?

A. Yes, they identified that PSEG LI ECOSS and MCOSS used a forecasted test year instead of a historical test year.

Q. Besides the test year issue, did the Rates Panel take issue with any other aspect of the ECOSS or MCOSS?

A. No, they did not cite any specific issues with the ECOSS or MCOSS.

Q. Did the Rates Panel identify any issues with the calculations of the Embedded or Marginal customer costs presented in the Embedded or Marginal Costs?

A. No, they did not identify any specific issues with the performance, calculations or the cost allocations in the ECOSS or MCOSS.

III. RATE DESIGN

A. Residential and Small Commercial Customer Service Charge

Q. What reason did the Rates Panel's provide for proposing to keep LIPA's residential and small commercial customer charges at current levels?

A. The Rates Panel cited the alleged bill impacts of PSEG LI's proposal as the primary basis for its recommendation. However, in making this claim, the Rates Panel appears to have ignored PSEG LI's proposal to change the customer charge in three steps over the three-year rate plan. The Rates Panel identifies the magnitude of the three-year changes as if it is a one-time adjustment and ignores the annual bill impact. PSEG LI's proposal is intended to ameliorate customer impacts by implementing a phase-in of the residential customer charge increase, producing an increase over three years that moves only approximately halfway to a cost based customer charge (i.e., the current customer charge is $10, a cost based customer charge is approximately $30, PSEG LI proposes to move to $20 over three years). In addition, the Rates Panel alleges that PSEG LI "proposes to increase residential and small commercial customer charges by 100% and 300%, respectively," increases that are, allegedly, "substantially greater than the overall requested delivery rate increase of approximately 4%" (page 15, lines 1-10). However, it should be clear that a 100%/300% increase in customer charges does not equate to similar percentage increases in residential and small commercial customers' overall delivery charges. The customer charge proposal for 2016 is $15 dollars a month. The average increase for the average usage customer on a total bill basis (including the associated lower energy charge) is approximately $2.85 per month. If a customer has no usage, the increase is $5.00 per month, or $2.15 a month more than the average customer. If a customer has low usage, (i.e., 280 kWh per month) the increase is $3.64 per month or $0.79 a month more than the average usage customer. This equals approximately $10 dollars per year.

Q. In your opinion is a bill impact of an additional $10 dollars a year on residential low usage customers reasonable?

A. Yes. The Commission has approved increases in customer charges that are intended to move those charges closer to cost-based levels. Exhibit__ (JTT-9) contains the residential and small commercial customer charges assessed by electric IOUs in New York State. These residential and small commercial customer charges were approved as part of joint proposals supported by the DPS. The Rates Panel has not provided a persuasive reason why LIPA should be required to retain customer charges that are far below those assessed by New York's IOUs.

Q. Why do you believe that the bill impacts identified by the Rates Panel do not justify retaining the current residential and small commercial customer charges?

A. The Rates Panel has not quantified what bill impact is too high, it has not defined a low usage customer, it has not identified the number of low usage customers for which the impact is too high, and it has not provided any parameters as to what bill impact would be appropriate. The Rates Panel is contending that anything greater than a customer-charge related bill impact of 0% is unreasonable, but this testimony cannot be squared with the fact that DPS Staff has supported increases in the residential and small commercial customer charges assessed by a number of Investor-Owned Utilities ("IOUs") in New York in recent years.

Q. Is there anything else wrong with the Rates Panel's claims that bill impacts justify keeping the residential and small commercial customer charges at current levels?

A. Yes. By proposing to not change the residential and small commercial customer charges in this proceeding, the Rates Panel is setting up a situation in which customer charges will need to be dramatically increased in the future to achieve cost-based charges, which would entail larger low usage customer bill impacts than PSEG LI is currently proposing. The Rates Panel ignores the fact that PSEG LI's proposal is designed to gradually move LIPA's residential and small commercial customer charges to a level that is approximately 50% of a cost-based charge over a three-year period.

Q. Did the Rates Panel identify any other reason to keep the residential and small commercial customer charges at current levels?

A. The Rates Panel also stated (at 16-17) that PSEG LI/LIPA should wait to address customer charges because REV Track 2 "is expected to include a full examination of the current rate structures and designs."

Q. Do you agree that a change to the customer charges should wait for REV Track 2?

A. No. It is my understanding that Rev Track 2 is considering ways to revise energy and power markets. I am not aware of any Rev Track 2 orders or specific proposals that propose changes in the method for calculating residential and small commercial customer charges. Exhibit__ (JTT-8) contains the DPS's response to a PSEG LI Information Request in which the DPS fails to identify any Rev Track 2 orders or specific proposals that propose changes in the methods for calculating residential and small commercial customer charges. The response points only to an open ended question to stakeholders without the stakeholders' responses indicating that customer charges should be addressed in Rev Track 2. Therefore, the Rates Panels' argument for holding off changing the residential and commercial customer charge until Rev Track 2 proposals are complete should be rejected.

Q. What reason did Mr. Morris provide for proposing to keep LIPA's residential and small commercial customer charges at current levels?

A Mr. Morris recommends no change to the residential and small commercial customers' charges due to (i) the alleged negative effect of such charges on low income customers, and (ii) the alleged negative effect of such charges on energy efficiency.

Q. Do you agree with Mr. Morris's rationale?

A No. Contrary to Mr. Morris' claim, PSEG LI has addressed the impact of its proposed changes in customer charges by proposing to increase the low income discount. In addition, Mr. Morris's further claim that current investors in energy efficiency might see a change to the payback period is invalid because the proposed residential energy rates after adjustment for the rate request are nearly identical to the current energy rates, even with the proposed increases in the customer charges. In addition, while Mr. Morris provides two papers to support his position on energy efficiency concerns with the customer charge, these papers provide an alternative to the customer charge referred to as a "minimum bill". Although Mr. Morris is not proposing a minimum bill, the justification for a minimum bill as described in the exhibit is similar to the justification for an increased customer charge. Both an increase in customer charge and a minimum bill are intended to ensure that customers pay an appropriate share of the costs incurred to serve them.

Q. What is the difference between a customer charge and a minimum bill?

A. The only difference is that a minimum bill usually allows a customer to receive some relatively small delivery quantity. If the customer's actual usage in the month is not equal to or greater than that quantity, the customer must still pay the minimum bill.

Q. Can you summarize the most important arguments for increasing customer charges?

A. Yes. Prior Commission decisions recognize that customer charges that are substantially below cost create a subsidy and burden imposed on other customers by low use customers. Moreover, increases in customer charges will better align LIPA's rates to more accurately recover its fixed costs. Conversely, residential energy rates proposed by the Rates Panel would be the highest in the New York State because the proposed customer charge would be approximately $10 a month or half the average customer charge for the other IOUs in the State. When the customer charge is insufficient to recover customer-related costs, the energy rates (i.e., the usage charges) must collect a higher portion of the class revenue requirement. However, only a small portion of the base delivery revenue requirement for each customer rate class represents energy-related costs. Therefore, the majority of the costs being collected through the usage blocks are fixed costs that are either demand or customer-related. As a result, usage block rates tend to create intra-class cross subsidies because higher volume customers pay more than their fair share of fixed costs and lower volume customers pay less than their fair share of fixed costs. Collecting more costs using fixed charges like the customer charge helps to reduce intra-class cross subsidies. While some subsidies within and between classes are inevitable, rate design should strive to track costs as closely as reasonably possible. This is why it has been the Commission's policy to approve customer charges that move toward cost based charges.

B. Residential Water And Space Heating Rates

Q. Does the Rates Panel agree with PSEG LI that the grandfathered residential water heating rate should be eliminated?

A. Yes, however, the Rates Panel proposal is to the grandfather the residential water heating rate class for five years.

Q. Do you agree with the Rates Panel's proposal to phase-out the grandfathered residential water heating rate class over five years?

A. No.

Q. Do you have an alternate proposal to phase-out the grandfathered residential water-heating rate class?

A. Yes, I propose to limit the phase-out to the three years of the rate plan. This mitigates the bill impacts identified by the Rates Panel, but limits the phase-out to the term of the rate plan. I propose a three year phase-out so that the full impact of the change can be captured during the existing rate plan.

Q. What would be the bill impact if your alternate proposal to phase-out the grandfathered residential water-heating rate class was used?

A. Using the PSEG LI filed rate request, the delivery revenues for Rate 380 – the water heating rate class – will be increased by under 6.3% per year on average. This is shown on Exhibit___(JTT-11) Schedule 3A and 3B, Page 3 of 18, line 39.

Q. Does the Rates Panel also propose to eliminate the residential electric space heating rates?

A. Yes, the Rates Panel proposes to eliminate electric residential space heating rates over five years.

Q. Does the Rates Panel identify the bill impacts of this new proposal to eliminate the residential electric spacing heating rates?

A. No, however it does state:

> in the first year would result in an increase of 54%. To mitigate these effects, we recommend the gradual elimination of the space heating discount over a five year period, which results in above average annual increases of approximately 12% to the space heating rate block.

The 54% and 12% are references to the increase in the tail block rate only. These references do not represent the bill impacts on a typical residential electric heat bill for the full change. I calculated the total bill impact using the Rates Panel's calculated delivery rates for residential non-heat as compared to current electric heat delivery rates. Table 1 identifies the bill impacts on the delivery portion of the bill based on the Rates Panel's fully phased-in delivery rate proposal.

Table 1
Bill Impact Assuming DPS Rates Panel's Electric Space Heating Proposal
Current Space Heating Rates vs 2018 Non Space Heating Rates

			Delivery			
	Total Annual KWH Usage		Present	Proposed	Difference	Change
1	**7,000**		$711.81	$823.39	$111.57	15.67%
2	**10,000**		$922.63	$1,128.26	$205.63	22.29%
3*	**11,800**		$1,049.30	$1,311.43	$262.13	24.98%
4	**15,500**		$1,308.84	$1,686.73	$377.89	28.87%
5	**21,600**		$1,737.14	$2,306.21	$569.06	32.76%
6	**31,600**		$2,439.14	$3,321.37	$882.23	36.17%
7	**41,600**		$3,141.13	$4,336.53	$1,195.40	38.06%
	*Average					

Q. Do you agree with the Rates Panel's proposal to phase-out residential electric space heating?

A. No. PSEG LI disagrees with this proposal because it will result in rates that far exceed the marginal costs to serve these customers and will substantially increase the winter bills of these residential customers that are already paying the highest winter bills. This proposal would be unreasonably burdensome to our residential electric space heating customers.

Q. Please explain why you believe that the Rates Panel's proposal would "far exceed marginal costs."

A. For the vast majority of residential customers, the cost to serve is nearly the same. Most residential customers have the same size meter, service length and transmission cost. They also cause LIPA to incur the same call center, collection, meter reading and billing costs.

The costs I have just listed are primarily recovered in the energy portion of residential distribution rates, and are all utility costs that do not vary based on the amount of energy a residential customer uses in the winter. In other words, the marginal cost to serve a residential customer in the winter with the next unit of energy is negligible when fuel is excluded from the rate. Therefore, charging residential space heating customers' increased delivery rates for their spacing heating usage will result in rates that will far exceed marginal costs.

Q. How much does a typical residential electric space heating customer currently pay?

A. A typical electric heating customer uses about 2,735 kWh per winter month, while a non-electric heating customer uses about 864 kWh per winter month. This equates to a delivery bill of about $181 dollars before taxes and other charges for an electric heating customer as compared to $85 dollars before taxes and other charges for a typical non-electric heating customer. The additional delivery costs based on the relatively high usage required by electric heating as the winter months have a significant impact on our electric heating customers. As an example please see the letter received from the Leisure Village Board of Directors presented in Exhibit___ (JTT-10).

Q. Why do you believe the Rates Panel's electric space heating proposal would be unreasonably burdensome for customers?

A. The Rates Panel's proposal would increase the typical electric heating customer's winter month electric delivery bill by approximately $81 per month if the change were calculated using current rates without a declining block. The Rates Panel's proposal to eliminate residential electric heating cites an average total bill change of 14% on Exhibit__ (SRP-3), page 2 of 5. This is incorrect; once the Rates Panel's proposed total rate is applied, the total average delivery bill would be increased by 25% as identified in Table 1[1]. The 25% compares to the total bill delivery impact using the Rates Panel's calculated rates for residential non-heat as compared to current electric heat rates.

I believe that an increase of approximately $81 or 44% per winter month before consideration of the rate increase proposed by PSEG LI/LIPA in this case would be unduly burdensome.

Q. Please explain how you determined that the Rates Panel's electric heating proposal would increase a typical electric heating customer's delivery bill by $81 per winter month.

A. I performed a study that looked at electric heating customers that had average summer usage of 1,000-1,100 kWh per month and then looked at their average winter usage. The average for the electric heating sub-group in the winter was 2,735 kWh. I performed a similar study that looked at non-electric heating customers that had average summer usage of 1,000-1,100 kWh per month and then looked at their average winter usage. The average for the non-electric heating subgroup in the winter was 864 kWh.

[1] Table 1 is calculated using the Rates Panel's calculated rates and assumes a total rate plan increase of 2%. Therefore, the 17% increase for residential electric heat should be compared to 2% and not PSEG LI's original requested increase of 6% over three years.

Using the current residential space heating electric rate of:

1) Customer charge of $10
2) First 250 kWh: 0.0921 per kWh
3) Next 150 kWh:$0.0851 per kWh
4) All Other kWh:$0.0579 per kWh,

I calculated a bill impact of an additional $81 per winter month. The calculation is as follows:

Current Space Heating rates with declining block rates:

$10 + (250*$0.0921+150*$0.0851+2,335*$0.0579) = $182

Rate Panel Proposed Space Heating without declining block rates:

$10 + (2,735*$0.0921) = $263

Q. Do you have any comments concerning the Rates Panel's assertion that no other IOUs in New York have electric heating rates?

A. The Rates Panel is correct that no other New York IOUs have electric heating rates. However, electric heating is much more prevalent in areas with milder temperatures, such as the Mid-Atlantic and the South. Long Island's weather is not like upstate New York's. Long Island's winter temperatures are more like the Mid-Atlantic region's temperatures, making electric heating a more viable option for residential customers. Currently, LIPA has approximately 42,000 electric space heating customers. This number of customers with electric heat justifies the continuation of LIPA's electric heating rates. Therefore, the Rates Panel proposal to eliminate the electric heating discount should be rejected.

C. Seasonal Rates

Q. The Rates Panel identifies various modifications to PSEG LI's proposed rate design based on its assertion that seasonality should be reflected in the delivery rate design; can you summarize those proposed modifications?

A. Yes. The Rates Panel recommends rejection of PSEG LI's proposals to eliminate (i) residential inclining block rates in the summer, and (ii) seasonally different commercial energy and demand rates.

Q. What is the Rates Panel's argument for seasonal delivery rates?

A. The Rates Panel's argument for seasonal delivery rates is based on the fact that a significant focus of the design of LIPA's T&D system is to ensure it complies with design criteria at projected summer peak demand. The Rates Panel claims that because this is a major consideration of the design and construction of T&D facilities, it should be reflected in summer rates. Moreover, the Rates Panel claims that decreasing summer tail block rates would send a "wrong" price signal that would encourage peak load growth.

Q. Do you agree with the Rates Panel's cost based seasonality arguments?

A. No, not for delivery rates. Delivery rates collect delivery costs, which are mainly fixed costs. These fixed costs do not vary materially with the time of year or the seasons. They are primarily labor, maintenance costs and debt service on utility assets. In LIPA's case, there is also a very significant tax burden, which is not "seasonal." Many of these costs have a flat run rate throughout the year and there is no need to have rates that are higher in the summer when customers are already receiving high summer bills based on usage.

The T&D system is sized for the maximum system or customer load, which is measured over an hour or a 15-minute interval and not a whole season. This one hour cost driver is considered in the embedded cost of service study and is used to set the rate classes' revenue requirements, not their rate designs. The primary cost incurred by a utility to meet peak load is debt service which is a flat, mortgage type cost incurred throughout the year. The suggestion that summer rates should be higher to recover an hourly cost driver is not persuasive.

Q. Does the Rates Panel's price signal-based seasonality argument justify the retention of higher delivery rates in the summer?

A. No. I do not disagree that higher summer delivery rates may discourage some consumption. However, electric bills in the summer can be two to three times larger than other monthly bills based solely on usage and LIPA's customers are already overburdened by their summer utility bills. In addition, LIPA offers balanced billing, which eliminates the price signal associated with higher summertime delivery rates for half of LIPA's customers. So, economic theory aside, on balance, from both an equitable and practical standpoint, I believe that continuing to maintain inclining block rates in the summer is not justified.

Q. The Rates Panel cites a 12.95% bill impact on winter demand charges as the basis for rejecting PSEG LI's proposed change to the winter demand ratchet; is that correct?

A. No, on an annual basis the demand ratchet change will have a minimal impact on individual customers' bills. The percentage identified by the Rates Panel represents the increase in the amount of demand billing units. This increase in billing units will lower the per unit demand rate, it will not increase any customer's delivery bill by 12.95%.

Q. Is the Rates Panel's position on the Winter Demand Ratchet counter to its arguments for retaining seasonal rate differentials?

A. Yes. The Rates Panel states that rates should be seasonal due to the fact that the T&D System is sized to meet the maximum summer load. As I stated earlier, this is a maximum hour condition and does not provide a basis for seasonal delivery energy or demand rates because rates should be designed to recover the annual revenue requirement. However, the demand ratchet links a customer's maximum load, which normally occurs in the summer, to the costs that the customer's maximum load imposes on the system (i.e., transmission and transformer costs). The only difference between the current ratchet and PSEG LI's proposed ratchet is that under PSEG LI's proposal, the ratchet value (i.e., 85%) is held constant throughout the year. This does not materially change any customer's annual costs, but it better aligns the system's costs with the charges the customers receive to use the T&D system over all months, instead of reflecting more of that cost in customers' summer bills.

Q. Why is it important to remove seasonality from delivery rates?

A. The elimination of seasonally differentiated rates represents a step in the right direction to better align LIPA's costs with the revenues it recovers. Also, seasonally differentiated rates put a cash burden on our customers. Many residential customers find it difficult to pay their higher summer utility bills and use balanced billing to mitigate the problem. The elimination of seasonal rates would also benefit commercial customers by leveling out of their electric bills so that they can better manage their cash flows. In short, increasing summer bills hurts customer satisfaction and more importantly is not needed to recover LIPA's costs to serve its customers.

Q. Do other IOUs in New York State have seasonally differentiated rates?

A. Some do, but most do not. Central Hudson, Niagara Mohawk, NYSEG, and Rochester Gas and Electric do not have seasonal rates. Only Consolidated Edison and Orange and Rockland have seasonal rates. PSEG LI's proposal to eliminate seasonal rates is consistent with the majority of other IOUs' delivery rate designs, which have generally been approved as part of joint proposals supported by DPS Staff.

Q. Are there any costs recovered in LIPA's base delivery rates that would be appropriately recovered on a seasonally differentiated basis?

A. Yes. I believe it would be reasonable for LIPA to recover the Power Supply costs reflected in LIPA's base delivery rates on a seasonally differentiated basis.

Q. What power supply costs are reflected in LIPA's base delivery rates?

A. The proposed base delivery rates reflect power supply costs of $505.6 million in 2016. The power supply costs are projected to be incurred (i) under the Power Supply Agreement ("PSA") between National Grid Generation LLC and LIPA, and (ii) as operation and maintenance ("O&M") expenses associated with LIPA's investment in the Nine Mile 2 point nuclear facility.

Q. Do the power supply costs reflected in LIPA's base delivery rates have a seasonal aspect?

A. Yes. Power supply costs incurred through the PSA and for Nine Mile 2 O&M have a seasonal aspect.

Q. Why do PSA and Nine Mile O&M costs have a seasonal aspect?

A. To minimize the cost of meeting the expected system load duration curve, LIPA has various types of productions plants. To determine the optimal system resource mix, both capital and energy costs must be taken into account. Baseload plants typically have higher capital costs and lower energy costs because that produces the lowest total cost for meeting baseload or year-round production requirements. Peaking plants have the lowest capital cost, but the highest energy costs. Because baseload plants operate for many hours of the year, it is reasonable to develop an allocation methodology that recognizes that it is average demand that contributes to the portion of load best served by baseload plants. In contrast, it is the peak load that contributes to the selection of peaking. Further, in between the peaking capacity and baseload capacity there are intermediate units that are more economic to run for more hours than a peaking unit, but fewer hours than a baseload unit. In this case, the system peak is reasonably measured as the average of the 12 monthly coincident peaks (12CP). Using 12CP recognizes that the total load, including customer demand, demand on capacity for scheduled maintenance, forced outages, and unit deratings, is a cost causative factor for LIPA's power supply costs. The need to recognize the cost causative aspects of system planning and design makes the use of the 12CP allocation methodology the appropriate cost allocation method for production plant, because production costs are not tracked by these power plant types.

The 12CP allocation methodology is widely accepted as an appropriate approach for aligning cost causation and cost responsibility in power systems where the cost of energy is a major consideration in generation system planning. For example, utility systems dominated by high cost thermal generation can invest very substantial amounts to add generation capacity that reduces energy costs. The energy cost savings from higher thermal efficiencies more than justify the additional investment per kilowatt of capacity. Systems with high energy (i.e., fuel) costs and high system load factors realize the greater benefits from investing more capital to reduce energy costs. They have more kilowatt hours ("kWh") of consumption to offset the additional capital costs, and their costs for peaking capacity are relatively modest. The economic logic for investing more heavily in thermally efficient baseload and cycling capacity is compelling.

Q. Why is it appropriate to use seasonally differentiated rates to recover power supply costs but not to recover T&D delivery costs?

A. As I have explained, the T&D system is sized for the maximum system or customer load, which is measured over a 15-minute interval. The different loads placed on the T&D system during various seasons will not change the factors that cause these costs to be incurred. In contrast, aligning the recovery of power supply costs in a seasonal manner properly aligns cost recovery with the factors that cause the costs to be incurred.

Q. Have you calculated seasonally differentiated delivery rates based on the PSA and Nine Mile O&M costs?

A. Yes, as identified above, the PSA and Nine Mile O&M costs total $505.6 million ("Production Cost in Delivery"). Using the ECOSS (12CP) allocation factor, I allocated 43% of the Production Cost in Delivery to the four summer months and

57% of the Production Cost in Delivery to the eight winter months. Using the sales by class for residential, small commercial and large commercial service classes, I was able to calculate a per kWh energy seasonal rate differential. For the residential service class the differential per kWh rate is $0.0009 and for small commercial and large commercial service classes the differential per kWh rates are $0.0072 and $0.0047, respectively. The detailed calculations of these rates are presented in Exhibit___ (JTT-11), schedule 10. The resulting rates are also identified in Exhibit___ (JTT-11), schedules 3A, 3B, and 3C for the residential non-TOU rates and for both small commercial and large commercial rates.

D. Large Demand Commercial Customers

Q. What is the Rates Panel's proposal for Large Demand Commercial Customers?

A. The Rates Panel proposes to increase the Large Commercial Customer Charges by applying an 11% increase each year to both the customer charge and the demand charges.

Q. Do you agree with the Rates Panel's proposal for Large Demand Commercial Customers?

A. I generally accept the Rates Panel's proposal. As identified in my direct testimony, the current demand rates collect approximately 40% of the revenue requirement for the Large Demand Commercial Customers and PSEG LI was targeting a redesign where the demand charges would collect 50% of the revenue requirements. The Rates Panel proposal increases the demand rates by 11% per year for the three years, which equates to demand rates that would collect 51.7% of the revenue requirement.

Assuming that seasonality is removed from the delivery rate design as described above, the Rates Panel's proposal will provide the fixed cost recovery requested.

E. Critical Peak Pricing Rate Schedule

Q. The Rates Panel proposes that LIPA should implement a voluntary Critical Peak Pricing rate schedule; do you agree?

A. I generally agree that LIPA should create a Critical Peak Pricing rate schedule, but the timing of this rate plan proceeding does not afford enough time to implement it. A Critical Peak Pricing rate schedule would require studies on how to design and implement it. These studies take time and the information technology ("IT") system changes required to implement such a rate schedule would also take time to implement. Critical Peak Pricing should also be designed in consideration with PSEG LI's plan to implement the Advanced Meter Initiative ("AMI"), but as of today PSEG LI does not have authorization to implement AMI. In addition, the Rev Track 2 proceeding may completely change the way a Critical Peak Pricing tariff will be implemented. Therefore, the implementation of Critical Peak Pricing should be implemented at a later time with the input from Rev Track 2 and in conformity with LIPA's AMI meter implementation.

F. Standby Rates

Q. What is the Rates Panel's position on the proposed Standby Service rates?

A. The Rates Panel disagrees with PSEG LI's proposal to establish a new Standby Service to replace Back-up and Maintenance Service, and recommends that PSEG LI monitor the Commission's REV Track Two proceeding for future guidance in setting these rates.

Q. Do you agree with the DPS Rate Panel's position on the new Standby Service rates?

A. PSEG LI's proposal was designed to conform to the rate design of the other Standby Service tariffs in the State. If the DPS wants LIPA to wait for the new version of Standby rates to come out in Rev Track 2, PSEG LI has no objection.

G. <u>Delivery Service Adjustment</u>

Q. What is the DSA Panel's position concerning the DSA?

A. The DSA Panel recommends that the DSA proposed by LIPA and PSEG LI should be implemented with one significant exception. The exception is that it would impose a limit on the Storm Reserve.

