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 Exhibits of:

T&D Capital Expenditures Panel

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Index of Exhibits

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Relied Upon Responses to Information Requests

Index of Exhibit__(CEP-1)

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0244
Date of Response: 03/11/2015
Witness: CAPITAL BUDGETS

Question:
For the In-Flights, New Regulatory, New Load Growth, New Reliability, New Other and N-1-1 projects shown in Exhibit (CBP-2), for each project:
a. Provide the cost estimate grade (Order of magnitude, conceptual, etc.).
b. Provide the in-service date.
c. Provide the percentage completed as of December 31, 2014.
d. Identify whether the project was initiated by PSEG-LI or was initiated prior to the OSA.
e. Provide the estimate grade at the time PSEG-LI assumed responsibility for the project's completion, where applicable.

Attachments Provided Herewith: 1
DPS-CBP_0244_Exhibit - DPS_CPB-2_IR_244_r4.pdf

Response:

a: Projects included in the budget were done prior to implementation of PSEG LI's estimating process. The estimates are at a conceptual level.
b: See attached file - column b
c: See attached file - column c
d: See attached file - column d
Note that in many cases these projects were identified as future potential needs. As such, conceptual work and looking for sites to construct facilities were started, e.g., Nassau Hub, Kings Highway, Riverhead to Eastport. No detailed cost estimates were prepared.
e: Prior to PSEG LI becoming the service provider for LIPA, there were essentially two estimate grades: there were detailed estimates for near term projects, e.g., next year, and then conceptual estimates for the balance of projects.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0246
Date of Response: 03/11/2015
Witness: CAPITAL BUDGETS

Question:
Provide the internal studies mentioned on page 32 of the Capital Budget Panel's testimony that were conducted for the Syosset to Shore Road 138 kV circuit. Discuss what alternatives were considered including REV like projects.

Attachments Provided Herewith: 0

Response:
Preliminary planning studies were performed in order to help identify the impact to the change in the NERC Bulk Electric System (BES) definition. The new NERC BES definition has a significant impact on LIPA, as essentially the entire LIPA 138kV system and the associated elements will now be subject to applicable NERC Reliability Standards. The presentation entitled Preliminary NERC BES GAP Analysis N-1-1 Study for Existing System Based on the Existing TPL Standards Network Strategy Planning (May 8, 2013) summarizes the initial studies that were conducted to evaluate the impact of the revised BES definition on the LIPA system. The impact is being assessed continuously as the BES related discussions are ongoing with NYISO and other transmission owners which in turn provide additional clarity with respect to the interpretation of TPL standards. The presentation contains Confidential Critical Inrastucture Information and therefore is being provided to the DPS Records Access Officer with a request for confidential treatment.

We note that official NERC TPL Standard compliance studies (i.e., TPL Planning Assessments) will be performed and coordinated with the NYISO. Such studies, which are expected to be completed in early 2016, will utilize the 2015 FERC 715 base cases issued by the NYISO as a foundation. The studies will confirm and identify the need for the aforementioned projects as corrective action plans. Other corrective action plans to meet compliance will also be considered.

Several alternatives, summarized below, have been considered along with the recommended project which is the new 138 kV circuit between Syosset to Shore Road.

1. New East Garden City to Lake Success 138 kV cable including Phase Angle Regulator
2. New East Garden City to Lake Success to Shore Road 138 kV cable including Phase Angle Regulator
3. New East Garden City to Shore Road 138 kV cable Including Phase Angle Regulator
4. New Valley Stream to Lake Success 138 kV cable
5. New Syosset to Shore Road 138 KV cable Including Phase Angle Regulator
6. Resource addition at Glenwood combined with load relief (REV like project)

REV like projects will be considered in the Glenwood area based on the results of planned RFP solicitations for distributed resources combined with load relief. The magnitude of load relief required to solve the need for reinforcement is in the range of 100-200 MWs. The cost effectiveness of distributed resources combined with load relief solutions, along with the ability of the REV solutions to achieve in-service dates necessary to support system reliability, will determine final recommendation.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0247
Date of Response: 03/11/2015
Witness: CAPITAL BUDGETS

Question:
Provide the internal studies mentioned on page 32 of the Capital Budget Panel's testimony that were conducted for the East Garden City to Valley Stream 138 kV circuit. Discuss what alternatives were considered including REV like projects.