Q. What is the DSA Panel's position on the Storm Reserve in the DSA?

A. The recommendation is that the storm reserve be capped at no more than 1.5 times the expense amount included in base delivery rates each year and that amounts collected above the cap be used to offset charges in other DSA cost components or to pay down debt if the balance grows beyond acceptable levels.

Q. Do you agree with the DSA Panel's recommendation?

A. I do not object to imposing a limit on the size of the storm reserve and I do not object to using the amount received above the storm reserve cap to pay down debt. This would provide clarity and transparency to the storm tracking proposal. In Mr. Falcone's testimony he recommends that the storm reserve limit should be set to $75 million. Basing the storm reserve limit on a factor tied to a budget as proposed by the DSA Panel is arbitrary. Therefore, PSEG LI proposes to change the DSA tariff to reflect the storm reserve limit of $75 million.

Q. Are there any aspects of the proposal to recover storm costs through the DSA that require further clarification?

A. Yes. In our initial filing, the storm costs eligible for recovery through the DSA were defined as "Major Storm Costs" by reference to the definitions of "Major Storms" that is set forth in the Commission's regulations. This was not correct. As the DPS Staff has recognized in this proceeding the definition of a "Storm Event" under the Amended and Restated Operations Services Agreement between PSEG LI and LIPA (the "OSA") differs from the Commission's definition of a "Major Storm." Specifically, a "Storm Event" is defined in the OSA as an event where at least 15,400 customers are interrupted or at least 150 outage jobs are logged, in each case within a 24-hour period due to the storm. The DSA was intended to provide a reconciliation between the costs included for the Storm Event Reserve in LIPA's base delivery rates and the actual costs incurred during the DSA Tracking Periods. Accordingly, the language of the DSA provision of LIPA's tariff needs to be conformed to the OSA definition of Storm Event costs. Exhibit ___ (JTT-12) contains revised tariff leaves concerning the DSA that include the appropriate definition of Storm Event costs.

H. Low Income Discounts

Q. What is the Customer Service Panel's position on PSEG LI's proposed low income discounts?

A. The Customer Service Panel agrees with PSEG LI's proposal to increase the residential heating low income discount to the full customer charge in 2016. However, since the Rates Panel did not accept the increase in the residential customer charge the Customer Service Panel recommends rejecting the proposed increase to the residential non-heating low income discount.

Q. Do you agree with the Customer Service Panel position on the low income discounts?

A. In theory, yes. The low income discount needs to be tied to the residential customer charge. However, PSEG LI strongly recommends that the residential customer charge and the low income discount for non-heating customers be increased as originally proposed.

I. Removal Charge

Q. What is the Customer Service Panel's position on the Removal Charge?

A. The Customer Service Panel recommends that the proposed Removal Charge should be rejected, since "LIPA's tariff already includes investigation fees when theft of service is found" (page 23, line 16).

Q. Do you agree with the DPS Customer Service Panel's position on the Removal Charge?

A. As long as LIPA is permitted to modify its tariff to clearly provide that it will be permitted to recover the cost of turn-offs as part of its investigation fees, I do not object to this recommendation.

Q. Have you included proposed tariff language that would accomplish this result?

A. Yes. That language is included in Exhibit ___ (JTT-12) on tariff leaves 154 and 155.

J. Proposed Rates

Q. Are you presenting the overall results of your recommendations on Delivery Rates?

A. Yes. In Exhibit___ (JTT-11) revised rate design and bill impact statements have been prepared to account for my recommendations as stated above and also to account for the changes to revenues addressed in the PSEG LI Revenue Requirements Panel. I am also a member of that Panel.

Q. Are you presenting modified Tariff leaves based on your recommendations concerning Delivery Rates?

A. Yes. Exhibit___ (JTT-12) contains revised tariff leaves that reflect my recommendations as well as recommendations advanced by DPS Staff that PSEG LI agrees with, and also account for the changes to revenues addressed by the PSEG LI Revenue Requirements Panel. Also, I have identified some typographical errors and other minor changes to the tariffs, which are set forth in Exhibit__ (JTT-12). This Exhibit sets forth all tariff changes that have been identified in discovery in this proceeding. A list of the proposed tariff changes and the justification for them is set forth in Exhibit ___ (JTT-13).

K. Net Metering Issues

Q. Please describe your understanding of the issues raised by the Commission's December 15, 2014 Order in Cases 14-E-0151 and 14-E-0422.

A. In the December 15 Order in Cases 14-E-0151 and 14-E-0422, the Commission directed the State's IOUs to increase the net metering cap from 3% to 6% of electric peak demand. The Commission also directed the IOUs to file tariffs that substitute volumetric crediting for monetary crediting at non-demand remote net metered locations.

Q. Should LIPA increase its net metering cap from 3% to 6%?

A. No. LIPA is well below the 3% cap at this time. Moreover, it is quite possible that improvements to the net metering program will be adopted in the REV Track 2 proceeding. Under these circumstances, LIPA should leave the cap at 3%.

Q. Is it necessary for LIPA to modify its tariff to substitute volumetric credits for monetary credits at non-demand remote net metered locations?

A. No. LIPA's tariff essentially requires all remote net metered locations to be demand metered, because the size of their load, which is used to determine their rate class, takes into account the amount of solar generation at the site. So there is no need for a change.

Q. Should LIPA make any changes to its tariff to comply with Section 66-j of the PSL?

A. Yes. LIPA should update the capacity limitations for net metered generation equipment such as fuel cells in its compliance filing in this proceeding.

IV. <u>CONCLUSION AND SUMMARY</u>

Q. Please summarize the findings and recommendations of your rebuttal testimony.

A. I have reached the following findings and recommendations:

1. Residential and Small Commercial Customer charges should be increased based on the cost justifications provided in my direct testimony.
2. The grandfathered residential water heating rate should be phased out over the three-year rate plan.
3. The Rates Panel's recommendation to phase-out residential electric space heating rates should be rejected.
4. The residential inclining block rate should be eliminated.
5. For the non-heat service classes, the seasonal differential in energy and demand rates should be eliminated.
6. The winter demand ratchet for large commercial customers should be set to 85% to match the summer demand ratchet.
7. For Rate Code 281, the Rates Panel's recommendation to increase the customer charge and demand charge by 11% is acceptable to PSEG LI as long as the seasonal differential is eliminated.

8. The Rates Panel's proposed voluntary Critical Peak Pricing rate schedule should be considered as part of the REV Track 2 proceeding along with AMI implementation.
9. It is acceptable to delay implementation of a new Standby Service until the REV Track 2 proceeding is completed.
10. The low income discount for non-heat customers should be increased as originally proposed by PSEG LI along with the proposed customer charge.
11. The Removal Charge can be addressed through a tariff modification that would permit LIPA to recover the cost of turn-offs along with investigation and inspection fees charged.

Q. Do you have any closing comments?

A. Yes. I would like to identify an overarching theme in my rebuttal testimony. PSEG LI is in a unique position; as compared to IOUs operating in New York, PSEG LI has no profit motive to increase sales or increase rate base. PSEG LI does have a profit motive to provide reliable and dependable service. The metrics established in the OSA focus PSEG LI's motivation on customer satisfaction. This motivation is a prime basis of my rate design proposals. I am proposing rate design changes that will increase fairness (i.e., the customer charges), reduce high summer bills (i.e., removing seasonality in rates) and help our commercial customers to better manage cash flow (i.e., removing seasonality, changing the winter demand ratchet). I am also disputing the Rates Panel's proposals that would negatively affect customer satisfaction (i.e., elimination of the electric space heating rate). These rate design changes should have a positive effect on LIPA's customers' satisfaction. Conversely, if these rate design changes are rejected, such rejection may limit PSEG LI ability to achieve the levels of customer satisfaction identified in the OSA.

Q. Does this conclude your rebuttal testimony?

A. Yes.

JUDGE PHILLIPS: The next panel?

MR. WEISSMAN: We have affidavits for two more pieces of testimony this morning, Your Honor, or this afternoon I should say. The next one is for the Power Supply Panel. This is the affidavit of Paul Napoli and James Wittine who submitted direct testimony on January 30, 2015 under the heading of Power Supply Panel. That was a 20 page document including four exhibits. Those four exhibits, each of which are a single page, are identified as Exhibits 41 through 44 on Your Honors' exhibit list. Again, all of this material was submitted on January 30, 2015, and I offer to you the affidavit of Mr. Napoli and Mr. Wittine (handing).

JUDGE PHILLIPS: The affidavit of the Power Supply Panel has been marked for identification as Exhibit 124. On the basis of these affidavits, we ask that the testimony of the Power Supply Panel consisting of 20 pages be copied into the record as though given orally today.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-____________

DIRECT PRE-FILED TESTIMONY
OF
THE POWER SUPPLY PANEL

Date: January 30, 2015

WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Power Supply Panel (the "Panel").
A. We are Paul Napoli and James Wittine.

Q. Mr. Napoli, please state your full name and business address.
A. Paul Napoli. My business address is 333 Earle Ovington Blvd, Uniondale, NY 11553.

Q. By whom are you employed and in what capacity?
A. I am Vice President of Power Markets for PSEG Long Island LLC ("PSEG LI"). In that capacity, I have responsibility for overseeing the electric supply planning and contracting that PSEG LI performs for the Long Island Power Authority ("LIPA") under the Amended and Restated Operation Services Agreement ("OSA") between those parties.

Q. Please describe your educational and professional background.
A. I received a Bachelor of Engineering from Stevens Institute of Technology with a Major in Civil Engineering in 1979. In 1985, I received an MBA in Finance from Seton Hall University, and in 1998, I received a certificate in Mergers and Acquisition from UCLA. I have more than 35 years of experience in utility operations and strategy in both Gas and Electric Transmission operations for Public Service Electric and Gas Company ("PSE&G") and its affiliates. Most recently, I served as PSE&G's Director of Transmission Business Strategy and Services. I have also served as Chairperson of the PJM Transmission Owners Administrative Committee.

Q. Have you previously testified before any regulatory authority?

A. Yes. In PJM Interconnection LLC, FERC Docket No. ER06-456-006, I testified on behalf of the PJM Transmission Owners in support of certain tariff modifications to PJM's Open Access Transmission Tariff.

Q. Mr. Wittine, please state your full name and business address.

A. James Wittine. My business address is 333 Earle Ovington Blvd, Uniondale, NY 11553.

Q. By whom are you employed and in what capacity?

A. I am Manager of Planning and Analysis for PSEG LI. In that capacity I have responsibility for a number of activities including the development of budgeted fuel and purchased power costs and the estimated annual capacity charge under LIPA's Amended & Restated Power Supply Agreement ("PSA") with National Grid Generation, LLC ("NGG").

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Electrical Engineering from Lowell Technological Institute in 1968. In 1998, I received an MBA from the University of Delaware. I have more than 40 years of experience in utility operations, strategy, contract negotiations and regulation having been employed by: the Virginia State Corporation Commission ("VSCC") (1974 – 1982); Delmarva Power & Light Company ("DP&L") (1983 – 1998); Navigant Consulting Inc. (1999 – 2005); and LIPA (2006 – 2014).

Q. Have you previously testified before this or any other regulatory authority?

A. Yes. As General Director of Public Utilities at the VSCC I testified in numerous proceedings on behalf of the VSCC Staff on such matters as: cost allocation; rate design; revenue requirements; fuel and purchased power clauses; power plant performance; and incentive rate making. As General Manager of Regulatory Practice at DP&L I sponsored testimony before the Public Service Commissions of Delaware and Maryland, the VSCC, and the Federal Energy Regulatory Commission ("FERC").

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support the power supply-related proposals and costs set forth in the three-year Rate Plan that covers calendar year ("CY") 2016 through CY 2018. Specifically, we will;

(i) provide an overview of the power supply-related proposals and costs reflected in the three-year Rate Plan and describe the power supply-related assumptions that have been made in preparing that plan,

(ii) describe how LIPA currently meets the power supply requirements of the customers it serves,

(iii) describe the role that PSEG LI and its affiliates perform under the OSA in planning for and providing the power supply requirements of LIPA and its customers,

(iv) discuss the power supply costs that are currently projected to be incurred in the 2016-2018 rate period and the method by which those costs will be reflected in LIPA's rates,

(v) describe the process that is being followed to plan for LIPA's power supply requirements during the 2016-2018 period and beyond,

(vi) discuss how that process may lead to decisions that will affect the rates charged by LIPA during the 2016-2018 period, and

(vii) discuss our proposal to establish a new proceeding in which interested parties will collaborate to determine if it is feasible to implement a competitive power supply market on Long Island, and if so, to determine what steps are required to implement such a market and encourage retail choice.

Q. Do you sponsor any exhibits as part of your direct testimony?

A. Yes. We sponsor the following exhibits which were prepared under our direction and supervision:

(i) Exhibit __ (PSP-1) sets forth the budget for PSEG LI's Power Markets organization for CY 2015 through CY 2018;

(ii) Exhibit__ (PSP-2) provides information concerning the generation and transmission resources that are currently under contract to LIPA or owned by LIPA to serve its electric supply requirements;

(iii) Exhibit__ (PSP-3) sets forth a breakdown of the non-fuel power supply-related costs that are projected to be incurred and consequently recovered in LIPA's base delivery rates[1] for the years 2015-2018 based on the current baseline assumptions that underlie the Three Year Rate Plan; and

(iv) Exhibit __ (PSP-4) sets forth a breakdown of the power supply-related costs[2] that are projected to be incurred and consequently recovered through LIPA's

[1] These costs are associated with the PSA and LIPA's 18% ownership interest in the Nine Mile Point 2 ("NMP2") nuclear generation facility.

[2] These costs include such items as the cost of gas and oil used in electric generation and purchased power.

monthly Fuel and Purchased Power Cost Adjustment rate ("FPPCA"), more commonly known as the Power Supply Charge.

Q. Please provide an overview of PSEG LI's power-supply related recommendations in this proceeding.

A. In preparing the three-year Rate Plan, PSEG LI has developed a baseline power supply plan that is designed to ensure that LIPA has access to power supplies that meet the planning and reliability standards established by the National Electric Reliability Council ("NERC"),[3] the New York State Reliability Council ("NYSRC"), and the New York Independent System Operator ("NYISO"), while also preserving all of LIPA's existing options to develop new electric generation or transmission projects that are currently under evaluation. This plan generally assumes that all generation and transmission facilities currently included in LIPA's resource base remain available to meet LIPA's power supply requirements. At the same time, except as we describe more fully below with respect to certain projects, this plan does not reflect the addition of significant new power supply resources during the 2016-2018 period. Currently, we are undertaking a process that will enable us to make more definite assumptions about LIPA's future power supply requirements by December 2015. To the extent that this process results in changes – up or down – in power supply costs during the 2016-2018 period, those changes will be reflected in

[3] NERC is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by FERC and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people.

LIPA's rates through changes in the FPPCA or in other proposed cost tracking mechanisms that are discussed in the testimony of PSEG LI witness Joseph Trainor.

Q. Please describe PSEG LI's role in managing LIPA's power supply and the steps that PSEG LI has undertaken to fulfill that role.

A. Pursuant to the OSA, PSEG LI assumed contractual responsibility for a number of LIPA's essential functions on January 1, 2014. The responsibility for planning for LIPA's power supply needs was fully transitioned to PSEG LI on January 1, 2015. PSEG LI engaged in a comprehensive review of the resource planning methodologies used in assessing LIPA's needs for power supply resources. After a careful review of the methodologies used historically by LIPA, PSEG LI recommended that LIPA recognize the planning criteria established by the NYSRC and the NYISO, and utilized by all of New York's investor owned electric utilities. Based on the application of these planning criteria, PSEG LI also recommended that LIPA defer committing to additional power resources until PSEG LI completes an Integrated Resource Plan ("IRP"). This latter recommendation did not apply to the incremental renewable projects that are discussed later in our testimony. Refraining from adding additional power supply sources will enable LIPA to avoid significant additional power supply costs in the 2016 – 2018 period. However, it is now necessary for PSEG LI to conduct a comprehensive review of LIPA's resources through the IRP process.

Q. How does PSEG LI administer the management of LIPA's power supply?

A. PSEG LI administers LIPA's power supply through its Power Markets organization. This organization comprises three major areas: Strategy and Planning; Cost and Rate

Impact Analysis; and Power Resources Contract Negotiation and Management. Personnel within the Power Markets organization perform long-term supply planning including the development of the IRP process that we describe more fully below. The Power Markets organization also manages power plant contracts, transmission service agreements, and LIPA's minority ownership interest in the Nine Mile Point II ("NMP2") nuclear facility. In addition, Power Markets supports LIPA's management of its NYISO, PJM, ISO-New England and FERC relationships and develops and monitors LIPA's fuel and purchased power budget. The Power Markets organization was created in 2015 by combining the functions of LIPA's Power Supply Department with staff from PSEG LI with expertise in the areas of resources planning, power asset management and power contract oversight. The organization consists of 21 employees.

Q. What is the budget for the Power Markets organization for CY 2015 – CY 2018?

A. The budget for the Power Markets organization for CY 2015 – CY 2018 is set forth in Exhibit __ (PSP-1). The major budget items are labor and benefit costs and external costs associated with resource planning, procurements and project management. In addition, relatively modest costs are budgeted for transmission studies, association and professional dues and fees, data systems, and administrative and general expenses.

Q. What is involved in the comprehensive review of LIPA's Energy Resources Plan based on the revised planning criteria?

A. The first step is a detailed assessment of the condition of LIPA's existing electric capacity resources and a technology assessment of the future of energy supply. In addition, a full IRP must be developed that estimates LIPA's future resource needs.

Q. What will happen when these activities are completed?

A. Once these activities are completed, Power Markets will be in a better position to evaluate LIPA's options for addressing those needs. This will include evaluation of various options such as new "On-Island" capacity, the repowering of existing capacity, possible transmission solutions, election of unforced delivery rights[4] on existing transmission lines, and energy efficiency/demand response activities. Once those options have been fully considered and evaluated, we will have a more accurate assessment of LIPA's potential portfolio of future resources, including the impact of various power supply options on LIPA's rates and the achievement of other goals and objectives such as emission reductions.

Q. How do you determine future resource needs?

A. LIPA has a total minimum obligation and a minimum On-Island capacity obligation. The minimum On-Island obligation is that portion of the forecasted peak that must be satisfied with capacity physically located on Long Island or otherwise recognized as On-Island capacity by the NYISO.

[4] Unforced delivery rights represent the possible procurement of firm generating unit capacity in neighboring regional transmission organization, such as PJM or ISO-New England.

LIPA's total minimum capacity obligation in megawatts (MWs) is determined by the following formula:

Total Minimum Capacity Obligation = LIPA Projected Coincident[5] Peak Load + (LIPA Projected Coincident Peak Load x IRM[6])

LIPA's minimum On-Island capacity obligation (MWs) is determined by the following formula:

Minimum On-Island Capacity Obligation = LIPA Zone K Projected Peak Load x LCR[7]

LIPA's additional or incremental capacity need equals:

Total Minimum Capacity Obligation – (Contracted Resources + Market Capacity Purchases)

LIPA's minimum On-Island additional or incremental capacity need equals:

Minimum On-Island Capacity Obligation – (On-Island Contracted Resources + On-Island Market Capacity Purchases)

Q. What does the term "Locational Capacity Requirement" ("LCR") mean?

A. LCR is one of the two primary planning criteria established by the NYISO that LIPA is required to meet and refers to the amount of capacity required to be located On-Island or otherwise recognized as "On-Island" by the NYISO. The other criterion is known as the Installed Reserve Margin ("IRM").

[5] Coincident with the New York Control Area peak load.

[6] IRM stands for Installed Reserve Margin. The IRM is established annually by the NYS Reliability Council.

[7] LCR stands for Locational Capacity Requirement. The LCR is established annually by the NYISO.

Q. What is the significance of the criteria established by the NYISO?

A. The NYISO manages the network of high voltage lines that form New York State's electric transmission grid and facilitates the dispatch and operation of electric generating units along with the administration of the wholesale power market in New York. As a member Transmission Owner of the NYISO, LIPA must adhere to the NYISO rules and criteria that prescribe the technical and reliability conditions under which the New York state transmission system must be designed and operated.

LIPA's transmission system is located in NYISO Zone K which comprises Suffolk and Nassau Counties and the Far Rockaway peninsula. The LCR is the specified percentage of electric load in Zone K that must be served by resources that qualify as On-Island resources; that is, resources physically or otherwise deemed by the NYISO to be physically located in Zone K. Due to transmission constraints, Zone K historically has been considered a "load pocket" requiring a high percentage of peak demand to be met with On-Island resources. LIPA's LCR for the planning year ending April 30, 2015 is 107%, meaning that LIPA and other responsible entities in Zone K must have On-Island resources at least equivalent to 107% of the NYISO-determined peak demand for Long Island.

Q. Who are the other responsible entities in Zone K?

A. The other responsible entities in Zone K are the Villages of Freeport, Greenport and Rockville Centre, the New York Power Authority and the participating load serving entities ("LSEs") in LIPA's retail access program (Long Island Choice). The peak demand served by LIPA is approximately 95% of the total peak demand in Zone K.

Q. What does the term Installed Reserve Margin ("IRM") mean?

A. Under the NYISO's rules there must be enough electric capacity statewide to meet the combined projected peak demand of all LSEs, plus the IRM. The IRM is a statewide requirement that is established annually by the NYSRC and is currently 17% for the planning year ending April 30, 2015. The IRM requirement is allocated to each LSE based on demand that is coincident to the total NYISO peak demand.

Q. How is the IRM determined?

A. The IRM is evaluated by applying principles of probability "such that the loss of load expectation ("LOLE") of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year," or one day in ten years. This calculation incorporates guidelines and procedures of the Northeast Power Coordinating Council[8] and the reliability standards of NERC. The 0.1 day per year standard is an industry standard used by other regional transmission organizations such as PJM and ISO New England.

[8] Northeast Power Coordinating Council, Inc. ("NPCC") is a not-for-profit corporation responsible for promoting and improving the reliability of the international, interconnected bulk power system in Northeastern North America. NPCC carries out its mission through (i) the development of regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards, coordination of system planning, design and operations, and assessment of reliability (collectively, "regional entity activities"), and (ii) the establishment of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria (collectively, "criteria services activities"). NPCC provides the functions and services for Northeastern North America of a cross-border regional entity through its regional entity division, as well as regionally-specific criteria services for Northeastern North America through its criteria services division.

The NPCC geographic region includes the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. Overall, NPCC covers an area of nearly 1.2 million square miles, populated by more than 55 million people.

Q. How does LIPA presently provide the power supply requirements of its customers?

A. LIPA purchases its power supply from a variety of generation providers. LIPA also owns a tenant-in-common interest in the NMP2 nuclear facility. Exhibit__ (PSP-2) sets forth the power supply resources under contract to LIPA. Almost all of LIPA's power supply is under long term power purchase agreements ("PPAs") with expiration dates ranging from 2015 to 2034. The majority of LIPA's power supply is provided under the following long-term contracts:

1. Power Supply Agreement ("PSA") – This tolling Agreement, which is on file with, and subject to cost of service regulation by, FERC provides for the sale to LIPA by NGG of all of the capacity of the oil and gas-fueled generating plants that were formerly owned by the Long Island Lighting Company ("LILCO") prior to the acquisition of LILCO and its transmission and distribution assets by LIPA in 1998. The PSA provides about 60 percent of LIPA's capacity and 26 percent of its annual energy requirements.

2. Caithness Energy Center – LIPA has a long term contract with the owner of this gas fired combined cycle plant that is located on Long Island. Under this tolling agreement LIPA procures approximately 286 MWs of capacity. Caithness has produced about 10 percent of LIPA's annual energy requirements since 2009.

3. Neptune Regional Transmission System – LIPA has a long term Firm Transmission Capacity Purchase Agreement ("FTCPA") for this 660 MW High Voltage, Direct Current ("HVDC") submarine cable. The FTCPA enables LIPA to procure about ten percent of its On-Island capacity and about 20 percent of its annual energy requirements from the PJM market. The On-Island capacity is from a long-term capacity purchase agreement LIPA has with the Marcus Hook facility (685 MW).

4. The Cross Sound Cable – This is a 330 MW HVDC submarine cable to New England that enables LIPA to procure On-Island capacity and energy from ISO New England. Currently LIPA procures approximately 100 MW of capacity qualified as On-Island capacity from Bear Swamp.

Q. Do LIPA's power supply resources include renewable resources?

A. Yes. LIPA currently purchases solar energy from a number of solar projects on Long Island as well as hydroelectric power from Brookfield. The baseline plan that we have described for 2016-2018 also includes plans for two additional, fully subscribed solar feed-in tariffs that are projected to provide approximately 150 MW of solar-powered electricity as well as an additional feed-in tariff for up to 20 MW of non-solar renewable power. The costs of these projects are included in the projection of fuel and purchased power costs presented in Exhibit __ (PSP-4).

In addition, on December 17, 2014 LIPA's Trustees authorized conducting negotiations[9] of individual 20-year PPAs for 11 different solar proposals which in aggregate constitute 122 MW. In addition, the Trustees authorized commencement of a supplemental solicitation to secure renewable energy of up to an additional 160 MW of renewable capacity commencing delivery on or before December 31, 2020. Furthermore, the Trustees authorized PSEG LI working with LIPA staff and other stakeholders to develop an additional program, integrated with the IRP, for additional renewable energy beyond the 280 MW target of those two sets of additional renewable projects. Because no contracts have been fully negotiated, executed or approved none of the costs associated with the 280 MW target projects or additional

[9] Any potential PPA is subject to further authorization by the Trustees.

renewable projects beyond the 280 MW target are included in the projection of fuel and purchased power costs presented in Exhibit ___ (PSP-4).

Q. What does the term "feed-in tariff" mean?

A. The term "feed-in tariff" describes an offer by the utility – LIPA in this case – to purchase a specific type of renewable generation from willing suppliers at a fixed energy price per kilowatt-hour for a specific period of time. The offer price is stated in the tariff and is available to every supplier that meets the criteria, up to the maximum level of capacity specified. The supplier under such a tariff receives a fixed price for its energy output for twenty years under a standard form PPA.

Q. In planning for its power supply requirements does LIPA account for the impacts of its energy efficiency programs?

A. Yes. The effect of energy efficiency is reflected in the projected load and energy forecast such that the peak load and energy forecast is lower than it otherwise would be in the absence of the energy efficiency programs. The full impact of Special Case Resources ("SCRs") is also reflected in the forecast. These resources will reduce the level of LIPA's electric supply requirements.

Q. What are SCRs?

A. SCRs are demand side resources that are available in energy shortage situations to maintain the reliability of the power grid. Commercial and industrial customers sign up for the SCR program in which they are paid by the NYISO to reduce energy consumption when they are asked to do so. SCR participants are required to reduce power usage when they are notified to do so.

Q. Is it expected that LIPA will continue to have access during the 2016 – 2018 period to the same resources that it currently relies upon for its power supply requirements?

A. Yes. As discussed more fully below, during the 2016-2018 period certain PPAs that LIPA has with suppliers will expire. It is currently our expectation that these facilities will continue to participate in the NYISO capacity and energy markets as On-Island resources.

In addition, in 2015, we expect that a 530 MW generating facility located in Danskammer, New York will be reactivated. This is expected to reduce LIPA's Zone K LCR by about three percent. Assuming this is the case, LIPA's actual On-Island capacity supply margins are expected to remain well in excess of the applicable LCR obligation through the period covered by the Rate Plan and for several years beyond.

Q. Is there any risk that LIPA's customers will face a shortfall of electricity supply if the planning forecast proves inaccurate or LIPA loses access to one of its current resources?

A. The probability of a shortfall is low. Moreover, there are a number of ways to effectively manage an unforeseen need for additional power supply. For example, LIPA can bring certain emergency generation resources on-line at Shoreham and Holtsville. This option has been used by LIPA before. In addition, LIPA can undertake measures such as (i) curtailing company use, (ii) reducing voltage, and (iii) obtaining emergency support from the NYISO and neighboring ISOs.

Q. Will LIPA's power supply needs be examined in the IRP that you discussed earlier?

A. Yes. The IRP will examine LIPA's resource needs and the uncertainties that may affect them. As we stated previously, during 2015 we will conduct a process to complete the IRP. This process will include solicitation and incorporation of public input. Once those activities are completed, we will review the existing responses to various requests for proposals ("RFPs") that have been issued by LIPA in the past few years and consider the various power supply options available to LIPA, including new generation and transmission solutions. We will also evaluate the impact of Utility 2.0 and the availability of capacity purchases using the Cross-Sound Cable.

Q. What is Utility 2.0?

A. Utility 2.0 is a proposal by PSEG LI to implement energy efficiency measures, distributed generation and advanced electric grid technologies designed to provide customers with the means to more effectively and efficiently manage their electric usage. The proposed program would also expand certain solar and geothermal programs. The Utility 2.0 program, which is under further review by the New York State Department of Public Service, is described in greater detail in the testimony of the Utility 2.0 Panel.

Q. How does LIPA recover the costs of power supply from its customers?

A. LIPA recovers a portion of its power supply costs through its base delivery rates and the remainder through its monthly FPPCA. Specifically, LIPA recovers the non-fuel related costs incurred under the PSA and the non-fuel related costs associated with its investment in NMP2. These costs historically were recovered in LILCO's base rates prior to its acquisition by LIPA. The remainder of LIPA's power supply costs, except for certain payments-in-lieu-of-taxes associated with some PPAs, are recovered through the monthly FPPCA.

Q. Do LIPA's proposed base delivery rates for 2016-2018 reflect changes in power supply-related costs that are recovered through those rates as compared to the level of such costs in 2014?

A. Yes. The changes in the power supply-related costs recovered in base delivery rates in 2016-2018 are primarily the product of (i) projected increases in the annual Capacity Charge under the PSA, and (ii) LIPA's pro rata share of projected capital investments and operation and maintenance costs associated with NMP2. These costs are set forth on Exhibit __ (PSP-3).

Q. Do you have a forecast of the costs that LIPA will incur under the PSA for the 2016-2018 period?

A. Yes. Exhibit __ (PSP-3), page 1 sets forth the forecast of costs projected to be incurred under the PSA for the 2016-2018 period. These charges consist of fixed and non-fuel variable charges. In projecting the PSA costs reflected on Exhibit __ (PSP-3), we have assumed, consistent with the baseline assumption, that none of the generating units currently providing service under the PSA will be retired and no generation units that are or have been subject to the PSA will be repowered during the 2016-2018 period.

Q. Is it possible that the actual costs incurred by LIPA under the PSA and with respect to NMP2 will vary from the amounts reflected in the forecast set forth on Exhibit __ (PSP-3)?

A. Yes. The actual costs incurred by LIPA may be different than the original forecast amounts. Two of the more significant drivers of such changes with respect to the PSA are property taxes on the generating facilities subject to the PSA and NGG's pension and other post-employment benefits costs. The difficulty in projecting these costs is one of the reasons that PSEG LI witness Joseph Trainor is proposing a new rate mechanism – the Delivery Service Adjustment – that will permit LIPA to recover, *inter alia*, differences between the actual power supply costs incurred by LIPA in any calendar year and the annual amount of such costs reflected in base delivery rates.

Q. What are the projected capital and operation and maintenance expenditures associated with NMP2 that are included in the proposed baseline delivery rates?

A. Exhibit __ (PSP-3), page 1, sets forth a breakdown of these costs which are billed to LIPA by Exelon Corporation, the operator of this facility.

Q. Has PSEG LI prepared a forecast of the costs associated with electricity supply that will be recovered through LIPA's monthly FPPCA during the 2016-2018 period?

A. Yes. For the period 2016-2018, we forecast that LIPA will incur the following power supply costs ($000):

2016	-	$1,681,830
2017	-	$1,701,494
2018	-	$1,714,252

A breakdown of these costs by year is set forth on Exhibit __ (PSP-4). This forecast is based on the load and energy forecast prepared by the Sales and Revenue Forecasting Panel and excludes Utility 2.0 impacts.

Q. What are the major assumptions that underlie the forecast of costs to be recovered through the FPPCA?

A. The forecast assumes that:

(i) there will be no additional retirement or repowering of conventional power plants; and

(ii) LIPA will be subject to an IRM of 17% and an LCR of 104% throughout the period.

Q. Does the forecast of electric supply costs reflect the expiration of any PPAs that are currently in effect?

A. Yes. LIPA has six PPAs in place with electric generation providers that will expire in the 2016 - 2018 time frame. The forecast assumes that the facilities will continue to operate as On-Island resources and that the capacity and energy provided by these facilities will continue to be available to LIPA through the NYISO capacity and energy markets.

Q. Do any affiliates of PSEG LI play a role in managing LIPA's power supply?

A. Yes. Effective January 1, 2015, PSEG Energy Resources & Trade, LLC (ER&T) assumed responsibility for providing both power supply and fuel management services related to LIPA's power supply resources.

Q. In the longer term, what are PSEG LI's goals for managing LIPA's power supply?

A. In the longer term, PSEG LI's goals for managing LIPA's power supply are:

(i) to reduce the monthly fluctuations and volatility in LIPA's monthly FPPCA rate;

(ii) to review LIPA's existing PPAs including their ramp down rights for opportunities to reduce costs; and

(iii) to complete the IRP to determine energy/transmission and demand response needs for Zone K over the next 20 years.[10]

[10] The first ten years of the period will be actionable, meaning that RFPs will be issued, whereas the subsequent ten years will reflect potential future initiatives.

Q. What processes will you undertake to determine if there is a potential to obtain capacity and energy pricing improvements and/or otherwise reduce costs incurred under LIPA's existing PPAs including the PSA?

A. We will conduct a comprehensive review of LIPA's existing PPAs and the PSA to determine if there is a potential to improve their pricing and/or reduce costs. For example, under the PSA there are various "ramp down" rights that permit LIPA to modify the PSA to eliminate certain facilities covered by the agreement. We will analyze those rights to determine whether it makes sense to exercise them.

Q. How does LIPA's current approach to contracting for electric supply affect the development of a competitive generation market?

A. There is essentially no merchant power development activity and, effectively, no competitive wholesale power market in Zone K. This is largely due to the fact that LIPA has sufficient capacity and purchased power under contract. To encourage capacity development, LIPA has had to support new capacity by entering into long term PPAs. This tends to impede the viability of retail choice programs on Long Island. In PSEG LI's view, it is in the best interest of LIPA and the consumers it serves to move to a more competitive generation market on Long Island, reflective of the competitive market that exists in the rest of New York State. We are proposing to establish a new proceeding in which interested parties will undertake a collaborative process to consider if it is feasible to enhance retail choice in LIPA's service territory, and if so, what steps should be taken to do so. This proposal is also discussed in the testimony of Joseph Trainor.

Q. Does this conclude your testimony?

A. Yes, it does.

JUDGE PHILLIPS: The next panel?

MR. WEISSMAN: Finally, Your Honor, again I have two affidavits covering Wages, Salary and Benefits Panel Direct Testimony. The first executed in New York -- executed in New Jersey by Ms. Stephanie Olexson and Mark Pepe. The second affidavit was submitted in New York by Mr. Robert Greenbaum. These affidavits support the direct Wages, Salary and Benefits Panel testimony filed on January 30, 2015. That testimony consists of 18 pages and had no exhibits attached to it. The affidavits of Mr. Pepe and Mr. Greenbaum (handing).

JUDGE PHILLIPS: The affidavit of the Wages, Salary and Benefits Panel for Stephanie Olexson and Mark Pepe have been marked for identification as Exhibit 125. The affidavit of Mr. Robert Greenbaum of that same panel has been marked for identification as Exhibit 126. On the basis of these affidavits, we ask that the testimony of that panel be copies into the record as though given orally. It consists of 18 pages.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-____________

DIRECT PRE-FILED TESTIMONY
OF
WAGES, SALARY AND BENEFITS PANEL

Date: January 30, 2015

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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Wages, Salary and Benefits Panel (the "Panel").

A. We are Robert Greenbaum, Mark D. Pepe, and Stephanie Olexson.

Q. Mr. Greenbaum, please state your employer and business address.

A. I am employed by PSEG Long Island LLC ("PSEG LI" or the "Company") and my business address is 333 Earle Ovington Blvd, Suite 101 Uniondale, NY 11553.

Q. In what capacity are you employed by the Company?

A. I am employed by the Company as Senior Manager, Employee & Labor Relations and HR Business Partners. My responsibilities are to provide direct oversight for the HR Business Partner, Labor Relations and Employee Relations functions for PSEG LI; provide overall leadership for on-site Human Resources ("HR") on Long Island; and participate in the development, implementation, communication, and administration of the Company's employee benefits programs.

Q. Please summarize your educational background and professional experience.

A. I have 33 years of experience in the utility industry, including more than 20 years in Human Resources. The majority of my time has been spent managing the employee and labor relations functions at the Long Island Lighting Company, Marketspan, KeySpan and National Grid. I have served as the chief spokesperson for numerous collective bargaining agreements for the aforementioned combination electric and gas utilities as well as affiliated HVAC subsidiary companies. In addition to having held the position of Compensation Manager at the Long Island Lighting Company, I have also managed the Human Resource Business partners at KeySpan and have been responsible for all employee investigations at National Grid.

I hold a Bachelor's degree in Management from the State University of New York and an MBA from Dowling College. I have served on various panels at the Cornell School of Industrial Relations in Manhattan and have completed a program on negotiation at Harvard Law School.

Q. Do you belong to any professional societies or organizations?

A. Yes. I am a member of the Society of Human Resource Management and am currently the Chairman of the Edison Electric Institute and American Gas Association Labor Relations Committee.

Q. Mr. Pepe, please state your employer and business address.

A. I am employed by PSEG Services Corporation ("PSEG Services"), located at 80 Park Plaza (T-10), Newark NJ 07101.

Q. In what capacity are you employed by the PSEG Services?

A. I am employed as the Director of Compensation and HRIS (Human Resources Information Systems). My responsibilities include developing and administering Public Service Enterprise Group Incorporated's ("PSEG") compensation programs for non-represented employees including Officers, providing strategic direction for implementing systems that best support delivery of HR products and services, and ensuring protection of employee data.

Q. Please summarize your educational background and professional experience.

A. I have 27 years of work experience including experience in accounting and finance, auditing and human resources. My human resources experience includes the last seven years working as an HR professional, specializing in the area of Compensation and HR Systems. I have experience working in industries that include governmental, healthcare and energy services. I have been employed at PSEG Services since November 1995.

I hold a Bachelor of Science degree in Accounting and Master of Business Administration degree with a concentration in Management Information Systems, both from Saint Peter's University in Jersey City, NJ.

Q. Do you belong to any professional societies or organizations?

A. Yes. I am a member of the Society of Human Resource Management and World at Work which is focused on total rewards.

Q. Ms. Olexson, please state your employer and business address.

A. I am employed by PSEG Services located at 80 Park Plaza (T-10), Newark NJ 07101.

Q. In what capacity are you employed by PSEG Services?

A. I am employed as Director of Employee Benefits. My responsibilities are to provide strategy, delivery and communication of all employee benefit programs at Public Service Enterprise Group ("PSEG") and PSEG LI.

Q. Please summarize your educational background and professional experience.

A. I have 22 years of experience working as an HR professional, specializing in the area of Employee Benefits. I have experience working in industries that include manufacturing, communications and healthcare. I have been employed at PSEG Services since January 2013.

I hold a Bachelor of Arts degree in Human Resource Administration from Saint Leo University of Florida.

Q. Do you belong to any professional societies or organizations?

A. Yes. I am a member of the Society of Human Resource Management, actively involved in the National Business Group on Health, and hold a life, health and accident insurance license from the New Jersey Department of Banking and Insurance.

Q. What is the overall purpose of the Panel's testimony in this proceeding?

A. The purpose of this Panel's testimony is to support the calculation of wages, salaries and benefits that underlie the budgets presented in this filing. In that effort, we will briefly explain the employment arrangements that PSEG LI assumed when it took over the operation of the Long Island Power Authority ("LIPA") on January 1, 2014 pursuant to the Amended and Restated Operating Services Agreement dated as of December 31, 2013 ("OSA"). We will describe the compensation and benefits plans for PSEG LI's employees, both union and management, and explain the structure of those wages, salaries and benefits in the 2015 base year and the escalation factors employed to project wages, salaries and benefits through the end of the 2016-2018 Rate Plan period.

Q. Do you distinguish between the terms "benefits" and "compensation"?

A. Yes. In our testimony, the term "benefits" includes retirement programs (that is, the cost of 401K and pension programs), active and retiree health insurance, life insurance, and disability benefits, as well as vacation and sick pay. Compensation includes base salary and wages, plus the variable component of management pay, and the gain-sharing component of pay to represented employees.

Q. How is this Panel's testimony organized?

A. First, we discuss the role that we played in the process of providing the underlying cost information for wages, salaries and benefits in the budgets that underpin this rate filing. Next, we will briefly give the background of how individuals who were previously employed by National Grid Companies USA or its affiliates (collectively, "National Grid") or LIPA came to be employed by PSEG LI. We then describe the terms and conditions of employment of PSEG LI union and non-union employees that govern their compensation and benefits levels in the 2015 base year budgets. In the sections of our testimony addressing union and non-union employment, we will discuss the escalation factors for both union and non-union management, administrative, supervisory and technical ("MAST") employees that are used to develop their compensation and benefits costs in the 2016, 2017 and 2018 Rate Plan years. Finally, we discuss Executive Compensation.

Q. What role did the Human Resources ("HR") Department play in the process under which the various budgets were developed?

A. Staffing levels were developed by Transmission and Distribution ("T&D"), Customer Service and Business Services groups that were aggregated into the PSEG LI or

"Service Provider" budgets. It was the responsibility of the HR Department to provide information on the labor and benefit costs to be applied to the staffing developed by those groups. The costs, with applicable escalation factors, were developed and assembled by the HR Department and made available to the personnel working on the budgets. We helped develop those costs for the 2015 base year budget process by providing escalation factors to use for employee compensation and benefits for 2015 and for the 2016 through 2018 budgets. Some assumptions were used when developing the benefit budget which will be discussed later in this testimony.

II. PSEG LI'S ASSUMPTION OF THE NATIONAL GRID WORKFORCE

Q. When did PSEG LI assume responsibility for running LIPA's electric operations?

A. Under the OSA, PSEG LI and PSEG LI's subsidiary "ServCo" (referred to interchangeably herein as PSEG LI) agreed to provide the day-to-day management and supervision of the operations of the LIPA T&D system and related services and functions, starting January 1, 2014.

Q. Did the OSA affect PSEG LI's staffing of the ServCo operations?

A. Yes, it did. The OSA specifically addresses ServCo's hiring of union and MAST employees, as well as the terms and conditions of that employment.

Q. How does the OSA address the hiring of National Grid's union employees?

A. The OSA required PSEG LI to offer employment to National Grid's union employees in order to provide the same level of services that National Grid had been providing to LIPA. The OSA also required PSEG LI to follow the collective bargaining agreements (“CBAs”) that were in effect with IBEW Local 1049 and required PSEG LI to abide by the terms and conditions of the CBA until its expiration. In February 2014, PSEG LI reached an agreement with the union that extended the contract that would have expired February 13, 2015 through November 12, 2016.

Q. What about National Grid’s former MAST employees?

A. Under the OSA, ServCo was also required to offer employment to National Grid’s non-union employees “as necessary for ServCo to provide Operations Services under” the OSA.

Q. Were the hiring prescriptions in the OSA limited to the hiring of National Grid employees?

A. No. The OSA also stated that PSEG LI could hire additional employees necessary to supplement the transitioned National Grid employees. The number of employees fitting this category was relatively small compared with the transitioned union and MAST employees.

Q. Did the OSA cover the wages, salaries and terms and conditions of service for the Transitioned Employees that PSEG LI hired to satisfy its ServCo obligations?

A. Yes it did. Under the OSA, offers of employment to National Grid’s union employees were made at initial terms and conditions comparable to those set forth in the existing CBA, with recognition given to each union employee’s seniority. Union employees were also entitled to the benefits required under the applicable collective bargaining agreements. For example, all pension/401(K) benefits for union employees were continued with the same pricing, vendors, plan designs, and administrative provisions.

Q. How were offers of employment to National Grid's former MAST employees handled?

A. Offers of employment to MAST employees were also made at the same terms and conditions as salaries and benefits previously paid by National Grid. For MAST employees, however, we are transitioning them in due course from the former National Grid plan to the PSEG compensation structure. Consequently, as we will explain further below, the wages and benefits of union employees are governed by the existing CBA until its expiration, and we have made assumptions regarding union wage and benefits escalation factors for the remainder of the Rate Plan. For MAST employees, salaries and benefits included in the budgets have also been escalated based on certain assumptions described below.

III. UNION WAGES AND BENEFITS

Q. What does this section of your testimony address?

A. In this section, we will discuss the wages and benefits of the Transitioned Union Employees and the escalation of those rates during the Rate Plan years.

Q. What portion of PSEG LI's work force is unionized?

A. Approximately 67% percent of our approximately 2100 employees are members of IBEW Local 1049. The total wages and benefits for these workers are determined by collective bargaining.

Q. When does the existing CBA with IBEW Local 1049 expire?

A. As mentioned previously, the CBA will run through November 12, 2016. Until then, the contract remains in full effect and PSEG LI is obligated under the OSA to honor its terms and conditions.

Q. Please describe the wage increases provided for in the CBA.

A. The following wage increases will be granted to each eligible employee who is on the active weekly payroll on the effective date of that increase. Effective February 14, 2015, there will be a 2% general wage increase for all regular employees, in addition to a lump sum bonus of $500 to all IBEW Local 1049 represented employees on the property as of February 1, 2015. Effective February 14, 2016, there will be a 2.25% general wage increase for all regular employees covered by the CBA.

Q. You mentioned that the CBA will run through November 12, 2016. Are there requirements in the OSA that relate to the continuation of the CBA?

A. The OSA provides that prior to commencing negotiations with the IBEW regarding amendment or extension of the CBA, PSEG LI will advise LIPA of its negotiating objectives and any financial terms to be contained in the CBA, and will keep LIPA informed on the status of any negotiations.

Q. Because the existing CBA will expire in November 2016, have you escalated the union wage rates during the remaining period in 2016-2018?

A. Yes we have. Of course, it is not possible to know exactly how the results of the collective bargaining process will turn out. Consequently, we have applied the forecasted rate of inflation to the collective bargaining wage levels that will be effective on November 14, 2016, November 14, 2017 and November 14, 2018.

Q. Have you also escalated the cost of unionized employees' benefits over the Rate Plan years at the general rate of inflation?

A. No. The cost increases that were used for the administrative fees associated with benefits programs were escalated based on vendor contracts and fee agreements in place. With regard to medical and dental claims, we used a 6.6% increase for medical and a 6.7% increase for dental. The trend we are using is attributed to projections based on limited claims data for 2014 and the fact that we are operating with no historical data for these employees. These escalation factors are discussed further below.

IV. MANAGEMENT SALARIES AND BENEFITS

Q. Did you provide the current and projected MAST salaries and benefits to other groups preparing the budgets in a manner similar to that performed for the union employees?

A. Yes. In the same way that we provided the wage and benefit effects for unionized employees to the T&D, Customer Service, and Business Services organizations for use in preparation of their budgets, we provided information on salaries and benefits for all MAST and other non-union employees, including former National Grid and LIPA employees hired by PSEG LI, to those budgeting teams for the preparation of the budgets for the 2015 base year and for 2016, 2017 and 2018.

Q. You previously stated that PSEG LI's MAST employees are being transitioned from the National Grid compensation plans to the PSEG compensation plans. What consideration was given to the levels of salaries and benefits of the MAST employees when they were initially transitioned over to PSEG LI from National Grid?

A. As we observed previously, the salaries and benefits paid to MAST employees were the same as were paid by their previous employer National Grid. In this, PSEG LI was guided by the OSA. Offers of employment were made at terms and conditions designed to attract and retain the employees necessary to provide the services required by the OSA, considering among other things each Non-Union Employee's years of service, salary or wage level and bonus opportunity to which they were entitled immediately prior to January 1, 2014. Given the OSA requirement that ServCo provide competitive offers that both maximized the continuity of the workforce and considered existing salaries and bonuses, continuing the existing compensation structure of National Grid was the most appropriate way to satisfy that requirement.

Q. How did you determine compensation levels for newly hired employees?

A. For newly hired employees, we examined market data to ensure market competitiveness for the position in question. We also looked at similar positions within PSEG LI. Finally, we looked at inter-company equity within PSEG, to ensure, for example, that PSEG LI newly hired employees' compensation did not unduly differ from that paid to other PSEG employees in comparable roles.

Q. Please describe the compensation philosophy of PSEG LI.

A. PSEG LI's compensation philosophy is to establish competitive compensation opportunities for employees that align with compensation levels provided by other employers for similar roles and responsibilities. The primary objective of this philosophy is to enable the Company to attract and retain the services of a highly qualified workforce. This philosophy is consistent with that of many other utilities.

Q. Does the total compensation for PSEG LI's MAST employees include both base salary and a variable pay component?

A. Yes. PSEG LI's compensation philosophy is to measure and set a competitive total cash compensation opportunity (base salary plus variable pay) to levels found at other companies for similar roles and responsibilities. The variable portion of total compensation is considered pay at risk, in that it must be re-earned each year based on meeting pre-determined goals and operating targets.

Q. Is this compensation philosophy unusual in its inclusion of a variable pay component as part of total compensation?

A. No. Tying a portion of employees' total compensation to performance is commonplace both in American business generally and for public utilities, as well. The variable pay component of total compensation paid to PSEG LI's management employees is directly linked to specific measurable standards consistent with PSEG LI's goal of providing safe and reliable service to LIPA's customers. These performance goals encompass reliability, safety, customer service performance indicators, operating and capital budgets, and the timely completion of high priority capital and operating projects and programs.

Q. Please briefly describe the major elements of this incentive compensation plan.

A. The 2014 PSEG LI Performance Incentive Plan ("PIP") for MAST employees plan is designed with 60% linked to performance against the PSEG LI Balanced Scorecard,[1] 30% attributed to the PSEG LI business plan operating earnings and 10% to the PSEG-wide strategic goal known as "People Strong." The Balanced Scorecard is based on reliability, safety, operational measures and adherence to budgets, which are the primary metrics applicable to PSEG LI under the OSA. Our People Strong goal is designed to support a diverse and inclusive culture and measures retention, inclusion, diversity supplier spending and employee engagement. Such "customer-centric" metrics are used by many utilities in their incentive plans, as they are designed to reward employees for achieving goals around customer satisfaction, system reliability and availability, and operational excellence and align the interests of our employees and our customers. The 2014 PSEG LI PIP is aligned with the Company's vision and strategic business model and with the terms of the OSA, incorporating reliability, safety, operational, and financial goals.