Attachments Provided Herewith: 0

Response:
Preliminary planning studies were performed in order to help identify the impact to the change in the NERC Bulk Electric System (BES) definition. The new NERC BES definition has a significant impact on LIPA, as essentially the entire LIPA 138kV system and the associated elements will now be subject to applicable NERC Reliability Standards. The presentation entitled Preliminary NERC BES GAP Analysis N-1-1 Study for Existing System Based on the Existing TPL Standards Network Strategy Planning (May 8, 2013), which is being provided in response to Request DPS-CBP-0246, summarizes the initial studies that were conducted to evaluate the impact of revised BES definition on LIPA system. The impact is being assessed continuously as the BES related discussions are ongoing with NYISO and other transmission owners which in turn provide additional clarity with respect to the interpretation to TPL standards. The presentation contains Confidential Critical Inrastucture Information and therefore is being provided to DPS Records Access Officer with a request for confidential treatment.

We note that official NERC TPL Standard compliance studies (i.e., TPL Planning Assessments) will be performed and coordinated with the NYISO. Such studies, which are expected to be completed in early 2016, will utilize the 2015 FERC 715 base cases issued by the NYISO as a foundation. The studies will confirm and identify the need for the aforementioned projects as corrective action plans. Other corrective action plans to meet compliance will also be considered.

Several alternatives, summarized below, have been considered along with the recommended project which is the new 138 kV circuit between East Garden City to Valley Stream.

7. New 138kV circuit from Barrett to Valley Stream (Barrett to Valley Stream 3rd 138kV circuit)
8. New 138kV circuit from Barrett to East Garden City (bypassing Valley Stream)
9. Changing the wheel split via 901 and 903 to Jamaica
10. New 138kV circuit from Barrett to Far Rockaway to Valley Stream

11. New 138kV circuit from East Garden City to Valley Stream (EGC to Valley Stream 2nd 138kV circuit)
12. Resource addition at Far Rockaway combined with load relief (REV like project)

REV like projects will be considered in the Far Rockaway area based on the results a planned RFP solicitations for distributed resources combined with load relief. The magnitude of load relief required to solve the need for reinforcement is in the range of 100-200 MWs. The cost effectiveness of distributed resources combined with load relief solutions , along with the ability of the REV solutions to achieve in-service dates necessary to support system reliability, will determine final recommendation.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0303
Date of Response: 03/27/2015
Witness: CAPITAL BUDGETS

Question:
Provide a detailed explanation for the budget increase from $1,426,180 in year 2017 to $6,929,636 in year 2018 for the Substation Reliability Enhancement Program found in Exhibit CBP-2 of the Capital Budget Testimony.

Attachments Provided Herewith: 0

Response:
The main drivers for the increase in spending from 2017 to 2018 are:

EGC - Replace 20MVA 69kV-23kV Bank 7 with a 28MVA bank
This should have been categorized as a specific project since it is estimated at greater than $1 million. The reason for the replacement is as described in PJD B26.3 – Transformer Replacements. This PJD describes a program that includes multiple locations.

Redesign & Rebuild Load Tap Changers on Valley Stream; Northport & Spare Phase Shifters
These tap changer redesign and rebuilds are on equipment that have higher ratings and are significantly more costly and complex than the distribution bank tap changer replacements scheduled in 2017.

During this review it was identified that the PJD for the Redesign & Rebuild Load Tap Changers on Valley Stream; Northport & Spare Phase Shifters was not included in the PJDs previously sent. The PJD is being provided to the DPS Records Access Officer with a request for confidentiality because it includes confidential Critical Infrastructure Information and intra-agency deliberative information.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0318
Date of Response: 03/27/2015
Witness: CAPITAL BUDGETS

Question:
a. Provide a breakdown of the spending allocation for the "New Business" line item shown on Exhibit CBP-2 page 1 of 4 for calendar years 2016, 2017 and 2018 in terms of PJD references B3.1 (New Business Expenditures), B3.2 (CIPUD), B3.3 (Underground Residential Development) and B3.4 (Underground Residential Development Services).
b. Provide 2014 actual expenditures for PJD reference B3.1, B3.3 and B3.4 as well as historical expenditures for PJD reference B3.2 for each calendar year 2010 through 2014.
c. Explain how 2015 budgets were calculated from historic data and how 2016, 2017 and 2018 budgets were projected from the 2015 budget.
d. Provide the historic and projected mix of work performed using in house and contractor resources as well as justification.