Q. How do employees achieve incentive compensation under the PIP?

A. A participant's "target" payout is based on his or her Band/Grade, under which a target payout is modified by both the Company's and an individual's performance. Eligible employees must achieve satisfactory or better performance in order to participate. The size of the target bonus pool is the sum of all awards at "target"

[1] The Balanced Scorecard is presented in the Metrics Panel Testimony.

payout, i.e., participants' eligible base salaries, multiplied by their target percentages. Actual pool size will vary from target based on final goal results for the year.

Q. You mentioned that the PSEG LI PIP is aligned with the Company's vision and strategic business model. Are most of the compensable metrics under the PIP also metrics under the OSA?

A. Yes. Eighteen of the 21 compensable metrics (more than 80%) listed on the 2014 PSEG LI Balanced Scorecard are also OSA metrics and are, accordingly, directly related to PSEG LI performance. The remaining three metrics that are not OSA metrics are nonetheless aligned with and support customer benefits: Availability – Illness; Forced Automatic Outage Rate (Transmission); Damage Costs and Environmental Audit and Assessment Remediation Rate.

Q. Are such plans typical for utilities, including those regulated by the New York Public Service Commission?

A. Yes, they are. It is our understanding that the Public Service Commission has emphasized that it is not necessary to maintain an artificial distinction between compensation in the form of traditional pay and benefits and compensation that is incentive based, and has recognized that variable compensation and incentive plans are common management tools aimed at encouraging performance improvements.

Q. Please explain how you projected management salary expense for the three-year rate period 2016-2018.

A. We began with the MAST salary levels in the calendar year 2014, which were increased by an annual escalation factor of three percent for the years 2015, 2016, 2017 and 2018.

Q. What was the basis for your use of the three percent escalation factor?

A. The escalation factor was developed through a review of various compensation surveys of projected merit and total salary increase budgets, as well as a review of past history.

Q. Please describe the method used for escalating employee benefit costs for the Rate Plan years.

A. Given the lack of historical data, based on input from our consulting and vendor partners, the benefit projections were based on a few key assumptions:

- Medical and Prescription Drug: The 2014 medical and prescription drug costs were projected utilizing actual costs for the first six months of 2014 and estimating the claims for the second six months of 2014. The 2015 projections were based on the actual costs for the first six months of 2014 annualized to a full year and projected at an annual cost increase of 6.6%; increases for 2016 – 2018 were also projected at an annual cost increase of 6.6%, assuming no changes to employee contributions or plan design.
- Dental: The 2014 dental costs were projected using actual costs for the first six months of 2014 and estimated costs for the second six months of 2014. The 2015 projections were based on the 2015 renewal rate increase of 7% received from the vendor. For 2016, following the expiration of the existing vendor contract and based on the actual six months of claims experience presented, we assumed an increase of 15% based on an existing agreement. Increases for 2017-2018 were projected at an annual cost increase of 6.7%.

- Ancillary Benefits: We assumed a 3% increase for benefits administrative services at the expiration of the existing contract, beginning in 2017. For life and disability insurance costs and benefit consulting services, we assumed no increases.
- For the thrift saving 401(k) plan, which provides a Company match to management employees for a portion of their plan contributions, we used the labor escalation factor of 3%.

Q. Does the employee benefit expenses projection include any program changes?

A. No. The budgets prepared in this case assume no benefit plan design changes due to the existing CBA.

Q. Are escalation rates based on inflation assumptions likely to be accurate for escalation in health care costs?

A. No, they are not. Generally we expect health care cost inflation to outpace general inflation by a considerable margin. This is compounded by the fact that, for these particular employees, we are working with a very immature claim year and do not have sufficient historical claim data to determine the utilization or health profile of our employee population on Long Island. This makes it difficult to project our medical/Rx trend. We are, however, seeing larger increases due to our geographical location, and we know that increases in health care costs are being driven by increased utilization of medical procedures as well as the availability of new medical procedures, treatments, and devices. We also know that there are regulatory changes set to occur under the Affordable Health Care Act (“AHCA”) in 2018, which may impose a 40% excise tax on our health plans. The projections that we provide do not factor in this tax or the impact of the AHCA on our benefit program. Unfortunately, the final regulations regarding the calculation of the tax are not even expected to be available until 2017, so any projections we make at this time will be premature. Given the change in healthcare delivery and the regulatory environment, it is difficult to project trends over the next few years. Therefore, in light of the immature claims experience and the political uncertainties discussed above, it is difficult to develop a more accurate estimate of the increase in health care costs at this time. Consequently, we would need to adjust our actual experience when more data is available to us and the political and regulatory uncertainty surrounding the AHCA becomes settled.

Q. Does the projection for health care costs include known changes to the health plans as a result of the federal AHCA?

A. Yes, all of the required plan changes under the AHCA that are known to date have been addressed in the budget. The financial impact of the AHCA on the Company's health care costs assumes that there will be no additional plan changes to this legislation during the Rate Plan period. It is important to note that if the excise tax under the AHCA is imposed in 2018, the health care plans as they exist today would be subject to this 40% tax. This is our projection based on the limited direction provided under the regulations to date. Again, final direction will not even be provided until 2017.

V. EXECUTIVE COMPENSATION

Q. Previously you have discussed both union and MAST compensation but have not addressed Executive Compensation. Why is that?

A. Under the OSA, the term "Senior Management" means "the senior management level personnel employed by [PSEG LI]." This category comprises PSEG LI's President, Vice Presidents and Directors of the various organizations within PSEG LI and numbers approximately 18 individuals. The cost of Senior Management Compensation under the OSA is included in the fixed, annual Management Services Fee, which does not vary based on compensation paid to this group.

Q. Does this conclude the Panel's direct testimony at this time?

A. Yes, it does.

JUDGE PHILLIPS: The next panel?

MR. WEISSMAN: Thank you very much, Your Honors. Remaining direct and rebuttal testimonies that are not going to be cross examination, we will endeavor to provide all the remaining affidavits on the record tomorrow. Thank you very much.

JUDGE PHILLIPS: Thank you. We are turning to New York City now.

MR. GOODMAN: Thank you, Your Honors. First I have an affidavit for City witness John Marczewski. The affidavit describes his Prepared Direct Testimony which consist of 36 pages plus title page as well as prepared directed exhibits which include exhibit denominated as JJM-1 consisting of three pages and Exhibit JJM-2 consisting of 731 pages. I will note that although the latter was a single exhibit, it was transmitted to the secretary in three pieces for purposing of fitting within the transmission and upload to the DMM limitations.

Shall I move onto the affidavit of Dr. Horton?

JUDGE PHILLIPS: Yes.

MR. GOODMAN: Dr. Horton's affidavit describes his Prepared Pre-filed Direct Testimony which consists of 28 pages plus title page as well as prepared direct exhibits denominated as Exhibit RH-1 consisting of two pages, RH-2 consisting of 34 pages, Exhibit RH-3 consisting of 24 pages, Exhibit RH-4 consisting of 27 pages and Exhibit RH-5 consisting of 108 pages. Your Honor, I will note I have ready today the executed original affidavit for Marczewski. For Dr. Horton, I have a scanned copy of his executed affidavit, and I will provide originals shortly in a subsequent filing (handing).

JUDGE PHILLIPS: We have marked for identification the affidavit of John Marczewski as Exhibit 127. On that basis, we ask that his Prepared Direct Testimony consisting of 36 pages be copied into the record as though given orally today. We have also marked for identification the affidavit of Radley Horton, marked as Exhibit 128. On that basis, we ask that his prepared testimony consisting of 34 pages be copied into the record as though given orally -- correction, I believe that is 28 pages.

Before the
New York State Public Service Commission

In the Matter of

Long Island Power Authority and

Service Provider, PSEG Long Island LLC

Matter No. 15-00262

May 2015

Prepared Direct Testimony of:

John Marczewski, P.E.

On Behalf of:

The City of New York

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is John Marczewski. I am a Principal at Energy Initiatives Group, LLC ("EIG"). My business address is 29 Bartlett Street, Marlborough, Massachusetts 01752.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony before the New York State Public Service Commission ("PSC") on behalf of the City of New York ("City").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I hold a Bachelor of Science degree in Electrical Engineering from Worcester Polytechnic Institute, Massachusetts and a Master of Engineering in Electric Power Engineering degree from Rensselaer Polytechnic Institute, New York. I am a Registered Professional Engineer in several states. I am a member of the National Association of Professional Engineers, and a member of the Institute of Electrical and Electronics Engineers and its Power Engineering Society.

My past work includes assignments in development, engineering/design, construction, and operation of distribution, transmission, and generation projects. My experience also includes distribution and transmission system restoration activities following several major storms including Hurricane Gloria in 1985, through to Hurricane Sandy in 2012. I was Chair of the New York Independent System Operator, Inc.'s Operating Committee from 2009 to 2010, and Chair of the Transmission Planning Advisory Sub-Committee from 2007 to 2008.

Q. PLEASE DESCRIBE EIG'S ACTIVITIES IN ENERGY AND UTILITY ENGAGEMENTS.

A. Founded in 2000, EIG employs over 35 top industry professionals that provide a comprehensive range of consultative services to traditional utility companies, project developers, regulatory agencies, energy companies, financial organizations, transportation companies, government agencies, and a wide range of entities within the energy industry. EIG specialties include project and program management of large-scale generation, transmission, distribution, and substation projects, support for utilities during storm restoration efforts, and facility recovery.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PSC?

A. Yes. I provided written testimony and was made available for oral testimony at public hearings in Cases 13-E-0030, 00-F-0566, and 98-F-1968.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will cover three areas pertaining to how the Long Island Power Authority ("LIPA") and its service provider, PSEG-LI, LLC ("PSEG-LI") are addressing storm hardening and storm response. My testimony focuses primarily on the scope and adequacy of PSEG-LI's storm hardening plan, and it complements the discussion of climate projections presented by City witness Dr. Radley Horton.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Although LIPA has been committed to storm hardening since 2006, the average annual spend for storm hardening ($25 million per year) was low and expenditures were not tracked properly. Moreover, although there has been a significant surge in spending on system hardening post-Hurricane Sandy, that spending is constrained by federal grant limitations to specific elements of the LIPA system that were damaged by Hurricane Sandy. There is a pressing need for a comprehensive storm hardening collaborative that analyzes the system's needs on a holistic level, and I recommend that such a storm hardening collaborative be initiated as soon as this case concludes. The collaborative should utilize the most current climate projections and storm hardening design standards. The collaborative should focus on storm hardening the transmission system, substations, distribution system and transmission interfaces, and I make specific recommendations for each of these system components below.

In sum, although LIPA and PSEG-LI clearly are engaged in storm hardening efforts, they need to expand those efforts significantly. The storm hardening program should ensure that hardening and resiliency projects address vulnerable areas of the system that (i) perhaps were lucky enough to escape major damage from Hurricane Sandy, or (ii) were damaged by the storm, but the storm hardening projects needed to repair or replace those assets are ineligible for reimbursement from a federal grant. Although the City primarily is concerned that the electric system on the Rockaway Peninsula is hardened to withstand future weather events, I note that the information and recommendations presented in my testimony apply generally to the entire LIPA service territory.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I offer Exhibit__[JJM-1], which is my Curriculum Vitae, and Exhibit__[JJM-2], which is a compilation of the discovery responses from LIPA and PSEG-LI that I relied upon in preparing my testimony, some of which I expressly reference.

PSEG-LI/LIPA STORM HARDENING PLANS

Q. PLEASE PROVIDE AN OVERVIEW OF THE CURRENT LIPA AND PSEG-LI STORM HARDENING PLAN.

A. It is my understanding that PSEG-LI is implementing storm restoration or hardening work that primarily is related to Hurricane Sandy, with anticipated expenditures totaling approximately $1.4 billion. Based on PSEG-LI's responses to City-22 and City-23, it appears that approximately $705 million was designated to restore the system following Hurricane Sandy. That work, however, did not incorporate storm hardening design concepts except with respect to transmission line repairs and limited equipment elevation work at two flooded substations. As to the remaining $730 million, the vast majority of those funds apparently are designated to harden specific assets damaged by Hurricane Sandy. These amounts are directly related to grant monies applied for and received from the Federal Emergency Management Agency ("FEMA"), as well as additional funds awarded by FEMA but not yet received.

The Capital Budget Panel explained that the FEMA grant may be used only to reimburse "very specific elements of the Long Island electric system" that were damaged by Hurricane Sandy. Subject to this significant limitation, the FEMA funds may be used to elevate substation components, harden mainline distribution overhead lines, install up to 1,350 automated switching units ("ASUs"), harden certain distribution lines, and replace a "limited number" of transmission poles.

Importantly, PSEG-LI explained in its response to City-74 that the storm hardening plan is focused exclusively on work that may be reimbursed by the FEMA grant. If PSEG-LI currently is engaged in storm hardening work that does not pertain to the application of federal funds to assets damaged by Hurricane Sandy, its testimony and various discovery responses did not explain clearly the nature and scope of such work. In addition to ongoing work that is eligible for FEMA reimbursement, it appears that the same storm hardening measures implemented under the FEMA grant are applied to the installation of new and replacement equipment. This opportunism enables PSEG-LI to increase the deployment of hardened assets throughout the LIPA system. Although I generally agree with this approach, I am concerned that the constraints imposed by this strategy and the funding criteria of the FEMA grant are preventing the timely implementation of a comprehensive storm hardening program that addresses all elements of LIPA's electric system.

Q. HOW HAS THIS FUNDING IMPACTED THE UTILITY'S STORM HARDENING PLAN?

A. LIPA and National Grid (PSEG-LI's predecessor in operating LIPA's system) had plans in place since 2006 to address storm hardening at an average annual spend rate of approximately $25M per year. It appears that PSEG-LI essentially has suspended these previous storm hardening capital programs due to the scope and size of the FEMA-funded program. In terms of work budgeted for the 2016, 2017, and 2018 rate years as listed in Exhibit__[CBP-2], PSEG-LI has integrated several projects that appear related to, or would qualify for, use of the FEMA funds since they involve substation facilities damaged by Sandy. However, there does not appear to be any distribution storm hardening projects included in the total budget presented in that exhibit.

Q. WHY HAVE DISTRIBUTION PROJECTS IDENTIFIED FOR FEMA FUNDING BEEN LEFT OUT OF THE 2016, 2017, AND 2018 BUDGETS?

A. It is not entirely clear, but PSEG-LI states that it currently is engaged in a process to identify and develop a plan for distribution system hardening projects. PSEG-LI has engaged an engineering and design contractor to inspect targeted circuits for hardening, and will follow this effort with detailed designs to implement the hardening measures. The schedule indicated by PSEG-LI has the system survey and plan identification work completed by the end of 2015. Construction work will occur in 2016 and 2017, with some work expected to stretch into 2018. There also appears to be some substation storm hardening work which may not be part of the current capital budget.

Q. DO YOU AGREE THAT THIS TIMELINE IS REASONABLE?

A. The timeline does not seem unreasonable, but I do not understand why the work was not commenced closer in time to when the storm hardening program commenced in 2006.

Q. WHAT AMOUNT OF CAPITAL INVESTMENT WORK WAS EXPENDED AS PART OF THE ORIGINAL 2006 STORM HARDENING PROGRAM?

A. As discussed below, PSEG-LI has stated that annual storm hardening expenditures were not separately tracked prior to 2013. This makes it difficult to track which facilities have already been upgraded to standards consistent with current storm hardening practices. All facilities on the PSEG-LI system should ultimately be assessed to determine conformance with current storm hardening practices, as the FEMA-driven plans do not address facilities that were not impacted by Sandy even if those facilities may be vulnerable to future storms.

Q. DO YOU HAVE OTHER CONCERNS REGARDING THE CURRENT STORM HARDENING PLAN?

A. Yes. Initially, as described in response to City-52, LIPA committed in 2006 to a long-term storm hardening initiative. This decision was made well before storm hardening and resiliency became a focus of New York State utilities and regulators, and the LIPA Board of Trustees ("Trustees") should be commended for their proactive decision. LIPA and its service providers subsequently (and appropriately) expanded storm hardening budgets to maximize the receipt of available federal grant monies. Customers are benefitting from the increased capital investments enabled by those grants.

City-67 and City-68 indicate that the Trustees developed the framework of a comprehensive storm hardening and resiliency program that would address all aspects of the LIPA transmission and distribution ("T&D") system, if implemented fully over a proposed period of twenty years. The program included a suite of measures that would lessen the chance of storm damage, improve the ability of LIPA's system to withstand and recover from storm damage, and would cost almost $3 billion.

Although the proposed framework was more expansive, City-52 indicates that LIPA ultimately adopted a 20-year storm hardening program with a total budget of $500 million. I do not have sufficient information to opine on the total expenditures that should be designated for a comprehensive storm hardening program in LIPA's service territory, but an average annual spend of approximately $25 million seems disproportionately small given the scale of investment needed to have a timely and meaningful impact in a large service territory with significant coastal storm exposure.

Q. PLEASE EXPLAIN.

A. The response to City-90 included the "Update on LIPA's Storm Hardening Initiatives 2007-2012" that Navigant Consulting presented to the Trustees in December, 2012. This report explains that, in 2006, Navigant compiled over two dozen storm hardening initiatives "for potential application on Long Island." Navigant estimated that it would cost approximately $3 billion to implement all initiatives at the locations most vulnerable to a Category 3 hurricane. LIPA opted for a $500 million program, and the information provided to date does not explain why the Trustees determined that a $25 million average annual budget might be the appropriate annual spending level.

Neighboring utilities provide two additional points of reference for the potential scale of utility storm hardening investments. Consolidated Edison Company of New York, Inc. ("Con Edison") plans to spend approximately $724 million on electric system storm hardening from 2014 through 2016. PSE&G has estimated that it will spend approximately $1.3 billion on transmission system hardening projects alone, and likely will spend hundreds of millions more (if not $1 billion) to harden its distribution system. Although spending under the FEMA grant is grossly comparable to the Con Edison and PSE&G expenditures noted earlier, the FEMA work is too restricted and should be expanded.

Q. HAS LIPA SPENT MORE THAN $25 MILLION ANNUALLY SINCE THE STORM HARDENING PROGRAM COMMENCED?

A. I don't know, and apparently neither does LIPA. PSEG-LI explained in response to City-52 that details of the storm hardening program "have not been historically well tracked." In fact, annual storm hardening expenditures were not specifically tracked prior to 2013.

Navigant reported to the Trustees in 2013 that the "storm hardening portions of most capital projects cannot be readily identified in available documentation." Navigant explained that the 2007 to 2012 capital expenditure documents do not include details on storm hardening investments including the scope of storm hardening efforts, the incremental cost of storm hardening, storm hardening allocations applied to total project costs, and applicable storm hardening recommendations.

Without hard cost data, Navigant attempted to estimate how much LIPA invested on storm hardening projects from 2006 through 2012. This analysis used allocation factors to estimate the percentage of project investment that might correspond to storm hardening. Based on this analysis, Navigant estimated that LIPA spent an average of approximately $41 million annually from 2006 through 2012.

Q. DO YOU CONSIDER NAVIGANT'S ANALYSIS TO BE A RELIABLE INDICATOR OF HOW MUCH LIPA INVESTED ON STORM HARDENING PROJECTS BEFORE 2013?

A. No. The use of allocation factors to estimate the amount of storm hardening investment in a given project makes the analysis highly-dependent on the accuracy of the allocation factors. It is unclear how Navigant validated the allocation factors that it used, or even if such validation could be made, given that there is no documentation available to corroborate or validate the allocations.

It is possible that LIPA's average annual spending on storm hardening projects exceeded $25 million by some increment. However, even assuming for the sake of discussion that Navigant's estimate is reasonably accurate, and the annual average spend on storm hardening was approximately $40 million, this level of spending still appears to be small relative to the scope of investment needed to harden the assets that are most vulnerable to a Category 3 hurricane.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE DOCUMENTATION OF PAST STORM HARDENING INVESTMENTS?

A. It is alarming that LIPA and its previous service provider failed to maintain clear records of a major capital initiative. The lack of such records makes it difficult to detail the storm hardening and resiliency work completed prior to 2013, or the remaining scope of work that must be completed on LIPA's system. The incomplete records also make it difficult to understand how the work that has been completed fits within the overall framework of the comprehensive storm hardening program that Navigant presented to the Trustees.

Q. PLEASE CONTINUE.

A. The foregoing concerns are not necessarily intended to criticize past decisions, but to illustrate how those decisions may have impeded progress on hardening LIPA's system against future weather events. For instance, PSEG-LI explained in response to City-72 that detailed plans to harden the distribution system on the Rockaway Peninsula are being developed shortly, and were not prepared during the first eight years of the storm hardening program. Because the developing plans are for projects that will be supported by the FEMA grant, the projects presumably will be limited in scope to satisfy the FEMA grant requirements, and will not address the distribution system on a holistic basis.

Q. DO YOU HAVE ANY OTHER GENERAL CONCERNS REGARDING THE CURRENT STORM HARDENING PROGRAM?

A. The program includes routine maintenance work such as vegetation management, hazard tree removal, and the replacement of deteriorated poles. These activities are essential to maintaining a reliable system and should be prioritized, but they are matters of routine system maintenance. LIPA and its service providers, including PSEG-LI, presumably have been required to engage in these activities to satisfy applicable reliability and other regulatory standards on a routine and ongoing basis. I agree that these routine maintenance activities have an ancillary storm hardening and resiliency benefit, but I disagree that they should be characterized as storm hardening projects.

STORM HARDENING AND RESILIENCY

Q. DO YOU HAVE SPECIFIC CONCERNS REGARDING THE STORM HARDENING DESIGN STANDARDS AND PRACTICES THAT LIPA AND PSEG-LI ARE RELYING ON?

A. Yes. In the following sections, I discuss storm hardening plans for the transmission system, substations, and distribution system, as well as the need to harden the gas and liquid fuel supply systems and the transmission interfaces with Con Edison, Eversource Energy (formerly Northeast Utilities), and other merchant transmission facility owners. The following discussion recommends enhancements and modifications to these areas. Although the City's primary interest lies in the Rockaway Peninsula, most of my recommendations apply generally to the entire LIPA service territory. I also recommend a collaborative process to expand the current storm hardening program.

1. STORM HARDENING AND RESILIENCY COLLABORATIVE

Q. DO YOU HAVE ANY GENERAL COMMENTS REGARDING THE CURRENT STORM HARDENING PROGRAM?

A. I explained earlier that the current storm hardening program is focusing a large amount of federal funding on a relatively narrow slice of the storm hardening and resiliency investments that are needed. Those projects are further limited in scope insofar as the grant money may be applied only to assets that were damaged by Hurricane Sandy. I agree that damaged assets should be replaced with hardened upgrades, but the fact that equipment was not damaged by Hurricane Sandy does not mean that it is not vulnerable to damage by a future weather event. For instance, a future storm of comparable (or greater) intensity to Hurricane Sandy could impact a different population of system assets if it advances over Long Island via a different trajectory or at a different rate. A singular focus on hardening assets damaged by the last storm will leave the system vulnerable to potentially-extensive damage from future storms.

Q. SHOULD THE CURRENT STORM HARDENING PROGRAM BE EXPANDED TO ADDRESS THIS VULNERABILITY?

A. Yes. The scope of current storm hardening and resiliency work should be expanded to prioritize for hardening all at-risk assets that are not eligible for federal reimbursement. PSEG-LI should extend its system survey to include all of its transmission, substation, and distribution facilities. As additional work is identified beyond projects eligible for FEMA funding, PSEG-LI should integrate this work into its near-term capital budgets so that the entire system can benefit from up-to-date storm hardening practices. Although areas that have already experienced reliability problems present a good place to start storm hardening efforts, they should not be the sole focus of such work.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING HOW THE EXPANDED PROGRAM SHOULD BE DEVELOPED?

A. Expanding the storm hardening program will require a substantial effort. The underlying design standards should be reviewed and updated (a point that I discuss later in my testimony). To inform investment priorities, LIPA and PSEG-LI will need to improve their projections of future climate conditions and assess the climate vulnerability of its system based on the best available projections of sea level rise, flood risk, temperature change, and other climate variables. The expansion also should accommodate stakeholder participation and input. Therefore, it is my recommendation that the Trustees commence a collaborative process to develop this expanded program and supporting information.

Q. IS THERE A PRECEDENT FOR SUCH A COLLABORATIVE?

A. Yes. The PSC directed Con Edison to administer a similar process in Case 13-E-0030. That collaborative was interactive and productive, and contributed to an appropriate change in utility practice that integrated resiliency considerations into all system planning, design standards, and construction practices. It also provided the utility with important feedback regarding the scope and pace of storm hardening investments, and provided guidance on the continuing development of Con Edison's storm hardening and resiliency program. The Con Edison collaborative provides a model for the collaborative stakeholder process that LIPA should initiate.

Q. WHEN SHOULD THE TRUSTEES INITIATE THE COLLABORATIVE?

A. The collaborative should commence as soon as possible. The Trustees should begin contacting stakeholders that may be interested in joining the LIPA storm hardening collaborative and otherwise begin setting the stage for that initiative. There is not sufficient time in the instant phase of this proceeding to accommodate a parallel collaborative process that likely will include the development and evaluation of various studies and analyses, but the collaborative could begin to meet when all post-hearing briefs have been filed, and the parties' substantive work in this proceeding is complete. The collaborative should proceed in a deliberate but expeditious manner.

Q. WHY IS IT NECESSARY FOR THE COLLABORATIVE TO START DEVELOPING A COMPREHENSIVE STORM HARDENING PLAN AT THE EARLIEST POSSIBLE DATE?

A. Utilities should plan their systems to address current and future needs. Most utility assets are long-lived, meaning that they will remain in service for many decades. The assets also can be very expensive, making it undesirable to replace them before they reach the end of their useful lives. Accordingly, when designing new infrastructure, renovations and repairs, although utility system planners should take into consideration the immediate and direct needs for infrastructure, they should also consider future needs such as load growth, resiliency, the nature of the area in which the infrastructure will be installed, and other salient details. With respect to resiliency, such planning should address current climate projections and not merely react to the storm that already hit. City witness Dr. Radley Horton discusses the climate variables that should be addressed in such planning.

On a daily basis, the utility is assessing infrastructure needs and designing and constructing the projects that will address those needs. Delaying the implementation of a truly comprehensive storm hardening program means that costly and long-lived assets may be installed that do not reflect appropriate storm hardening design standards and concepts. Although such hardening and resiliency benefits potentially may be achieved via projects to retrofit those assets, it is preferable and more cost-effective for capital projects to reflect storm hardening design concepts and standards in the first instance.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS REGARDING THE PROPOSED COLLABORATIVE?

A. One key feature of the storm hardening program is the concept that it is designed to address potential future weather conditions. The design criteria and standards embedded in the program necessarily must reflect future climate conditions that may be different from current conditions. My testimony and the testimony of City witness Dr. Horton explain that certain storm hardening design standards, climate projections and climate-related metrics adopted by PSEG-LI need to be updated. Importantly, those inputs need to be reviewed and updated periodically, as new information is developed and climate models are improved.

Q. HOW DID THE COLLABORATIVE IN CASE 13-E-0030 ADDRESS THESE NEEDS?

A. The PSC directed Con Edison to undertake a climate vulnerability study as part of the collaborative. This study is intended to provide a long-range basis for the ongoing review of storm hardening design standards. As proposed recently by Con Edison, the climate change vulnerability study will address how each of the following impacts of climate change will impact its facilities: temperature and humidity; temperature variability and load; precipitation; extreme events; and sea level rise and coastal storm surge flooding.

Q. DO YOU RECOMMEND THAT LIPA RETAIN A CONSULTANT TO PERFORM A SIMILAR STUDY AS PART OF THE AUTHORITY'S STORM HARDENING AND RESILIENCY COLLABORATIVE?

A. Yes. The specific scope of the study should be developed as part of the collaborative process, but the climate vulnerability study that the PSC directed Con Edison to complete provides a useful model for the study that LIPA should complete, and update periodically.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS REGARDING THE EXPANDED STORM HARDENING PROGRAM?

A. LIPA and PSEG-LI should begin soliciting the external contractor and other resources that will be needed to implement the expanded storm hardening program. This effort should begin sufficiently in advance of when the expanded program commences that the ramp-up in external resources may coincide with the ramp-up in storm hardening work.

2. <u>STORM HARDENING – TRANSMISSION SYSTEM</u>

Q. HOW ARE STORM HARDENING DESIGN CONCEPTS INCORPORATED INTO TRANSMISSION SYSTEM PROJECTS?

A. PSEG-LI explained in response to City-9 that all new transmission lines are designed to withstand Category 3 hurricane force winds of 130 miles per hour. Poles installed in flood zones are buried a foot deeper than normal, and steel poles with concrete bases are utilized along rights-of-way and Long Island Rail Road lines. When poles are replaced, PSEG-LI installs a pole that is two class sizes larger than the replaced asset.

Q. ARE THESE MEASURES ADEQUATE AND APPROPRIATE?

A. These measures address and enhance the ability of the physical transmission line and its structures to withstand higher wind loads than what may have been used as the original design criteria when the lines were first constructed. However, to be effective, ultimately the entire transmission line segment should be designed to these standards so that no weak links exist along the line's route. Also, structural design loads should be calculated to include the effects of storm-related situations, such as broken conductors or shield wires, and their impacts on structure loads.

Q. WHAT OTHER DESIGN STANDARDS AND CRITERIA SHOULD BE REFLECTED IN TRANSMISSION SYSTEM PROJECTS?

A. In addition to the physical strengthening of structures, the impacts of other storm-related conditions should also be assessed. This can include ensuring proper electrical clearances for conductor blowout with the higher wind speeds, mitigation of conductor motion such as galloping which may occur under certain conditions, protection from failures of adjacent structures or impacts of objects along the right of way, and in areas where storm surge flooding may occur, protection from the impacts of floating objects which may include boats and other large or heavy floating debris that may be carried by the floodwaters. Also, given the critical nature of some transmission lines which may be on multiple circuit structures, PSEG-LI should evaluate separating lines onto their own structures to mitigate the possibility of multiple circuit outages arising from the failure of a single structure.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING TRANSMISSION SYSTEM STORM HARDENING?

A. Yes. PSEG-LI explained in response to City-34 that its current storm hardening program does not address the 69 kV transmission system that serves the Rockaway Peninsula. In its response to City-73, PSEG-LI clarified that current hardening efforts "are being considered only for new facilities or for the expansion of existing facilities." PSEG-LI did not explain why it is not now attempting to harden existing transmission assets. I assume this relates to the fact that the current program is limited to investments in equipment that was damaged by Hurricane Sandy and, therefore, may be reimbursed by the FEMA grant.

Q. WHAT RISKS ARE ASSOCIATED WITH FAILING TO HARDEN THE TRANSMISSION SYSTEM?

A. The Rockaway Peninsula was devastated by Hurricane Sandy. Although I appreciate the need to capture all federal funds that may be directed toward storm hardening projects, I already have explained why limiting the storm hardening program to assets damaged by Hurricane Sandy – as required by the FEMA grant – leaves many portions of LIPA's electric system vulnerable to weather-related outages.

It is a question of when, not if, a storm that equals or exceeds Hurricane Sandy impacts the LIPA service territory again. Even a storm of lesser intensity could have an equal or greater impact if, by chance, a combination of storm trajectory and other variables concentrate the storm surge, wind and rain on sections of the electric system that have not been hardened because (by random chance) they were not damaged previously by Hurricane Sandy. The risks associated with failing to harden the transmission system were illustrated by Hurricane Sandy, which caused approximately 1.2 million customer outages with an average restoration time of approximately 14 days.

3. <u>STORM HARDENING – SUBSTATIONS</u>

Q. HOW ARE STORM HARDENING DESIGN CONCEPTS INCORPORATED INTO SUBSTATION PROJECTS?

A. PSEG-LI explained in response to City-9 that it will avoid locating new substations in flood zones "or design appropriate control measures such as raised equipment." New substations will be designed to withstand Category 3 hurricane force winds of 130 miles per hour. Pursuant to the constraints of the FEMA grant, PSEG-LI also is elevating substation equipment that was damaged during Hurricane Sandy. The extent to which PSEG-LI is hardening existing substation equipment that was not damaged by the storm is unclear.

Q. WHICH ROCKAWAY SUBSTATIONS HAS PSEG-LI IDENTIFIED FOR STORM HARDENING WORK, INCLUDING WORK ALREADY COMPLETED AS PART OF POST-SANDY RESTORATION EFFORTS?

A. The substations on the Rockaway Peninsula that are involved in FEMA-funded storm hardening work are Far Rockaway, Arverne, and Rockaway Beach. Hurricane Sandy also damaged the Neponsit substation, but that facility was retired from service instead of being repaired because its load could be served from the remaining substations. Storm hardening projects at those substations primarily involve the installation of new switchgear and control enclosures at higher elevations above anticipated flood levels.

Q. ARE THESE MEASURES AND PROJECTS ADEQUATE?

A. It is unclear.

Q. PLEASE EXPLAIN.

A. PSEG-LI has provided inconsistent statements regarding plans to harden the substations that serve the Rockaway Peninsula. In response to City-34, PSEG-LI explained that it has no plans to harden those substations. In response to City-74, however, PSEG-LI made a vague reference to flood protection measures that will be installed at those locations. City-26 and City-89 specify that certain switchgear and/or control enclosures will be elevated at the Rockaway substations. It thus appears that hardening work at substations is proceeding to the extent that it is eligible for FEMA reimbursement. Based on the information provided, however, this work apparently is only part of the hardening measures that should be evaluated and implemented.

Q. PLEASE CONTINUE.

A. All critical substation equipment, generally, and energized equipment, specifically, should be elevated to a height that reflects a certain margin of error to protect against water levels greater than what actually has been experienced. This "freeboard" is the marginal height of wall or elevation provided above the design flood level and is intended to accomplish design objectives while allowing for uncertainty in a water surface profile. A uniform freeboard standard should be adopted and applied to all flood wall and equipment elevation projects.

City-67 explains that substation hardening could include projects that raise the foundations of numerous equipment classes (including, but not limited to, switchgear, circuit breakers, and control enclosures); secure equipment and structures; rebuild with a flood-resistant design; and develop or modify standards for substations located in low lying areas. I agree that these measures should be considered for implementation at all substations on a site-specific basis. Most of these measures, however, apparently are outside the scope of the FEMA grant. Consequently, most of these measures also appear to be outside the scope of the current storm hardening program. The storm hardening and resiliency collaborative should develop recommendations as to the measures that should be installed at each substation based on flood risk and other pertinent factors.

Q. DO YOU HAVE ANY SPECIFIC CONCERNS REGARDING THE STANDARDS THAT PSEG-LI HAS APPLIED TO ELEVATING SUBSTATION EQUIPMENT?

A. Yes, I have three concerns.

Q. WHAT IS YOUR FIRST CONCERN?

A. Critical equipment should be elevated to a height that is based on uniform standards and the best data available. I understand from City witness Dr. Horton that the FEMA Best Available Flood Data (6/13/13) are the best data available with respect to flood risk. PSEG-LI is relying on those maps for some, but not all, substation elevation projects. PSEG-LI should rely only on the latest flood maps, which will change over time. The company also should re-evaluate elevation projects based on the older maps to determine whether incremental increases in substation equipment are needed.

Q. DO YOU HAVE A RELATED CONCERN REGARDING THE FLOOD MAPS USED TO DESIGN SUBSTATION PROJECTS?

A. Based on information from PSEG-LI, substations in the Rockaway Peninsula which suffered storm damage during Sandy will be hardened using the latest FEMA flood data with one exception, Arverne. This substation was rebuilt before the latest FEMA data was available, and instead was hardened to an elevation based on Sandy flood levels. Now that the FEMA data has been updated and is available, Arverne should be considered for additional hardening work if the new FEMA flood levels exceed those of Hurricane Sandy, which appears to be the case.

Q. WHAT IS YOUR SECOND CONCERN?

A. Substation work will include elevating equipment and installing flood control walls. It does not appear, however, that relevant storm hardening projects reflect a uniform freeboard value, and the design standards underlying the elevation projects do not explicitly account for future sea level rise. Although each substation is different and may include features that warrant a larger or smaller freeboard, the projects generally should reflect a consistent and uniform standard that also accounts for future sea level rise.

Q. PLEASE EXPLAIN HOW THE STORM HARDENING PROJECTS REFLECT AN INCONSISTENT FREEBOARD STANDARD.

A. As explained in City-26, the FEMA maps applicable to the Arverne Substation indicate a 10 foot design water level. One set of switchgear at the substation was raised to an elevation of 10.9 feet (that is, reflecting a freeboard value of 0.9 feet), and a second set of switchgear was elevated to 12.75 feet (that is, reflecting a freeboard value of 2.75 feet). PSEG-LI does not explain how it selected the design safety margin, or why it selected disparate margins for comparable equipment at the same substation.

At the Barrett and Fair Harbor Substations, PSEG-LI adopted freeboard values of 7.35 feet and 0.6 feet, respectively. A similar inconsistency was noted for elevation projects at the Woodmere Substation, although a single freeboard value of 3.5 feet was applied to three separate elevation projects at the Far Rockaway Substation.

These differences in freeboard values may reflect a physical constraint or other compelling circumstance that warrants deviating from a freeboard standard. Barring such physical constraint or compelling circumstance, however, the design safety margin should be uniform for all equipment elevation projects and flood control walls.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE FREEBOARD THAT SHOULD BE REFLECTED AT EACH SUBSTATION?

A. In Case 13-E-0030, the City advocated that Con Edison should adopt a uniform freeboard value of three feet above the design default value (*i.e.*, “FEMA+3”). Con Edison ultimately adopted, and is applying, this standard as a uniform component of relevant storm hardening projects.

FEMA also has issued guidance and requirements regarding equipment elevation standards. The Federal Flood Risk Management Standard ("FFRMS") is based on Executive Order 11988 and provides that a "climate-informed science approach" to mitigating flood risk is preferred. Alternative approaches include using freeboard, the 500-year flood elevation, or a combination of approaches.

The City agrees that a climate-informed science approach to system planning and design is ideal. The City continues to believe that FEMA+3 is an appropriate standard, but acknowledges that it does not explicitly account for future sea level rise. The storm hardening collaborative that I recommend should examine the issue to determine what freeboard or other elevation standard accounts for an adequate amount of sea level rise, includes a design safety margin, and satisfies all applicable design standards and funding requirements.

Q. WHAT IS YOUR THIRD CONCERN REGARDING THE EQUIPMENT ELEVATION PROJECTS?

A. Ideally, all critical substation equipment would be protected against inundation by flood waters via elevation, and not flood control walls. Critical substation equipment generally includes, at a minimum, any asset that is energized. It appears from the information provided by PSEG-LI that the elevation projects at each substation address a subset of the equipment that should be elevated as a storm hardening measure. As noted above, such equipment includes, but is not limited to, switchgear and control enclosures.

It is not clear whether all critical equipment has been or will be elevated at each substation. If this work has been completed or is planned, then PSEG-LI should clarify the scope of work. If this work has not been completed and/or is not planned, then PSEG-LI should expeditiously complete this essential component of substation storm hardening.

Q. ARE THERE OTHER CONSIDERATIONS THAT SHOULD BE INCLUDED IN HARDENING SUBSTATION EQUIPMENT AGAINST STORMS OR OTHER WEATHER RELATED EVENTS?

A. It is important that all critical equipment be included in the scope of storm hardening projects at substation facilities. In particular, control houses (which may include "control enclosures" in PSEG-LI's nomenclature) should be built so that their floor level is above the design flood level with sufficient freeboard and an additional margin to account for sea level rise, as discussed above. They should also be designed to withstand the wind loads caused by 130 MPH winds consistent with the PSEG-LI standard for substations and transmission lines. Further, given that new control equipment for substations is microprocessor-based and contains sensitive electronics, wind resilience should also extend to watertight construction so that wind driven rain does not enter the control house. Finally, sufficiently-sized cooling and HVAC equipment, suitably designed for protection from the stated storm conditions, should be included and also take into account future trends for warmer summer ambient temperatures. I would suspect that all control houses/enclosures in storm hardened substations will be designed to these general criteria, but information provided in this proceeding is not sufficient to determine if these measures are being applied in all cases.

Q. WHY DO YOU BELIEVE THAT EQUIPMENT ELEVATION IS THE PREFERRED SOLUTION TO FLOOD CONTROL WALLS?

A. The best method of ensuring that no equipment is overcome by floodwaters is to elevate it above the highest projected flood elevation. This method will work 100 percent of the time, provided that the floodwaters stay below the design level. Barrier walls, even when well designed, are only as good as their weakest link. Water will use any path available to enter the walled-in area. When this occurs, the entire barrier wall system is rendered ineffective. This is a significant concern. Flood water, especially under hydrostatic pressure, can find its way through conduit and duct systems, storm drains, and even through porous fill and flood the walled-in area from below. These areas may have been sealed off when the wall system was first installed. However, unless these seals are inspected, tested, and maintained over time, the risk that water will penetrate a walled-in area increases as the system ages. Therefore, for critical facilities, it is recommended that equipment elevation be the primary method used for storm hardening.

Q. HOW DOES THE AVAILABILITY OF NEIGHBORING SUBSTATIONS AFFECT SERVICE TO THE ROCKAWAY PENINSULA?

A. The electric supply to the Rockaway Peninsula includes 69 kV transmission and 33 kV subtransmission circuits. These circuits are ultimately sourced from facilities located off of the peninsula. In light of this configuration, outages at these neighboring substations and on connecting transmission and subtransmission lines could potentially affect electric supply to the Rockaway Peninsula.

Q. IS PSEG-LI IMPLEMENTING, OR PLANNING TO IMPLEMENT, ANY STORM HARDENING PROJECTS AT THOSE NEIGHBORING SUBSTATIONS?

A. One of these substations (Woodmere) is adjacent to a tidal waterway and would be vulnerable to coastal flooding. PSEG-LI has indicated that it plans to install new switchgear and raise the control enclosure at the Woodmere substation to mitigate this risk. Other key substations are inland and located along a corridor owned by the Long Island Rail Road. They do not appear to be in locations that are susceptible to coastal flooding.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS REGARDING STORM HARDENING PROJECTS THAT ENSURE RELIABLE ELECTRIC SERVICE TO SUBSTATIONS ON THE ROCKAWAY PENINSULA?

A. The Rockaway Peninsula lies at the southwestern limit of the PSEG-LI system. It consequently has limited options for redundant and geographically diverse transmission or subtransmission supply connections. For this reason, it is essential that LIPA and PSEG-LI ensure that the existing transmission supply to the Rockaway Peninsula is hardened to the extent practicable. This initiative should include a focus on locations where both 69 kV lines supplying the area share a common pole or structure. Those locations should be eliminated to the extent practicable so that a single failure cannot compromise two transmission lines. Overall, this effort should reduce the risk that a single contingency or equipment failure is able to cause a long-term outage for tens of thousands of customers.

PSEG-LI, however, currently does not have plans to address vulnerabilities associated with transmission service to the Rockaway substations. This may represent a prime example of critical storm hardening work that is not being implemented because it is not eligible for reimbursement by the FEMA grant.

Q. IS THE WIND SPEED DESIGN CRITERIA OF 130 MILES PER HOUR ADEQUATE TO HARDEN SUBSTATION EQUIPMENT AGAINST FUTURE WEATHER EVENTS?

A. The criteria seems reasonable based on historical events, but historical weather patterns are not necessarily reliable predictors of future weather in a changing climate. This issue is addressed further by City witness Dr. Horton.

Q. ARE THERE OTHER RESILIENCY MEASURES THAT SHOULD BE INCLUDED IN PSEG-LI'S STORM HARDENING PLAN?

A. Probably. The difficulty in answering this question, however, is that PSEG-LI and LIPA apparently are not implementing a comprehensive plan to harden the Authority's electric system against future climate events and other vulnerabilities. I noted earlier that storm hardening investments were not specifically tracked prior to 2013. This makes it difficult to understand what has been done and, therefore, presents a challenge in evaluating what storm hardening work remains to be done.

That said, there are numerous measures and standards that could be included in a comprehensive storm hardening program. My testimony identifies a handful of such options that should be deployed as part of a comprehensive program. The collaborative should explore additional measures and alternatives.

4. STORM HARDENING – DISTRIBUTION SYSTEM

Q. HOW DOES THE STORM HARDENING PROGRAM ADDRESS THE DISTRIBUTION SYSTEM?

A. PSEG-LI explained in response to City-35 that it does not have a comprehensive storm hardening plan for the distribution system, and that the evaluation process to develop such plan is only just beginning.

Q. IS PSEG-LI OR LIPA TAKING ANY ACTION TO HARDEN THE DISTRIBUTION SYSTEM AGAINST FUTURE CLIMATE EVENTS?

A. Yes. As noted above, the federal grants are supporting a limited scope of distribution hardening projects. It also appears that PSEG-LI is applying the design standards from those projects to the new installation or replacement of certain distribution assets that were not damaged by Hurricane Sandy.

More specifically, PSEG-LI explained in its response to City-4 that distribution system hardening projects include a narrow profile construction for certain distribution poles, and selecting more robust poles that are buried one foot deeper than normal. PSEG-LI also is installing ASUs on distribution circuits damaged by Hurricane Sandy.

The City agrees that these measures will improve the resiliency of the distribution system to an extent that is commensurate with the deployment of those assets. The narrow profile construction and upgraded poles will enhance the ability of distribution poles to withstand significant weather events. ASUs will reduce the number of customers that lose service when there is a fault on the upgraded circuit. System resiliency will improve gradually as these assets replace older equipment, although the resiliency benefit will be limited by the rate at which new poles and ASUs are installed, and the extent to which they saturate potential installation sites. This is another limitation of a program that seemingly is focused on replacing assets damaged by Hurricane Sandy rather than a holistic approach to system resiliency.

Q. IS PSEG-LI PROPOSING OTHER MEASURES TO HARDEN THE DISTRIBUTION SYSTEM?

A. Yes. PSEG-LI has also proposed replacement of energized high voltage feeder conductors on its open wire pole lines with 336 kCmil covered aluminum conductor for mainlines and to replace open wire secondary cables (which are operated at lower voltages and connect to individual customer services) with insulated triplexed cable (three low voltage conductors wound together in one assembly). Eliminating open wire secondary construction will harden the system at or near the customer level. Replacing smaller-sized mainline high voltage feeder conductors will also yield an improvement in resiliency (particularly if existing conductors are older copper conductors which may have reduced breaking strength due to age or heating), and the use of covered conductor, even if only partially insulated, will also help guard against outages from incidental tree branch contacts.

Q. ARE THERE ADDITIONAL DESIGN STANDARDS THAT PSEG-LI SHOULD INCORPORATE IN ITS STORM HARDENING PROGRAM?

A. Yes.

Q. PLEASE EXPLAIN.

A. Neither the rate filing nor discovery responses indicate that the storm hardening program includes certain resiliency measures frequently used by other utilities. For instance, spacer cable, aerial cable, and insulated tree wire often are used to harden distribution systems against weather-related outages. PSEG-LI explained that it soon will begin developing a distribution storm hardening plan for the Rockaway Peninsula. That process should evaluate where these assets may be deployed to improve distribution system resiliency. The collaborative also should examine this issue.

Q. WHY SHOULD SPACER CABLE BE INCLUDED IN THE STORM HARDENING PROGRAM?

A. PSEG-LI should evaluate the benefits and cost of replacing open-wire conductor and covered conductor on lower-profile cross-arms with overhead spacer cable. This cable consists of non-shielded, non-tensioned, insulated conductors, supported in a close triangular configuration by insulating spacers from a high strength messenger/neutral wire. Overhead spacer cable can resist most outages because its energized conductors are partially insulated and, therefore, less likely to have a short circuit when in contact with trees. The high strength messenger wire which supports the spacer cable system can protect the energized conductors it supports from fallen tree limbs, and can isolate and protect energized conductors from mechanical loads that otherwise might lead to breakage. It also can remain energized even after its supports are severely damaged, or in some cases if it gets entangled with other equipment. For this reason it frequently is installed in areas that are heavily treed, or require close clearances. The long-term benefits provided by these operational characteristics have led many small municipal electric utilities to select overhead spacer cable on an almost universal basis, notwithstanding that it is more costly than an open bare wire configuration.

Q. WHY SHOULD AERIAL CABLE BE INCLUDED IN THE STORM HARDENING PROGRAM?

A. Aerial cable is best-suited for express mainline runs that terminate in other types of primary construction. Aerial cables are fully-insulated power cables that are essentially the same types of cables that are used for underground installations. However, instead of being installed in an underground conduit system, the cables are lashed to a messenger wire and suspended from poles. Mid-line connections cannot be easily made to these cables because they are fully-insulated. However, they do provide an alternative type of construction that has a very narrow profile and can resist outages due to tree limb contacts, and can be used to create storm-resilient sections of mainline feeders. City-68 also identifies aerial cable as an option to harden roadside transmission lines at 33 kV and below in heavily treed areas. LIPA clearly has considered this measure, although neither LIPA nor PSEG-LI has explained whether aerial cable will be deployed, or if not, why not.

Aerial cable does have certain drawbacks, however. As mentioned above, it is most suitable for express runs where loads are not tapped off along its route. A typical distribution feeder has many customer load taps along its route. It is relatively easy with typical work practices involving work on energized lines to make new connections to feeders with this type of construction without de-energizing the entire section of the line to add customers or make other changes. This is advantageous for many reasons, including that it allows disruptive customer outages to be avoided. Since aerial cable is fully insulated as compared to open wire construction, covered conductor, or spacer cable construction, tapped connections on aerial cable cannot be made without removing the insulation system in the area of the connection and installing cable to air terminations. This activity requires an outage of the cable for the duration of the work. However, if the feeder being considered for hardening is an express run – that is, it has no load connections between the start and end of the cable section – aerial cable may be a good choice due to its resilience and compact profile.

Q. WHY SHOULD INSULATED TREE WIRE BE INCLUDED IN THE STORM HARDENING PROGRAM?

A. Partially-insulated conductors covered with insulating material designed to be resilient against tree branch contact and related physical wear can be useful in overhead distribution line applications, especially for single phase or two phase taps. These sections of overhead lines are not part of a feeder's mainline (which will be three phase), but can still serve significant load areas and would benefit from protection against tree-related outages that can occur in areas where bare conductors are used. PSEG-LI should identify areas that are susceptible to tree-related outages and evaluate the benefit and cost of installing tree wire at those sites. In performing this evaluation, special consideration should be given to installing tree wire where it will protect against outages on lines that supply power to critical services such as public service radio transmission and repeater equipment, cellular telephone towers, and water supply, medical, and first responder facilities.

5. STORM HARDENING – TRANSMISSION INTERFACES

Q. ARE THERE OTHER AREA SUPPLY ISSUES THAT SHOULD BE INCLUDED IN A COMPREHENSIVE STORM HARDENING PROGRAM?

A. Yes.

Q. PLEASE EXPLAIN.

A. Regional experiences with Hurricane Sandy highlighted the need to harden transmission system tie lines and their related remote-end connections from other utilities or control areas. Such tie lines enable the exchange of economic energy under normal operations and provide a means of emergency assistance should other resources on the LIPA system become unavailable. These ties are especially critical to the LIPA system given the geography of Long Island and its relatively isolated power system, and the interfaces can supply a significant portion of LIPA's load. In a storm situation, local generation can become unavailable due to damage or isolation from the grid due to line or substation outages. As resources available to serve remaining load become fewer and fewer, tie lines to other areas can provide needed optionality to a system operator in emergency conditions where unusual system configurations can occur. If a storm event is somewhat localized, these external ties can offer support from a remote power system that may have been minimally impacted by the storm. Because optionality is critical when operating a power system under unusual conditions, tie lines to external areas should be part of a storm hardening program's evaluation to insure that they can be available if needed. This point was acknowledged in the "Storm Hardening Talking Points" presented at the January 2012 Trustees meeting and attached to City-90. The Talking Points state that "[i]mproved interconnections result in additional flexibility" that increases "the durability and resilience of the system."

Con Edison's experience during Hurricane Sandy illustrates this concern. Con Edison has several phase angle regulator controlled ties to the PSE&G system in New Jersey, including two submarine cables that connect to the PSE&G Hudson substation from Con Edison's Farragut substation in Brooklyn. These cables were not directly impacted by Hurricane Sandy's storm surge because they are underground and submarine. The storm, however, inundated the Hudson substation and rendered these ties unusable for emergency support. As other generating resources on the Con Edison system became unavailable due to storm damage, and as other tie lines became unavailable for importing power into the area to serve remaining load, it became more difficult for system operators to retain system reliability with remaining resources.

Q. WHY IS THIS EXAMPLE RELEVANT FOR THE LIPA/PSEG-LI STORM HARDENING PLAN?

A. The LIPA system is connected to adjacent utilities and control territories via numerous ties. This includes the Neptune Regional Transmission System, which was knocked offline at its remote end in New Jersey during Hurricane Sandy. LIPA also is connected to other systems via the Cross Sound Cable, the Northport-Norwalk cable, and the 345 kV cables to the Sprain Brook and Dunwoodie substations owned by Con Edison in Westchester County. Of these facilities, Neptune, Cross Sound Cable, and the Northport-Norwalk cable terminate in substation facilities located very close to bodies of water subject to storm surge flooding. LIPA also is connected to the Con Edison system via two phase angle regulator-controlled tie points at the Valley Stream and Lake Success substations.

Impairment of these interfaces may not have been a substantial factor in the LIPA service outages caused by Hurricane Sandy, but they are vulnerable points on the system that also need to be hardened against future climate events. PSEG-LI's storm hardening program should address the assets that LIPA owns on its side of the transmission interfaces. The Trustees and PSEG-LI also should discuss with the owners of the assets on the other side of those interfaces the need to improve the resiliency of same. This matter also should be examined by the collaborative.

6. STORM HARDENING – NATURAL GAS SUPPLY

Q. ARE THERE OTHER SYSTEMS WHICH SUPPORT OPERATION OF THE ELECTRIC TRANSMISSION SYSTEM WHICH SHOULD BE INCLUDED IN A STORM HARDENING ASSESSMENT?

A. Yes. Many generating plants on Long Island are fueled by natural gas and rely on supplies from the regional gas transmission system. An outage or curtailment of natural gas supplies on these pipelines could have an adverse impact on electric system reliability. Even though some plants have the capability to burn oil as an alternate fuel Hurricane Sandy demonstrated that the fuel oil supply chain can be interrupted for extended periods of time. This increases the importance of maintaining a reliable natural gas supply, and the utility's ability to sustain the fuel oil supply chain during and following a storm event should be considered as part of overall storm hardening evaluations.

Q. WHAT KINDS OF NATURAL GAS FACILITIES SHOULD BE CONSIDERED FOR STORM HARDENING?

A. Any pipeline-related facility that could be subject to storm surge flooding should be evaluated and protected from that potential flooding. This may include compressor stations which are critical to maintaining sufficient pressures for operation of natural gas fueled plants.

Q. ARE THESE FACILITIES TYPICALLY UNDER LIPA'S CONTROL?

A. No, they are typically owned and operated by pipeline companies. However, given that pipeline outages might adversely impact the electric system, close coordination between these pipelines and electric system operations have been recognized as critical to electric system security, and efforts are underway by entities such as NYISO to better coordinate operations. This coordination should be extended to storm hardening evaluations so that natural gas facilities that are critical to the electric system are identified. If those facilities are vulnerable to storm damage, they should be hardened to withstand those events.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Before the
New York State Public Service Commission

In the Matter of

Long Island Power Authority and

Service Provider, PSEG-LI Long Island LLC

Matter No. 15-00262

May 2015

Prepared Direct Testimony of:

Radley Horton, Ph.D.

On Behalf of:

The City of New York

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Radley Horton. I am an Associate Research Scientist employed by the Center for Climate Systems Research ("Climate Research Center") at Columbia University.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony before the New York State Public Service Commission ("PSC") on behalf of the City of New York ("City"). I am appearing in this proceeding as an independent consultant to the City, and not in my capacity as an Associate Research Scientist for the Climate Research Center.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Ph.D. and an M.S. from Columbia University in Earth and Environmental Sciences. I have contributed in various capacities to leading studies on climate change, and authored or co-authored numerous articles on climate change projections and impact assessments. I also have authored articles addressing the implications for climate change adaptation and planning efforts, including articles on coastal adaptation for infrastructure, sea level rise projection methods, climate hazard assessments in New York City and Long Island, and resilient adaptation planning. My professional background is presented in detail in my Curriculum Vitae, which is attached as Exhibit__[RH-1].

Q. PLEASE SUMMARIZE YOUR EXPERIENCE IN THE AREA OF PROJECTING CLIMATE CHANGE.

A. In 2008, New York City convened the New York City Panel on Climate Change ("NPCC"). I was the Climate Science Lead for two iterations of the NPCC Technical

Working Group. Our work included the production of multiple reports that provided climate projections for New York City and identified some of the potential risks to infrastructure posed by climate change.

In 2011, New York State issued ClimAID, a statewide Climate Impact Assessment. In 2014, the climate projections were updated to reflect results from a new generation of global climate models, as well as recent observed data. The ClimAID report divided New York State into seven regions, one of which covered New York City and Long Island, and assessed climate impacts in eight sectors, including energy. I led the development of climate projections for the 2011 ClimAID and the 2014 ClimAID update.

I also am one of two Convening Lead Authors for the Northeast Chapter of the third National Climate Assessment ("NCA"), which was released in May 2014. The NCA is a status report about climate change science and impacts that is delivered to the President of the United States, Congress, and the public approximately every four years. The NCA integrates information from across a variety of federal climate research initiatives to present a comprehensive picture of the effects of global climate change on many sectors of society. It also analyzes trends in global climate change and predicts future changes over a one hundred year period.

Q. HAVE YOU EVER DONE CLIMATE ANALYSIS FOR A UTILITY?

A. Through my university position, I am the Principal Investigator on a Columbia University project with Consolidated Edison Company of New York, Inc. ("Con Edison"). The project includes analysis of historical climate data and development of climate projections.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PSC?

A. Yes. I provided written testimony and was made available for oral testimony at public hearings in Cases 13-E-0030, 13-G-0031, 13-S-0032, 14-E-0318, 14-G-0139, 14-E-0493, and 14-G-0494.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Climate change poses a variety of hazards to utility infrastructure, including assets located in the service territory of the Long Island Power Authority ("LIPA"). As the twenty-first century progresses, extreme heat events are projected to become more frequent and intense, and sea level rise is projected to cause increased coastal flooding. It also is likely that intense precipitation events will become more frequent. In light of these projected changes, utility infrastructure is likely to be faced with a different range of environmental conditions than it has experienced in the past. Utility investments in new and existing infrastructure should anticipate and address these changes by reflecting design standards that are based on the best-available data regarding future climate change.

My testimony (i) discusses the current climate projections for Long Island, (ii) evaluates the climate projections that LIPA and PSEG-LI Long Island LLC ("PSEG-LI-LI") have relied on when designing storm hardening projects, and (iii) recommends changes in the climate data that LIPA and PSEG-LI are relying on. The climate projections discussed in my testimony complement the discussion of how climate projections should be reflected in storm hardening and resiliency projects that is presented by City witness John Marczewski.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I offer five exhibits, as follows:

- Exhibit__[RH-1] – Curriculum Vitae;
- Exhibit__[RH-2] – Excerpt from ClimAID 2011;
- Exhibit__[RH-3] – Excerpt from ClimAID 2014;
- Exhibit__[RH-4] – Excerpt from 2015 NPCC Report;
- Exhibit__[RH-5] – Compilation of PSEG-LI/LIPA responses to City discovery requests.

MODELING CLIMATE CHANGE

A. THE SCIENTIFIC FOUNDATION OF CLIMATE PROJECTIONS

Q. WHAT ARE GLOBAL CLIMATE MODELS?

A. Global climate models are mathematical representations of the physical processes that govern the Earth's climate. They are comprised of hundreds to thousands of pages of computer code that are compiled by supercomputers for a variety of applications. Climate models are the best tools available for projecting the future state of the climate, and they have been embraced by a number of scientific bodies including the Intergovernmental Panel on Climate Change (IPCC). (The IPCC is the leading international scientific body charged with assessing climate change science, impacts, and potential solutions.) Computer models are standard research tools that are used in a variety of contexts to understand and predict the dynamics of complex systems, including regional or global climate. Model projections of future climate have improved over time as scientific understanding and computing power have advanced.

Q. CAN YOU TEST THE RELIABILITY OF MODEL OUTPUTS?

a. Yes. Climate models have been validated, or back-tested, using climates of the past. Models are back-tested by inputting prior conditions such as historic greenhouse gas concentrations, changes in incoming solar radiation, or the impact of volcanic eruptions. Model outputs are then evaluated to determine whether the predicted results match the observed conditions. It has been demonstrated in this manner that climate models are able to reproduce the general climate responses that actually occurred. These responses go far beyond surface air temperature, and include everything from temperature gradients in the upper atmosphere to the seasonal progression of monsoons. By looking at all of these outputs, we can develop a variety of theories. The modeling results point to a dominant influence of greenhouse gas increases on the climate, and indicate that the climate projections produced by the models are useful.

Q. **ARE CLIMATE MODELS OUR ONLY TOOLS FOR PROJECTING FUTURE CLIMATE?**

A. No. Some physical processes – such as melting at the edge of an ice sheet and other events that occur at fine spatial scales– exceed the capability of even the most powerful climate models. In those instances, we rely primarily on observed data and expert knowledge as a basis for climate projections. In general it is the combination of climate model results, observed data, and expert knowledge based on physical understanding that yield climate risk-based approaches to decision-making.

Q. WHAT DO YOU MEAN BY CLIMATE RISK-BASED APPROACHES FOR DECISION-MAKING?

A. Risk-based approaches present a range of possible outcomes to inform decision-making. They are based on the principle that although the future is uncertain, there is enough information available to inform decision-making, especially relative to the alternate approach of assuming that what was experienced in the past will continue without change. Several scientific and professional bodies including the National Research Council ("NRC") have embraced risk-based approaches of the type described below that were developed for Long Island. The future climate cannot be known with precision for a variety of reasons including uncertainty about exactly how much greenhouse gases society will emit and exactly how sensitive the climate system will be to those emissions. However, climate science has advanced to the point where we can say with high confidence that decisions involving important and expensive long-lived assets, such as PSEG-LI's storm-hardening program, should reflect a range of possible future climate outcomes and not rely solely on the static historical climate data.

Q. DO THE MODELS PROVIDE CLIMATE PROJECTIONS SPECIFIC TO LONG ISLAND?

A. Models make climate projections in gridboxes with a spatial resolution of roughly 150 miles by 100 miles. A single gridbox will often cover both New York City and Long Island. In general, neighboring gridboxes over land show very similar projections.

Q. ARE CLIMATE PROJECTIONS FOR A REGION THAT INCLUDES LONG ISLAND AND NEW YORK CITY RELEVANT TO THE LIPA SERVICE TERRITORY?

A. Yes. In general, the described changes projected for the New York City and Long Island region pertain to time-average conditions such as temperature, precipitation and sea level that are applicable throughout the entire New York City and western Long Island region, which I will refer to here simply as the "Region." Because both the NPCC projections and the ClimAID update cover the Region and feature nearly identical projections for most variables, I will refer to them collectively as the "Climate Reports." To the extent that my testimony addresses changes that vary significantly over spatial scales that are larger or smaller than the Region, the distinction is noted and I specify the relevant spatial location and climate report I am referring to.

Q. DID THE NPCC AND CLIMAID REPORTS CONCLUDE THAT CLIMATE IS CHANGING IN NEW YORK STATE?

A. Yes. Both the NPCC and ClimAID reports concluded that the climate is changing in New York State. I agree with those conclusions.

Q. IN LIGHT OF THE PROJECTED CHANGES IN CLIMATE THAT WILL IMPACT LONG ISLAND, IS UTILITY INFRASTRUCTURE LIKELY TO BE FACED WITH A DIFFERENT RANGE OF ENVIRONMENTAL CONDITIONS THAN IT HAS EXPERIENCED IN THE PAST?

A. Yes. By the time we reach the 2020s, and to an even greater extent as we move into the second half of the century, the climate will be statistically different than it has been in the past. There will continue to be natural variability, such that some years will display climate very similar to that seen in the past thirty years. However, there is also likely to be variability in the other direction such that we will increasingly experience unprecedented high temperatures, more extreme coastal and inland flooding, and shifts in average climate conditions. Infrastructure that we build today and will be operating for decades will have to function in these changed (and changing) conditions. This requires that electric system planning consider, and prepare for, the possible range of future environments.

B. AMBIENT TEMPERATURE INCREASE

Q. HAVE YOU STUDIED THE POTENTIAL FOR AMBIENT TEMPERATURES IN THE REGION TO INCREASE DUE TO CLIMATE CHANGE?

A. Yes. In 2010, the NPCC presented climate projections (including temperature increases) for the Region, examined how climate change and increased temperature would impact critical infrastructure, and proposed strategies for adapting to projected climate changes. In 2010, the NPCC Report published the projected increases in temperature for the Region. In 2011, we published a report called "Response to Climate Change in New York State," also known as ClimAID, in which we prepared temperature projections for all of New York State. Excerpts from the ClimAID 2011 Report and the NPCC Report, which was updated in 2014, are provided as Exhibit__[RH-2] and Exhibit__[RH-4], respectively. In 2014, the ClimAID projections also were updated. The 2014 ClimAID update is provided as Exhibit__[RH-3].

Q. BASED ON THE UPDATED NPCC AND CLIMAID STUDIES, WHAT IS THE PROJECTED INCREASE IN TEMPERATURE FOR LONG ISLAND FOR THE REST OF THIS CENTURY?

A. Using the average annual temperature from 1971-2000 as a baseline, temperature increases in the Region are projected to range from 1.5° to 3.2°F by the 2020s, 3.1° to 6.6°F by the 2050s, and 3.8° to 10.3°F by the 2080s. A substantial temperature increase is projected to occur even under a low emissions scenario.

In Long Island, the NPCC and ClimAID reports observed past trends and then modeled future temperature rise. For example, temperature increased by an average of about 0.3°F per decade since 1900. The projected future temperature changes indicate that by the 2080s, western Long Island's mean temperature throughout a "typical" year may bear similarities to a city like Raleigh, North Carolina, or Norfolk, Virginia, today. Because variability is larger in winter than in summer, the summer changes may produce relatively larger deviations than the winter changes — at both daily and seasonal scales — as compared to what has been experienced historically during individual years. Put another way, the climate change 'signal' in summer is projected to emerge relatively quickly from the background 'noise' of climate variability, since the 'noise' is less pronounced in the summer than it is in the winter. This is true both for individual days and for seasons.

Q. THE MODELS PROJECT A RANGE OF TEMPERATURE INCREASES. HOW DO YOU USE A RANGE OF POSSIBLE OUTCOMES TO DETERMINE THE TEMPERATURE INCREASE THAT SHOULD BE SELECTED AS A DESIGN STANDARD FOR STORM HARDENING AND RESILIENCY PROJECTS?

A. This is a risk management question, so my area of expertise, climate science, can only provide a partial answer. Design standards are based on the probability of a particular climate outcome as well as the consequences associated with that outcome. Climate science tells us that the probabilities of occurrence of many climate hazards (or outcomes) including heat events, coastal flooding, and intense precipitation are projected to increase. The potential impacts on utility infrastructure associated with those risks also would be expected to increase, unless design standards are modified to mitigate those increasing risks. For assets that are critical and/or have a longer useful life, it may be prudent to adopt a more stringent standard. Mr. Marczewski addresses how to deal with projected climate change in his testimony.

Q. BASED ON YOUR RESEARCH AND EXPERIENCE, IS LONG ISLAND MORE LIKELY TO EXPERIENCE EXTREME HEAT EVENTS IN THE FUTURE?

A. Yes. Long Island is projected to experience more individual days of extreme heat, as well as an increase in the frequency and duration of heat waves, which are defined as three consecutive days with maximum temperatures at or above 90°F.

Between 1971 and 2000, New York City's Central Park saw an average of 18 days per year with temperatures at or above 90°F, 0.4 days per year at or over 100°F, and two heat waves per year. The 2014 ClimAID report projected that the number of days at or above 90°F is projected to increase to 24 to 33 days by the 2020s, 32 to 57 days by the 2050s, and 38 to 87 days by the 2080s. The number of heat waves also is projected to jump from two per year (as observed during the 1971-2000 period) to 5 to 9 per year by the 2080s. Although the baseline number of days at or above 90°F differs throughout the Region due to factors including coastal breezes, the general pattern of a large percentage increase over time in the number of days at or above 90°F is projected to apply for the entire Region.

Q. HAVE OTHER STUDIES ALSO PREDICTED INCREASED TEMPERATURE FOR THE REGION?

A. Yes. Other studies including, but not limited to, the 2014 NCA projects future ambient temperatures for the Northeastern U.S. including Long Island that are comparable to the changes projected by CliMAID 2014. Further, the 2014 NCA reports that annual average temperature in the Northeast Region (which includes Long Island) already has increased by approximately 2°F since 1900.

Q. DOES PSEG-LI CONSIDER PROJECTED TEMPERATURE INCREASES WHEN DESIGNING STORM HARDENING PROJECTS?

A. As detailed later in my testimony, the PSEG-LI Capital Budget Panel explained that the company relies on a temperature/humidity metric for certain storm hardening projects. The metric, however, relies on climate data from a historic thirty-year period without any reference to climate projections.

Q. GIVEN THE PROJECTED TEMPERATURE INCREASES, DOES IT MAKE SENSE TO BASE A RISK MANAGEMENT PLAN FOR TEMPERATURE ON A THIRTY-YEAR AVERAGE OF HISTORIC TEMPERATURE DATA?

A. From my perspective as a climate scientist, no. By the time we reach the 2020s, we would expect higher temperatures and more frequent heat events than were observed in the past thirty-year period. There will still be years with fewer hot days than average, as natural variability in the climate will continue. However, from a risk management perspective, the projections will have shifted sufficiently that it would be unwise to use the past 30 years as a precedent and basis for future conditions. The climate ‘dice’ are effectively being ‘loaded’ gradually towards favoring higher temperatures at the expense of lower ones.

C. SEA LEVEL RISE AND COASTAL FLOODING

Q. HAVE YOU STUDIED THE RATE OF SEA LEVEL RISE IN THE COASTAL NEW YORK REGION?

A. Yes. I have been involved in several studies that examined the rate of sea level rise in the coastal New York region. Our findings have been included in various papers, including the 2011 and 2014 ClimAID studies for coastal New York State including Long Island,

and the NPCC Report for the New York City metro area. Because the rates of sea level rise are projected to be virtually identical for New York City and Long Island, the results for the two studies can be used interchangeably.

Q. BASED ON YOUR RESEARCH AND EXPERIENCE, WHAT IS THE PROJECTED SEA LEVEL RISE IN THE COASTAL NEW YORK REGION BETWEEN 2013 AND 2100?

A. In developing the 2014 ClimAID report, we projected sea level rise in the Long Island coastal region of 2 to 10 inches by the 2020s, 8 to 30 inches by the 2050s, and 13 to 58 inches by the 2080s. Other studies project that a worst-case scenario could result in a sea level rise of up to six feet by 2100. This is an approximate upper bound, but it is a potential outcome and hence may be a relevant consideration for the location, design and construction of the most critical, long–lived utility assets that may be impacted by flooding associated with this change in sea level.

Other recent studies examining sea level rise in the Northeast region looked at sea level rise as it will increase over time as well as the relative rate of increase in the Northeast as compared to other regions. The results of those studies are consistent with what I described above.

Q. HOW WILL SEA LEVEL RISE IMPACT FUTURE FLOOD EVENTS?

A. Higher sea levels increase the frequency and intensity of coastal flooding (including the area that is inundated and the depth of the floodwater) during coastal storms. Higher sea levels also can increase rainfall-induced flooding by making it more difficult for rainwater in low-lying areas and estuaries to drain into the sea.

Q. ARE THERE ANY STUDIES ON THE EFFECTS OF SEA LEVEL RISE ON COASTAL FLOODING IN THE LONG ISLAND REGION?

A. The 2010 NPCC Report and 2014 update and 2011 and 2014 ClimAID reports discuss the effects of sea level rise on coastal flooding in the Region. According to the ClimAID 2011 report, "[s]ea level rise will lead to more frequent and extensive coastal flooding. Warming ocean waters raise sea levels through thermal expansion and have the potential to strengthen the most powerful storms.…Sea level rise in combination with a coastal storm that currently occurs about once every 100 years on average is expected to place a growing population and more property at risk from flood and storm damage."

Q. WHAT IS A 1-IN-100 YEAR FLOOD?

A. A 1-in-100 year flood is a flood height that has a one percent chance of being exceeded in a year. Most definitions of the 1-in-100 year flood have historically not considered how sea level rise or changes in storms over time could modify this hazard; rather, they have treated the hazard probability as constant through time.

Q. WHY IS THE 1-IN-100 YEAR FLOOD RELEVANT TO DESIGNING UTILITY INFRASTRUCTURE PROJECTS THAT ARE LESS VULNERABLE TO CLIMATE CHANGES?

A. The 1-in-100 year flood is used for a variety of planning and regulatory applications. For example, it is a frequently used metric for zoning and insurance. If the historically defined height thresholds for the 1-in-100 year elevation continue to be used without modifications that reflect sea level rise projections, however, then the ability of those standards to protect against severe flood events will be reduced, potentially significantly, as the sea level rises.

Q. WILL CLIMATE CHANGE IMPACT THE FUTURE FREQUENCY OF 1-IN-100 YEAR FLOODS?

A. The NPCC projects that the current likelihood of a hundred-year coastal flood will increase. By the 2020s, the probability of these events is projected to increase from the current probability of 1.0% per year, to 1.1% to 1.7% per year. By the 2050s, this probability is projected to increase to between 1.4% to 5.0%. By the 2080s, the probability of a hundred-year flood occurring in any given year is projected to increase to 2.0% to 18.5%. Importantly, these projections are based solely on average sea level rise, without consideration of how storms themselves may change.

Q. WHAT IS A 1-IN-500 YEAR FLOOD?

A. A 1-in-500 year flood is a flood height that has a 0.2 percent chance of being exceeded in a year. Most definitions of the 1-in-500 year flood have historically not considered how sea level rise or changes in storms over time could modify this hazard; rather, they have treated the hazard probability as constant through time.

Q. DO THE 2013 FEMA FLOOD MAPS FOR NEW YORK STATE INCORPORATE FUTURE PROJECTIONS OF SEA LEVEL?

A. No. Consequently, although LIPA and PSEG-LI should be using the most current flood maps as a design reference for relevant projects, those maps reflect only current exposure to coastal flooding. An additional safety margin would have to be reflected in a project design to account for changes in sea level rise that are projected to occur during the asset’s useful life. It should also be noted that the 2013 flood map updates are based on an updated set of historical storms and models as compared to the earlier FEMA maps. It is important that design standards be adopted with an understanding that the rising sea level may increase the frequency with which a particular flood – such as the 1-in-100 year or 1-in 500 year flood – occurs, even if current flood maps do not reflect such changes in future climate conditions.

D. EXTREME WEATHER EVENTS

Q. HAS THE CONNECTION BETWEEN CLIMATE CHANGE AND SEVERE WEATHER EVENTS BEEN STUDIED?

A. Numerous studies have explored the connection between climate change and severe weather events, most notably in the Intergovernmental Panel on Climate Change ("IPCC") Special Report on Extreme Events. The Special Report concluded that "[a] changing climate leads to changes in the frequency, intensity, spatial extent, duration, and timing of extreme weather and climate events, and can result in unprecedented extreme weather and climate events." The 2011 ClimAID and 2010 NPCC reports also discuss this connection.

Q. HAVE YOU STUDIED THE EFFECT OF CLIMATE CHANGE ON EXTREME WEATHER EVENTS SUCH AS HURRICANES, HEAVY PRECIPITATION EVENTS, SNOWSTORMS, AND FLOODS?

A. Yes. These effects are discussed in the ClimAID (for New York State) and NPCC (for New York City) reports.

Q. WHAT IS THE PROJECTED EFFECT OF CLIMATE CHANGE ON EXTREME WEATHER EVENTS?

A. Climate change is projected to result in an increase in the frequency, intensity and duration of heat waves, as discussed above. Since warmer air holds more moisture, precipitation tends to be concentrated in more extreme events. Thus, the frequency and severity of heavy precipitation and flooding events is projected to increase. The frequency of the most intense hurricanes in the North Atlantic Ocean will more likely than not increase as well. As the century progresses, snowfall frequency and total amount are likely to decrease as more precipitation will fall in the form of rain. However, if the air is cold enough, the snowstorms that do occur could be more intense. It is unclear how the frequency and intensity of ice storms may change in the future, but it is important to note that they pose significant hazards in the current climate.

Q. SHOULD UTILITY INFRASTRUCTURE BE DESIGNED OR MODIFIED TO WITHSTAND HEAT WAVES?

A. I previously explained the reasonable expectation that LIPA's service territory will experience heat waves of greater frequency, intensity and duration. All things being equal, electric system assets that are vulnerable to heat waves and increased ambient temperatures would need to be modified to withstand those more frequent, intense and longer duration events.

Q. SHOULD UTILITY INFRASTRUCTURE BE DESIGNED OR MODIFIED TO WITHSTAND FUTURE ICING EVENTS?

A. My understanding is that electric systems currently are vulnerable to outages caused by ice loading. For this reason alone, it makes sense to design or modify those systems to continue operating under icing conditions. Although it is difficult to model future icing events with certainty, they will continue to occur under future climate conditions. Therefore, utility infrastructure should be designed or modified to withstand future icing events.

Q. HOW WILL CLIMATE CHANGE IMPACT THE FREQUENCY AND INTENSITY OF FUTURE TROPICAL WEATHER EVENTS?

A. As mentioned earlier, the balance of evidence suggests that it is more likely than not that the strongest hurricanes in the North Atlantic may become more frequent. We can project with high confidence that sea level rise will increase coastal flooding whenever tropical storms interact with land. This means that coastal flooding will be more frequent and more severe in the future, even if the relative intensity of future storms does not change. That is, if two storms of equal intensity were to impact Long Island today and in 2040, the future storm would induce greater coastal flooding as compared to the 2015 storm due solely to increased sea level.

Q. WAS THIS PHENOMENON A FACTOR IN HURRICANE SANDY?

A. Yes. It has been estimated that, if Hurricane Sandy had struck a century earlier when sea level in the Region was about one foot lower, flooding would have impacted seventy square kilometers less land, and 80,000 fewer people in New York and New Jersey.

Q. WHAT OTHER EFFECTS WILL CLIMATE CHANGE HAVE ON TROPICAL STORMS?

A. There is compelling evidence that precipitation in the strongest tropical storms may become more intense. The coincident impacts of sea level rise and precipitation of greater intensity in a coastal storm could result in flooding that is more severe than otherwise would be expected from the operation of either factor alone.

Q. BASED ON YOUR FAMILIARITY WITH CURRENT CLIMATE PROJECTIONS, IS HURRICANE SANDY AN APPROPRIATE BENCHMARK

FOR UTILITIES TO RELY ON AS A BASIS FOR STORM HARDENING DESIGN STANDARDS?

A. Hurricane Sandy was a unique storm. Although its wind speeds at landfall were consistent with a weak Category 1 hurricane, its storm surge – which is very location dependent – was consistent with a Category 3 hurricane. Category 3 hurricanes impact Long Island relatively infrequently; the last such storm may have been the Great Hurricane of 1938. Climate models currently do not have the resolution needed to estimate the probability that a hurricane of Category 4 or higher will strike Long Island, although the risk is thought to be low even in a warming climate. For now, therefore, it is reasonable for utilities to design infrastructure to withstand the impacts of a Category 3 hurricane, subject to one significant caveat.

Q. WHAT IS THE CAVEAT?

A. As I noted earlier, climate change will increase the severity of coastal flooding even if there is no change in storm intensity over time. For this reason, it is not adequate simply to design utility infrastructure to withstand another Hurricane Sandy. Infrastructure should be designed to withstand the impacts of future, not historic, weather events.

It also would be inadequate to focus exclusively on assets and locations that were damaged by Hurricane Sandy. Those impacts were the specific result of the storm's trajectory and other factors. Certain areas impacted by Hurricane Sandy were not at high tide, or may not have experienced the most severe flooding possible for the area based on storm trajectory and other factors. That is, the distribution of infrastructure damage during Hurricane Sandy depended on the confluence of many variables, and it could have been very different if key variables – including storm trajectory – had been different.

While Sandy's storm surge was extreme, storms with stronger winds and more precipitation can be expected to impact the Region in the future, and they may have comparable (or worse) storm surges. Alternate sequences of weather are also possible. For example, had a tropical cyclone of Hurricane Sandy's approximate strength struck two months earlier, which is within the time period that tropical cyclone strikes in the region are most likely to occur, the Region would have been more likely to contend with a heat wave, rather than a Nor'easter, during the week following the storm.

Q. WHAT DO YOU RECOMMEND?

A. From the perspective of a climate scientist, it makes sense for storm hardening projects to be done on a system-wide basis and reflect a safety margin that is designed to account for the cumulative impacts of sea level rise and coastal storm flood risks, including from a Category 3 hurricane, as reflected in the 2013 FEMA map updates. These safety margins should be based on the best available climate projections, flood maps, and other current data – including LIDAR – and should be reviewed and updated regularly.

Q. ARE THERE ANY STUDIES THAT PROVIDE ESTIMATES OF FUTURE WIND EVENTS?

A. There is comparatively less confidence in projections of extreme winds, in part because of the relative infrequency of extreme wind events. The computer simulation of these events is being refined, but the modeling results are not yet as reliable as for other aspects of climate change. However, the NPCC determined that there is some basis to conclude that the strongest hurricanes could become more frequent and intense in the North Atlantic Ocean basin, and therefore the strongest wind events in the North Atlantic Ocean basin may also increase.

Q. CAN YOU RECOMMEND SPECIFIC SAFETY MARGINS THAT LIPA AND PSEG-LI SHOULD ADOPT AS A BASIS FOR STORM HARDENING PROJECTS?

A. Specific safety margins are a project engineering matter that is outside my area of expertise and the scope of this testimony. However, LIPA and PSEG-LI should adopt my recommendations, and rely on the climate-based information identified in my testimony, when considering the specific safety margins that are appropriate for their infrastructure investments. For example, the sea level rise projection ranges described in my testimony can inform LIPA/PSEG-LI decision-making about appropriate safety margins and risk management. For longer-lived and/or critical assets, it may be prudent for the utility to base design standards on the higher part of the projection estimates as a conservative planning measure.

Q. ARE THERE SPECIFIC RESOURCES THAT YOU WOULD RECOMMEND LIPA AND PSEG-LI CONSULT WHEN DESIGNING STORM HARDENING PROJECTS?

A. For global and national context, the IPCC Assessment Reports, including the 2012 Special Report of Emissions Scenarios, and the USGCRP Third National Climate Assessment are recommended. For state and local information, the ClimAID Reports and the NPCC Reports provide more detailed predictions.

LIPA/PSEG-LI CLIMATE ASSUMPTIONS AND METRICS

Q. DOES PSEG-LI RELY ON ANY CLIMATE-RELATED METRICS TO INFORM DECISIONS REGARDING STORM HARDENING PROJECTS?

A. Yes. PSEG-LI indicated in response to City-60 that it uses "several" such metrics, including temperature/humidity.

Q. HOW IS THAT METRIC DEVELOPED?

A. The temperature/humidity metric is developed via a weather normalization process that relies on thirty years of historic climate data. The weather normalization process includes the development of a regression model that considers actual weather conditions from up to 360 data points observed during the June through September period for up to three prior summer periods.

Q. PLEASE CONTINUE.

A. PSEG-LI explained that the regression model will include data points from a single summer if the weather during that period was "sufficiently hot." The company explained in response to City-86 that the phrase "sufficiently hot weather" means that the data used for the regression model "should include at least one day when the actual peak load occurred at a temperature that reached the normal level of 90.3 degrees Fahrenheit for the peak hour. Ideally, the model will include several days when the experienced weather conditions exceeded normal. If needed, data from previous summers may be included to produce a distribution that is judged to be valid." Importantly, PSEG-LI did not specify the minimum number of data points from "sufficiently hot weather" that it considers necessary "to develop a valid regression model."

Q. WHY IS THE NUMBER OF DATA POINTS AN IMPORTANT CONSIDERATION?

A. The model must consider a minimum number of data points to provide an output that is statistically significant. If an insufficient number of data points are used, then the model output is not statistically significant, and the results are unreliable. The minimum number of data points needed for statistical analysis can be derived. PSEG-LI does not specify the minimum number that it requires for the weather normalization process, or how the weather normalization process is impacted if an insufficient number of data points is utilized. Regardless, however, this issue is secondary to my primary concern with this metric.

Q. WHAT IS YOUR PRIMARY CONCERN REGARDING THE TEMPERATURE/HUMIDITY METRIC THAT PSEG-LI USES?

A. PSEG-LI confirmed in City-60 that the metric is used to inform capital investment decisions, including storm hardening projects. Regardless of whether the regression model considers one, two or three prior summer periods or the number of data points included therein, the temperature/humidity metric used by PSEG-LI relies entirely on historic data. Storm hardening projects should be designed to withstand future climate conditions, which are not reflected in the temperature/humidity metric.

Q. PLEASE CONTINUE.

A. Designing utility systems to meet the demands of the historic climate could leave the system vulnerable to the demands of a future climate that is projected to be characterized by higher average ambient temperatures and heat waves of greater frequency, duration and intensity. The most recent summer periods are not necessarily representative of future climate—or historic climate, for that matter. Further, the small sample size of up to three summer periods is inadequate to support a reliable projection of future weather, even if the regression model used those recent summer periods to project future conditions (which it does not do).

Q. WHAT DO YOU RECOMMEND?

A. Assets that may be vulnerable to temperature-related failure should be designed to operate under future climate conditions. At a minimum, the design standards employed by PSEG-LI should be revised to account for increased average ambient temperatures and heat waves of greater frequency, duration and intensity.

Q. ARE YOU RECOMMENDING SPECIFIC DESIGN STANDARDS FOR THIS PURPOSE?

A. No, that is beyond the scope of my expertise and this testimony. I understand, however, that City witness John Marczewski is recommending that LIPA convene a storm hardening collaborative. I agree with that recommendation, and also recommend that details such as climate projections and design standards be key elements of the collaborative.

Mr. Marczewski also recommends that LIPA and PSEG-LI undertake a climate vulnerability study as part of the collaborative. I agree with this recommendation as well. The climate vulnerability study will provide a long-range basis for the ongoing review of climate change projections. This data will be important for the design of future storm hardening projects.

Q. DID PSEG-LI CONSIDER SEA LEVEL RISE WHEN DESIGNING STORM HARDENING PROJECTS?

A. Yes. PSEG-LI indicated in various responses to City information requests that relevant storm hardening projects – such as projects to elevate substation equipment – relied exclusively on analyses of asset vulnerability to projected sea level rise and coastal flooding that was prepared by Worley Parsons. The redacted Worley Parsons reports were provided in response to City-33 and City-36.

Q. WHAT WAS THE SOURCE OF THE CLIMATE PROJECTIONS THAT WORLEY PARSONS RELIED ON?

A. The Worley Parsons report relied on our original ClimAID study of 2011. While that report included two sea level rise scenarios, the Worley Parsons report only considered the lower of the two scenarios, without providing an explanation or justification for this decision. As I noted earlier, the 2011 ClimAID study was later updated to reflect scientific advances including greater awareness of the risk of rapid sea level rise due to rapid melting of land ice. Our updated ClimAID report in 2014 reflected this advance by integrating the rapid ice melt scenario into a unified single sea level rise framework/scenario. The 2014 update also included additional sea level rise components that we had excluded from the original work.

Worley Parsons' analysis also included what appears to be a short duration sea level trend analysis projection. Short duration trends can be highly sensitive to natural variability and, therefore, tend to be less reliable. Furthermore, because the rate of sea level rise is projected to accelerate, the use of a historical linear trend is not appropriate for future extrapolations/projections. I was unable to discern from the Worley Parsons reports the justification for including the short duration trends in their projection.

Q. WHAT CONCLUSIONS REGARDING SEA LEVEL RISE ARE PRESENTED IN THE WORLEY PARSONS REPORTS?

A. The Worley Parsons reports predict an average sea level rise of 15 inches by 2125, and they provide no range or uncertainty estimates. This projection is at or below the lowest projections currently in use anywhere, to my knowledge. For example, the Climate Reports project 13 to 58 inches of sea level rise for the Region by the 2080's. Thus, the single value assumed by Worley Parsons is less than the lower bound of the New York City and New York State sea level rise projections.

Q. WHAT SEA LEVEL RISE DID WORLEY PARSONS RECOMMEND BE ASSUMED FOR SYSTEM PLANNING PURPOSES?

A. Worley Parsons noted that typical substation equipment has a 40-year lifespan, and recommended that a sea level rise of eight inches be assumed for planning purposes. Put differently, Worley Parsons effectively assumed that Long Island will realize eight inches of sea level rise by the mid-2050's.

Q. HOW DOES THIS ASSUMPTION COMPARE TO CURRENT PROJECTIONS OF SEA LEVEL RISE?

A. Current projections indicate that Long Island may experience sea level rise of eight to thirty inches by the 2050s. Recent data further indicate that the rate and/or magnitude of sea level rise may be increased by the accelerated melting of glacial ice. Based on current projections and my understanding of emerging factors that may impact those projections, I would not recommend that a design standard for important and valuable assets be based on the lowest projection of sea level rise.

Q. IN YOUR OPINION, DO THE WORLEY PARSONS REPORTS RELY ON CURRENT OR APPROPRIATE CLIMATE CHANGE PROJECTIONS?

A. No.

Q. PLEASE EXPLAIN.

A. The methods in the Worley Parsons reports do not reflect the current state of climate science for at least three reasons. First, the reports do not include any of the rapid scientific advances that occurred since our original ClimAID report. For instance, the

Worley Parsons report does not account for certain components that influence sea level rise that were considered in the Climate Reports and the IPCC, such as the regional 'fingerprint' of melting land ice or the effects of global land water storage, such as dams and groundwater withdrawal.

Second, as noted above, Worley Parsons chose to consider only a lower-end scenario from our report that does not consider the possibility of rapid ice melt. This is a critical omission, since there has been a growing body of empirical data that the rate of land-based ice melt is accelerating. Numerous studies, including the latest 2013 IPCC Report relative to the prior one of 2007 are now projecting more rapid ice melt and sea level rise than studies from a few years ago. The Worley Parsons reports did not justify this decision to ignore the acceleration of ice melt.

Third, it appears that the Worley Parsons reports linearly extrapolate historic observations of sea level rise into the future. This method is not scientifically sound because sea level rise is projected to accelerate dramatically this century due to increasing concentrations of greenhouse gases and associated warming of the atmosphere and the upper ocean. The linear extrapolation does not account for this acceleration.

For all of these reasons, the projections of sea level rise presented in the Worley Parsons reports are inaccurate, stale, and unreliable. Moreover, by choosing to ignore the more basic 'rapid ice melt scenario' in our original ClimAID study, the Worley Parsons report was selective in its use of the science available at that time by picking the lower of two scenarios without explaining that choice.

Q. DID PSEG-LI ACKNOWLEDGE THAT DATA IN THE REPORTS MAY BE OUTDATED?

A. I believe so, yes. PSEG-LI stated in response to City-33 that "the report was prepared with the best available data at the time." PSEG-LI included the same statement in response to City-36. I interpret these statements as acknowledging that the data underlying the reports is stale. I also disagree that the report used the "best available data at the time," for the reasons set forth in my previous answers.

Q. WHAT SEA LEVEL RISE PROJECTIONS SHOULD PSEG-LI USE AS THE DESIGN BASIS FOR RELEVANT STORM HARDENING PROJECTS?

A. PSEG-LI should consider relying on the projections presented in the Climate Reports, which are 2 to 10 inches by the 2020s, 8 to 30 inches by the 2050s, and 13 to 58 inches by the 2080s. The lower range of sea level rise projections arguably is a weak design basis for an electric system, the reliable operation of which is essential to our modern society. These projections should be reviewed and updated periodically to keep pace with improvements in climate change projections and advances in climate science.

Q. DO YOU HAVE ANY RECOMMENDATION REGARDING EQUIPMENT ELEVATION AND OTHER STORM HARDENING PROJECTS THAT RELIED ON WORLEY PARSONS' SEA LEVEL RISE PROJECTIONS AND ALREADY HAVE BEEN COMPLETED?

A. I recommend that PSEG-LI review those projects to determine whether the underlying design standards are adequate when judged against current sea level rise projections. For projects where the design standard is not adequate, I recommend that PSEG-LI consider the benefit and cost of incremental equipment elevations to address current climate change projections. I recommend that this review should be conducted as part of the holistic collaborative recommended by Mr. Marczewski.

Q. DO YOU HAVE ANY FURTHER CONCERNS REGARDING PSEG-LI'S STORM HARDENING PROGRAM?

A. According to Mr. Marczewski, the program currently appears to be focused entirely (or almost entirely) on assets that were damaged by Hurricane Sandy. This presents a serious risk that other hazards associated with (i) severe weather events other than coastal storms, and (ii) coastal storms with different characteristics such as more rainfall and wind, and less surge, or different strike locations, will be underemphasized. This would leave sections of the LIPA electric system at a higher risk of damage from future climate events. Accordingly, I support Mr. Marczewski's recommendations that a comprehensive collaborative be initiated that studies storm hardening solutions for the entire system, with prioritization for the most vulnerable areas.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

JUDGE PHILLIPS: I believe next it is counsel for LIPA.

MR. BROCKS: Your Honor, I would like to hand you and Your Honors an affidavit for Mr. Kane and Mr. Shansky. Your Honor, the affidavit of Mr. Kane covers the testimony consisting of 18 pages as well as exhibits that were pre-marked Exhibit 3 and Exhibit 4. The affidavit of Mr. Shansky addresses pre-filed testimony consisting of 11 pages, and there are no exhibits with that testimony (handing).

JUDGE PHILLIPS: The affidavit of Mr. Kane has been marked for identification as Exhibit 129. And that basis, we request his direct testimony consisting of 18 pages be copied into the record as though given orally today. The affidavit of Mr. Rick Shansky has been marked for identification as Exhibit 130, and on that basis we ask that his direct testimony consisting of 11 pages be copied into the record as though given orally today.

MR. BROCKS: Thank you.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan

Matter Number: 15-______

DIRECT TESTIMONY OF

KENNETH KANE

LONG ISLAND POWER AUTHORITY

JANUARY 30, 2015

Matter Number: 15-____ Direct Testimony of Kenneth Kane

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Kenneth Kane, CPA, Managing Director of Finance and Budgeting, Long Island Power Authority, 333 Earle Ovington Boulevard, Suite 403, Uniondale, New York 11553.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a BA from Pace University and a MBA in Finance from Hofstra University. I worked in public accounting beginning in 1984 and joined the Long Island Lighting Company ("LILCO") as an accountant in 1988. I joined the Authority in 1999 and served as Director of Financial Reporting until 2001 when I was named Controller. I was appointed Managing Director of Finance and Budgeting in late 2013. I am responsible for the finance and budgeting operations, as well as our efforts to obtain and administer various grants, including those associated with storm recovery and hardening.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents our projections of the Authority's portion of general and administrative ("G&A") expense and the costs of financing the

Authority's electric system, which consists of debt service (including principal and interest expenses and related fees, such as remarketing fees, broker dealer fees, and letter of credit fees). I will also present the projections of amounts that have been deferred and their subsequent amortizations, Federal Grants and Other Income and Deductions, which include grant income. Lastly, I will provide the debt service amounts that are used to determine revenue requirements under the Public Power Model that is discussed in the testimony of Thomas Falcone, the Authority's Chief Financial Officer.

Q. CAN YOU EXPLAIN THE AUTHORITY'S BUDGET PROCESS?

A. Yes. The Rate Plan projections of the Authority's portion of the budget are contained in PSEG Long Island ("PSEG-LI") Ratemaking and Revenue Requirements Panel Exhibit __ (RRP-1), Schedule A-5. The Authority's structure, operations, and staffing have been dramatically changed by the "Amended and Restated Operating Service Agreement" ("OSA"), pursuant to which PSEG-LI became the system operator on January 1, 2014. The Authority's 2015 Budget was prepared through an iterative process involving the department heads and senior executives. The Board adopted the 2015

Operating Budget in December 2014. This filing also contains projected budgets through 2018. Those projected budgets have not been approved by the Board. The Authority presents its budgets for approval in December of each year for the coming year; that is, the budget for 2016 will be presented in December 2015, and so forth.

Q. DOES THE 2015 BUDGET INCLUDE THE AUTHORITY PORTION OF THE OPERATING BUDGET?

A. Yes. The total consolidated 2015 Operating Budget of the Authority and PSEG-LI is $3.6 billion. The 2015 Authority Operating Budget totals $61 million, which includes the expense portion of the PSEG-LI management fee of $35.4 million ($10.0 million of the total fee of $45.3 million, including performance based compensation if fully paid out, will be capitalized). The $61 million excludes approximately $4.5 million of transition costs being deferred. The OSA has established the PSEG-LI management compensation at a fixed annual rate (with escalation clauses based on the CPI), and provides PSEG-LI the ability to earn additional compensation if certain agreed upon levels of performance are reached. The amounts within this case assume that PSEG-LI will reach such performance levels. The Authority's Operating

Expense Budget for 2015 is $25.5 million, a reduction of $13.6 million from 2014. Total Authority staffing is 40 FTE employees, down from approximately 50 employees in 2014 and 100 employees in 2013. Total Authority labor costs, which include salaries and benefits, are budgeted at $10.1 million for 2015, a reduction of $4.6 million from 2014. Professional services in 2015 were budgeted at $9.9 million, a reduction of $7.9 million from 2014. The primary cost changes in professional services are due to reductions in expenses related to the Power Markets Department moving to PSEG-LI, and the absence of fees associated with the Management Audit, FEMA, and CDBG claims administration. The Authority's expenses are shown in the PSEG-LI Ratemaking and Revenue Requirements Panel Exhibit __ (RRP-1), Schedule A-5.

Q. HOW DID YOU FORECAST THE AUTHORITY'S EXPENSES FOR THE THREE-YEAR RATE PLAN?

A. Projected Consolidated Operating Budgets through 2018, including the Authority's projected operating expenses, are presented in PSEG-LI Ratemaking and Revenue Requirements Panel Exhibit __ (RRP-1), Schedule A-5. The Authority's labor is based on a head count of 40, with compensation adjusted for inflation through 2018. Professional services are based on projected activity levels, primarily associated with audits and operator oversight. Each department head who will incur such costs was asked to provide an estimate for the upcoming periods. Such estimates are based upon anticipated work efforts and billing rates.

Q. HAS THE AUTHORITY RECEIVED FEMA FUNDING?

A. Yes. As a public power entity, the Authority is eligible for certain damage reimbursements from the Federal Emergency Management Agency ("FEMA") not available to investor-owned utilities. The Authority estimates that it will spend approximately $806 million to repair and replace its facilities damaged by Superstorm Sandy that struck in October 2012. While normally limited to 75% reimbursement, damage was so extensive that the Authority (and all other New York State applicants) was entitled to 90% reimbursement. We have recovered $704 million from FEMA related to Superstorm Sandy. This was the most expensive storm to ever impact the electrical system on Long Island. In August 2011, Long Island was struck by Hurricane Irene, which at that time was the most expensive storm to strike Long Island's electric grid. The Authority incurred approximately $155 million to repair and replace damaged facilities. LIPA has to date recovered approximately $113 million from FEMA related to Hurricane Irene. In February 2013, Long Island was struck by a nor'ester that was named NEMO. LIPA incurred just over $17 million to restore power after that event. LIPA is working with FEMA to settle that claim. The Federal disaster area was identified as Suffolk County only, and LIPA estimated that approximately 75% of the $17 million of costs noted above was related to damages in Suffolk County. Several meetings have been held with FEMA regarding NEMO, but to date no reimbursement has been provided.

Q. ARE OTHER FEMA BENEFITS AVAILABLE TO THE AUTHORITY?

A. Yes. The Authority has applied for and been awarded 90% funding for a $730 million storm hardening program under FEMA's 428 program. This program is intended to improve system resilience and mitigate the impact of future storms and will also benefit day-to-day reliability. Those incremental capital expenditures are projected to take place from 2014 to 2019. The expenditures for storm hardening and mitigation are in addition to the normal annual Capital Budgets. The Capital Budgets are set out in PSEG-LI's Exhibits, and explained in the PSEG-LI testimony of the Capital Budget Panel.

Q. DOES THE AUTHORITY ANTICIPATE RECEIVING GRANT INCOME?

A. Yes. In September 2014, the Authority signed a Community Development Block Grant ("CDBG") agreement for $143.2 million. The grant is funded by the United Stated Department of Housing and Urban Development ("HUD"). This grant is to reimburse the Authority for some of the non-match FEMA funding related to Superstorm Sandy and Hurricane Irene, and to fund $36 million of storm mitigation protective measures. The storm mitigation protective measures are reflected in the approved Operating Budget for 2015. The Authority had anticipated recovery of the $107 million balance of this grant during 2014. However, $80 million was received in January 2015. The Authority now expects to recover the remaining $27 million during 2015, plus the $36 million for storm mitigation protective measures. The 2015 grant income is budgeted at $76 million, which is down from 2014. Beyond the CDBG grant agreement, grant income is primarily Regional Greenhouse Gas Initiative ("RGGI") funds to support energy efficiency programs of $34.6 million and $3.8 million related to a Build America Bond subsidy. We are projecting grant income of $40.5 million, $45.1 million, and $49.6 million in

2016, 2017, and 2018, respectively. That is shown on PSEG-LI Ratemaking and Revenue Requirements Panel Exhibit __ (RRP-1), Schedule A-9.

Q. WHAT IS THE AUTHORITY'S PROJECTION OF OTHER INCOME AND DEDUCTIONS?

A The Authority expects to generate other income that reduces revenue requirements from a number of sources. Other income includes interest income earned on the Authority's cash balances, the nuclear decommissioning trust fund related to the Authority's 18% interest in Unit 2 of the Nine Mile Point Nuclear Station (the earnings on which remain in the trust), the Suffolk Property Tax Settlement (which offsets the interest expense incurred on the Property Tax Settlement debt issued to fund customer rebates), the Visual Benefits Assessment, the OPEB Account (the earnings on which remain in the account), and other miscellaneous items. Investment earnings on projected account balances are based on reasonable interest rate assumptions for planning purposes provided by the Authority's financial advisor, Public Financial Management, Inc. ("PFM"). That forecast assumes rising interest rates over the Rate Plan period. The Authority has little control over the actual investment earnings, which are dependent on market-based rates of return.

Our projection of Other Income is shown on PSEG-LI Ratemaking and Revenue Requirements Panel Exhibit __ (RRP-1), Schedule A-8.

Q. CAN YOU EXPLAIN DEFERRALS AND AMORTIZATIONS?

A. Deferrals and amortizations are shown on Exhibit __ (KK-1). Deferrals (and their subsequent amortizations) represent items other than physical plant that are placed on the balance sheet after Board approval, which are typically recovered from customers through an amortization over the useful life of the expenditure, unless such recovery period is modified to ameliorate a rate impact. The Authority's deferrals total approximately $3.2 billion. For financial statement reporting purposes, the amortization of such deferrals are projected to be between $212 million and $215 million each year during the period of this Rate Plan. However, under the Public Power Model of rate setting, these amortizations are not explicitly part of the revenue requirement as they are non-cash expenses in each year. Instead, our customers repay the monies borrowed to fund the deferrals at the time the cash expenditure was incurred. It is also important to note that the Authority spreads the recovery of these costs over the period of benefit through the debt issuance used to fund the deferral rather than the amortization period of the deferral, thereby minimizing the current period rate impact. For example, the Authority funded the Outage Management System with bonds that mature over the life of the OSA contract with PSEG-LI, so the period of cost recovery (principal and interest) is aligned with the period of benefit to the customer.

Q. PLEASE CONTINUE.

A. The largest deferral is the Acquisition Adjustment at $2.1 billion. The Acquisition Adjustment represents the unamortized balance of the premium in excess of the book value of plant and certain other assets (customer accounts receivables) that the Authority paid for the acquisition of LILCO in 1998. That premium is being amortized straight-line over a 35-year period that began in June 1998.

The Suffolk Property Tax Settlement ($505 million) represents the unamortized balance of the rebates and credits required to be provided to all ratepayers over the five-year period that began in May 1998 in accordance with the Property Tax Settlement, which includes annual debt service costs on the bonds issued (as part of Bond Series 1998A and 2000A) to finance the Settlement. Beginning in June 2003, Suffolk County customer bills have included a surcharge that is being collected over the succeeding 25-year period to pay the associated debt service.

The Visual Benefits Assessment is the money due from customers in the designated area of the Town of Southampton for the incremental expense of burying a portion of a transmission line.

Debt issuance costs include underwriters' discounts, legal and accounting fees incurred when the Authority issues debt. These costs are amortized over the life of each debt issue in accordance with the provision of GASB 62, which incorporated regulatory accounting (ASC 980/FASB 71) into the governmental standards.

The Authority also deferred the costs it incurred related primarily to facilities owned by others necessary for the operation of the generating stations under contract to the Authority not owned by National Grid. For example, the Authority funded the gas pipe and compressor station necessary to supply natural gas to a recently completed power station, but as those facilities are owned by the local gas distribution company, the costs were deferred and are being amortized over the life of the PPA to Fuel and Purchased Power at a rate of approximately $3 million per year.

Q. WHAT COSTS ASSOCIATED WITH THE TRANSITION HAVE BEEN DEFERRED FOR FUTURE RECOVERY?

A. In order to support the three-year rate freeze that includes 2015, certain costs associated with the transition from National Grid to PSEG-LI as service provider were deferred, including: i) costs expended by the Authority in 2012 through 2013 to prepare for the transition; ii) costs expended on the new Outage Management System ("OMS") and Enterprise Resource Planning ("ERP") system; iii) costs to settle the outstanding pension and other post-employment benefits ("OPEB") with the termination of the National Grid contract; iv) retirement benefits (pension and OPEB obligations) related to the PSEG-LI employees that transitioned from National Grid; v) costs to prepare and support this rate plan; and vi) costs incurred in 2014 to transition the Power Supply Management function to PSEG-LI beginning January 1, 2015. Estimates of the costs that were deferred and the proposed period of recognition in the financial statements are shown on Exhibit __ (KK-1). Each of these deferrals and subsequent amortizations has been approved by the Authority's Board of Trustees.

Q. PLEASE EXPLAIN UTILITY DEPRECIATION EXPENSE.

A. Forecasted depreciation expense for the three years of the Rate Plan is shown on PSEG-LI's Ratemaking and Revenue Requirements Panel Exhibit __ (RRP-1), Schedule A-6. This forecast was prepared by PSEG-LI, which maintains the Authority's plant accounting records under the OSA. Foster and Associates completed a depreciation study on behalf of the Authority in 2014. The study concluded that the Authority's assets have longer useful lives than is currently reflected in depreciation rates, and as such utility depreciation expense is budgeted at $109.4 million in 2015, a reduction of $51.2 million from the 2014 budget. The study also determined that the Authority had a reserve imbalance (surplus) of $815 million. Foster Associates offered four alternative treatments to deal with this imbalance, one of which is to offset that balance against the unamortized balance of the Acquisition Adjustment. As noted in the Foster Associates report, this option would require restating the recorded reserves for each plant account to that which was computed within the study, and transferring the difference to the Acquisition

Adjustment. The report goes on to note that "…this treatment would be fitting for the Authority if service rates are set to produce cash flows sufficient to cover debt service obligations [the public power model] rather than a traditional rate base/rate of return formulation of revenue requirements." As the Authority finds the approach outlined by Foster and Associates to be reasonable, it has been reflected in this filing as being instituted effective January 1, 2016. Accordingly, the unamortized balance of the Acquisition Adjustment will be reduced by approximately $775 million, which is the estimated balance of the reserve imbalance as of January 1, 2016. With the Board's approval, the offset to the Acquisition Adjustment will be recorded at the same time, which will reduce the period of amortization from 35 years to 28 years.

Q **PLEASE DESCRIBE THE AUTHORITY'S CAPITAL STRUCTURE.**

A. Exhibit __ (KK-2) shows the Authority's projected capital structure through 2018. The Capital Budget for 2015 was approved by the Board in December 2014 and was provided to the DPS in January 2015. The projected Capital Budgets for 2016 to 2018 are described in the testimony of PSEG-LI's Capital Panel.

Q. PLEASE DESCRIBE THE AUTHORITY'S INTEREST EXPENSE.

A. Interest expense is projected to be $365 million in 2015. Projected expense for the three years of the Rate Plan is shown on PSEG-LI Ratemaking and Revenue Requirements Panel Exhibit __ (RRP-1), Schedule A-10. The projection of interest expense is based on the amount of debt outstanding in each year, the interest associated with each series, and the amortization of expenses related to the issuance of each series (cost of issuance, bond premiums or discounts, and deferred gains or losses on early retirement of debt). Interest and related expenses are forecast to be $345 million in 2016; $346 million in 2017; and $360 million in 2018. The forecasted cost for new tax exempt debt is 4.5% for 2015, increasing to 5.0% in 2018. Short-term variable rate instruments are assumed to cost 0.375% in 2015 escalating to 2.5% in 2018. The interest rates used to calculate interest expense are provided by the Authority's financial advisor, PFM, and are reasonable planning assumptions.

Q. WHAT IS DEBT SERVICE AND HOW IS IT DIFFERENT FROM INTEREST EXPENSE?

A. Interest expense is the amount of interest and related expense that is recognized in the financial statements each year in accordance with generally accepted accounting principles. It is not necessarily cash paid. Debt service is the amount of principal and interest paid each year to bond holders. Debt service schedules are established for each bond when it is issued, and must be paid according to that schedule to avoid defaulting on that bond. As described in the testimony of Thomas Falcone, the rating agencies look at the coverage required on the Authority's fixed obligations, which looks not only at debt, but "debt-like" obligations, such as payments made under capitalized leases. The fixed coverage ratio is often used by investors and rating agencies, and as such will be shown in this case. For capitalized leases, LIPA also prepares a minimum lease payments table that shows the fixed monthly payments over the life of the lease, which must be paid to avoid defaulting on the lease.

Total debt service (including LIPA and UDSA) is included in PSEG-LI Ratemaking and Revenue Requirements Panel Exhibit __ (RRP-1), Schedule A-11, and is estimated at $573 million, $547 million, and $592 million in 2016, 2017, and 2018, respectively, before giving effect for the savings from the proposed securitization legislation. With refinancing, total debt service is projected at $502 million, $518 million, and $538 million in 2016, 2017, and 2018, respectively. This projection assumes significant bond refinancing savings using the Utility Debt Securitization Authority, as illustrated in the Exhibit and described in Authority Witness Falcone's testimony. Debt service associated with existing debt will be approximately $497 million, $496 million, and $463 million in 2016, 2017, and 2018, respectively, if the refinancing savings are achieved as projected. Debt service associated with new debt issued during the period of this case to fund system improvements will be approximately $4 million, $18 million, and $35 million in 2016, 2017, and 2018, respectively.

As noted in the testimony of Mr. Falcone, coverage on debt service plus capitalized lease obligations (fixed obligation coverage) is a commonly used metric by investors and rating agencies. The Authority's debt-related recoveries, including debt service and coverage requirements, are projected at $623 million in 2016, $681 million in 2017, and $742 million in 2018. Coverage on fixed obligations is projected to be $121 million in 2016, $163 million in 2017, and $205 million in 2018.

Q. DOES THIS COMPLETE YOUR PRE-FILED DIRECT TESTIMONY AT THIS TIME?

A. Yes.

BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan

Matter Number: 15-_____

DIRECT TESTIMONY OF

RICK SHANSKY

LONG ISLAND POWER AUTHORITY

JANUARY 30, 2015

Matter Number: 15-____ Direct Testimony of Rick Shansky

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Rick Shansky, Managing Director of Contract Oversight, Long Island Power Authority ("Authority"), 333 Earle Ovington Boulevard, Suite 403, Uniondale, New York 11553.

Q. WHAT ARE YOUR RESPONSIBILITIES AT THE AUTHORITY?

A. I direct the Authority's oversight of its primary contractor PSEG Long Island ("PSEG-LI"), as well as its affiliate that performs day-to-day power and fuel procurement. I am also responsible for managing the Authority's participation in wholesale power markets.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science in Electrical Engineering from Rensselaer Polytechnic Institute and a Master of Science in Energy Management from NY Institute of Technology. I am licensed as a Professional Engineer in the State of New York. I have more than 30 years of experience in the electric utility industry, and previously held positions at Consolidated Edison Company of New York ("Con Edison") and the Long Island Lighting Company ("LILCO") in the areas of energy management, resource planning, fuel and purchased power, and generation planning. I joined the Authority in 2008 and held management positions in the Power Markets department before assuming my current position in September 2014.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN RATE PROCEEDINGS IN NEW YORK STATE?

A. Yes. I testified as a witness for Con Edison in Public Service Commission ("PSC") Cases 07-S-1315, 05-S-1376, 03-S-1672, 99-S-1621, and 94-E-0334.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the Authority's oversight of PSEG-LI's operations.

Q. HOW IS THE AUTHORITY ORGANIZED TO CONDUCT OVERSIGHT?

A. The Authority's Overview Panel testimony explains how the Authority is organized. While each department within the Authority plays a role in the oversight process, the Contract Oversight Department, which consists of nine positions, is dedicated to overseeing PSEG-LI's performance of operations services under the Amended & Restated Operations Services Agreement

("OSA"). The Overview Panel explains the background of the OSA in its testimony. The Contract Oversight Department is staffed with experts in the areas it covers, including transmission and distribution system operation, power and fuel procurement and planning, energy efficiency program management, and customer service, among others. When appropriate, we can supplement our staff with technical consultants who may be engaged to investigate particular issues. During 2014, we engaged several consultants to assist with the verification of data used by PSEG-LI in reporting its performance under the metrics established by the OSA. The department also carries out contract administration of the OSA, administers PSEG-LI's performance metrics, and advises Authority Staff and the Board of Trustees on OSA matters, including approval of budgets, rate plans, and power contracts. Periodically, we report such matters to the Contract Oversight Committee of the Board of Trustees, which leads the Board's oversight of PSEG-LI. During 2014, the Committee held sessions involving a variety of issues, including staff's oversight process, OSA performance metrics, PSEG's operational readiness, and process improvements, such as PSEG-LI's new outage management system ("OMS"). We also manage the Authority's response to customer appeals on tariff or service issues that sometimes arise following determinations by PSEG-LI and DPS-LI; direct the activities of PSEG Energy

Resources & Trade, the PSEG-LI affiliate that conducts day-to-day procurement of fuel and power for the Authority; and coordinate PSEG-LI's representation of the Authority in various rulemaking processes by the regional market operators and in State regulatory proceedings, such as the PSC's REV proceeding.

Q. WHAT IS THE PURPOSE AND GOAL OF CONTRACT OVERSIGHT?

A. Under the OSA, PSEG-LI is the "name and face" of electric utility service on Long Island, and it is responsible for management, operation, and maintenance of the Long Island utility system, including power supply planning and procurement. The OSA reserves decision-making authority to the Authority in certain areas, such as approval of rates and budgets and power contracts. In most other areas, the Authority carries out its oversight by assessing and enforcing PSEG-LI's compliance with the performance standards in the OSA, which include performance metrics and associated incentive compensation in key areas, such as cost control, reliability, and customer satisfaction. The 2013 NorthStar audit report summarized the goal of oversight: "The service provider contract must drive performance, allowing LIPA to exercise its responsibilities as system owner and intervene as necessary to improve performance." (NorthStar audit report, p. 1-6). Thus, the Authority monitors

PSEG-LI's operations and activities, assesses performance and consistency with established regulations and policies, and provides feedback to PSEG-LI as appropriate.

Q. PLEASE DESCRIBE THE PERFORMANCE MONITORING PROCESS.

A. While the process begins with monitoring the OSA performance metrics, it is much more than that. Each month, PSEG-LI prepares a detailed report on its performance against targets for the 20 high-level (*i.e.*, Tier 1) metrics specified in the OSA in the areas of technical performance, customer satisfaction, and financial performance. The report also provides data on a greater number of Tier 2 metrics, though not tied to incentive compensation, provide a broad view of PSEG-LI's operation of the utility. The monthly report provides trend analysis and breaks down each metric into component parts (*e.g.*, location or cause), which facilitates identification of problems and highlights successes. This information is reviewed with Authority staff and senior management at monthly meetings, during which the need for follow-up actions may be determined. Process reviews of PSEG-LI's performance reporting are also done. These detailed reviews validate the calculations, data exclusions, and associated controls from original data entry in the field through the end report that is generated by PSEG-LI's information systems. These reviews are conducted for each performance metric in the first year of use or when a process change is introduced. During 2014 we conducted such reviews for all of the Tier 1 metrics. During the first quarter of 2015, PSEG-LI will submit documentation of its 2014 performance for review by the Authority and the New York State Department of Public Service ("DPS").

In addition to the OSA performance metrics, we monitor key operating activities, such as field activities, staffing levels, customer collections, through review of reports and direct observation. PSEG-LI's progress on capital projects is assessed at project review meetings and review of monthly variance analysis. An area of particular interest in 2014 was PSEG-LI's development of a new outage management system ("OMS"). When a storm occurs, we monitor PSEG-LI's preparation and its response, and ascertain its compliance with the emergency response plan that it submitted to the DPS. A detailed review of each storm's expenses is also conducted. On a day-to-day basis, we observe PSEG-LI's activities, review incident reports and follow-up actions, and interact with PSEG-LI on numerous matters. During 2014, the Authority assessed PSEG-LI's performance in responding to outages following more than a dozen storms, as well as its response to several high voltage cable failures that did not cause any customer outages. We also requested and received analyses of the cause and duration of distribution outages, even when not a result of a storm, and we assessed PSEG-LI's readiness to meet peak loads and its compliance with federally mandated reliability rules.

Q. WHAT OTHER ACTIVITIES DOES CONTRACT OVERSIGHT PERFORM?

A. Each year we review and make recommendations to the Authority's Board of Trustees regarding PSEG-LI's capital and operating budgets. We also reviewed PSEG-LI's Utility 2.0 Long Range Plan, and will continue to do so annually. In addition, as noted above, we oversee and coordinate PSEG-LI's representation of the Authority in wholesale market stakeholder processes before regulatory bodies, including the PSC, where applicable to utility service on Long Island.

Q. DOES THE AUTHORITY COORDINATE ITS OVERSIGHT WITH DPS?

A. Yes. The Authority's oversight complements that of the DPS, and we consult with the DPS to avoid any unnecessary duplication of effort. While the DPS conducts oversight that is analogous to its role with respect to the investor-owned utilities in New York State, the Authority's oversight is aimed at carrying out its contractual obligations under the OSA, and assuring that its interests as asset owner on behalf of our customers are being served.

Q. HAS THE AUTHORITY REVIEWED PSEG-LI'S PROPOSED 2016-2018 BUDGETS?

A. Yes, we have. Authority staff met with PSEG-LI to review the proposed 2016-2018 budgets. We evaluated the proposed spending levels for consistency with actual 2014 and proposed 2015 levels, as well as PSEG-LI's planned change initiatives. Our review was aided by PSEG-LI's responses to approximately 100 questions from Authority staff, and was also coordinated with staff of the DPS Long Island Office. As a general matter, we ascertained that PSEG-LI had reasonable methods for establishing these budgets, and that the budgets were intended to support the maintenance or attainment of performance goals under the OSA. It should be noted that the review of PSEG-LI operating costs is an ongoing process.

Q. WHAT MAJOR INITIATIVES DOES THE AUTHORITY PLAN TO OVERSEE IN 2015?

A. We look forward to reviewing PSEG-LI's development of an Integrated Resource Plan ("IRP") during 2015, which will address many important power supply issues, including integration of renewable and distributed resources, repowering of the former LILCO power plants, and a strategy for restructuring the Authority's power contract portfolio to achieve cost-effective, reliable service. We also expect PSEG-LI to continue to actively participate in the PSC's REV proceeding and to incorporate that vision into its planning and operations. Along with these activities, the Authority will continue to assess PSEG-LI's progress toward achieving the OSA's performance goals, as well as any changes in the performance metrics that may be appropriate to maximize their effectiveness and to focus the metrics on areas that are determined to be important for quality electric service.

Q. YOU MENTIONED THE AUTHORITY'S CONTRACT PORTFOLIO. HAVE THERE BEEN ANY CHANGES IN THOSE CONTRACTS NOW THAT PSEG-LI AND ITS AFFILIATE HAVE ASSUMED RESPONSIBILITY FOR THE AUTHORITY'S POWER SUPPLY?

A. No, but the contracts are now administered and managed by PSEG-LI. In accordance with the OSA, PSEG-LI is now performing all of the functions of the Authority's former Power Markets department, except for decision-making and wholesale market policy responsibilities that remain with the Authority. Accordingly, the Authority retains title to the power it purchases under its power contracts; but PSEG-LI, which is responsible for managing the overall cost of such power, now exercises the Authority's rights under the contracts.

Q. ARE ANY COSTS INCURRED UNDER POWER SUPPLY CONTRACTS INCLUDED IN THE THREE-YEAR RATE PLAN?

A. The cost of the Power Supply Agreement ("PSA") with National Grid Generation LLC ("NGG") is currently collected through delivery rates.

Q. PLEASE EXPLAIN HOW CHARGES UNDER THE PSA CAN VARY?

A. The PSA is a cost-of-service contract, which means that NGG recovers its operating costs plus a return of and on the capital it invests in its plants ("Carrying Charges"). NGG's rates are filed with and approved by the Federal Energy Regulatory Commission ("FERC"). While the Authority (through PSEG-LI as its agent) has the right to approve (or reject) NGG's proposed capital budgets for its power plants, such investments may be required for NGG to comply with government regulations and to meet the performance standards set in the PSA. Under the rate formula approved by FERC, capital investments in a given year are added to NGG's rate base and result in increased Carrying Charges in the next year. Certain costs, including property taxes, and pension-related expenses, are subject to annual adjustment and can be very difficult to predict. The PSA originated in 1998 as a vehicle for assigning the cost of the former LILCO power plants to the Authority. The original PSA expired in 2013. An amended and restated PSA took effect in 2013 and will expire in 2028. However, the Authority has the right to terminate the PSA as early as 2025. During the term of the PSA, the Authority also has the right to direct NGG to repower certain plants or to remove any or all of the plants from the contract in exchange for a lump sum payment to NGG. Such decisions, which will be studied by PSEG-LI in the IRP, can also substantially change the Authority's costs under the PSA.

Q. DOES THIS COMPLETE YOUR PRE-FILED DIRECT TESTIMONY AT THIS TIME?

A. Yes.

JUDGE PHILLIPS: I believe that concludes the witnesses and testimony that were going to be entered today by affidavit; is that correct?

MR. WEISSMAN: Correct.

JUDGE PHILLIPS: Everyone is nodding. Do we have any other matters that we need to address before we turn to whether or not to enter the exhibits that have been marked.

MR. FAVREAU: At this time, do we want to discuss the exhibits containing the IR responses from PSEG or want to wait until tomorrow?

JUDGE PHILLIPS: I see a head shaking no in the audience.

MR. FAVREAU: I leave it up to you, Your Honor.

JUDGE PHILLIPS: At this point we would like to address that tomorrow. I think some people need a break at this point. Are there any other matters before we turn to whether or not to admit the exhibits that have been marked to into the record? No? So, absent any objections, the exhibits that we have marked today have gone from Exhibit 1 through Exhibit 130. They will be loaded into the record absent any objection. Objections?

MR. BROCKS: No objection.

JUDGE PHILLIPS: Barring none, we now have our first 130 exhibits. Are there any other matters.

MR. FAVREAU: Your Honor, I'm sorry.

JUDGE PHILLIPS: Use your microphone.

MR. FAVREAU: The exhibits I think that are in question that are PSEG's IRs they are attempting to introduce themselves, I think they are listed as 98 and 99, those I think are the same type of exhibits that we are going to put off until tomorrow.

MR. WEISSMAN: That's correct.

MR. FAVREAU: We will be objecting to those. I don't know if you want to keep a placeholders or how you want to do that.

JUDGE PHILLIPS: On the basis of what you just stated, you said it is 98 and 99; is that correct.

MR. FAVREAU: I believe that is what we have; is that correct?

MR. WEISSMAN: That's correct.

JUDGE PHILLIPS: I will amend my previous statement. We do have objections to exhibits that were marked as 98 and 99. Excluding those, the other exhibits will be entered into the record and we will reserve and discuss tomorrow whether or not to enter exhibits that have been pre-marked for identification as 98 and 99; is that correct.

MR. FAVREAU: Correct, Your Honor.

MR. WEISSMAN: Correct.

JUDGE PHILLIPS: Everyone is nodding yes and is saying yes. Again, any other matters before we adjourn? Any objections to starting again at 9:30 tomorrow.

Hearing none, I will note for the record that we will adjourn but we will resume here tomorrow at 9:30 a.m. I thank everyone for their time.

(Whereupon, the Evidentiary Hearing was adjourned, 2:34 p.m.)

C E R T I F I C A T E

I, Laurae Cohen, a reporter and Notary Public within and for the State of New York, do hereby certify:

That the witness(es) whose testimony is hereinbefore set forth was duly sworn by me, and the foregoing transcript is a true record of the testimony given by such witness(es).

I further certify that I am not related to any of the parties to this action by blood or marriage, and that I am in no way interested in the outcome of this matter.

Laurae Cohen

LAURAE COHEN