Attachments Provided Herewith: 2
DPS-CBP_0318_NewBusiness 2016 - 2018.xlsx
DPS-CBP_0318_NewBusiness Hist Spend 2010 - 2014.xlsx

Response:
a. Please see attached document "New Business 2016 – 2018."
b. Please see attached document "New Business Hist Spend 2010 – 2014."
c. The 2015 budget was prepared by considering historical spending from 2011 through 2013 and the 2014 spending forecast as of September 2014. The spike in spending from 2012 to 2013 was attributed to post Hurricane Sandy customer rebuilding activities. The budget for years 2016 through 2018 represents a year over year escalation of 3% from the 2015 budget.
d. For 2010 through 2012, the mix of in in-house versus contractor labor (by dollars) was approximately 25 % in-house. In 2013, the mix (by dollars) was approximately 40% in-house.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0335
Date of Response: 04/01/2015
Witness: CAPITAL BUDGETS
QUESTION ON CII - CONFIDENTIAL STATUS

Question:
Project Justification Document (PJD Reference: S44.1 references five projects listed on Exhibit_(CBP-2):

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
5) Fire Island -Brightwater-Captree Upgrade OH 23-747 Transmission Supply

a. For each project above provide all engineering studies that show which of the three contingencies (or combination thereof) mentioned in PJD S44.1 is addressed by the respective projects.
b. Specifically discuss why each project needs to be in-service by the dates shown in the Company's response to DPS_CBP-244 with special elaboration on the project(s) associated with the "third most important" contingency described in PJD S44.1 that seemingly has a need date of 2024.
c. Provide a detailed cost breakdown for each project.
d. Provide a detailed schedule for each project.
e. What are the estimated hours of exposure per year for loss of load for each of the three contingencies mentioned in PJD S44.1.
f. Explain how each project or combination of projects meets the N-1-1 criteria for each of the 3 contingencies described. Specifically explain how the full load will be served in an N-1-1 situation after the projects are completed.
g. Provide a single line diagram showing the normal, STE and LTE flows on each line before and after the projects for each contingency described in PJD S44.1.
h. For each load area affected by the three contingencies mentioned in PJD S44.1 describe what type of REV like projects were taken into account to mitigate or eliminate the amount of load left unserved after distribution load transfers or other operational measures.

Attachments Provided Herewith: 0

Response:
a. Engineering studies are provided document "Fire Island N-1-1_DPS_CBP_0335." The "Solution Matrix" identifies correlations between specific projects and specific contingencies. This document contains confidential Critical Infrastructure Information and is being provided to the DPS Records Access Officer with a request for confidential treatment.

Note that the need for N-1-1 solution for improvement of reliability of the Fire Island load area is driven by aging transmission cables (historical failures and escalating probability of future failures), long repair/replacement time (especially in a case of underwater cables), and limited possibility of using emergency generation. Analysis is based on historical and projected failure rates of aging transmission cables in the Fire Island load area for projected load increase over 10 years (case studies are done for 2014 and for 2024).

b. Current investment plan and projects are primarily focused on addressing contingencies of the first and second priority (as presented in the PJD document). The "third most important contingency" is developed and provided as additional information for the evaluation of alternatives (technical and cost aspects) chosen to address these contingencies as a whole. Collectively, these projects were recommended for addressing these contingencies based upon the joint assessment of the contingencies risk of failure, the contingencies resulting in unserved load, and the time in which these risks are associated. The "in-service" dates and priorities of these multi-tiered projects were determined with this method. For instance, projects #1and #2, having a high risk of failure and a resultant high amount of unserved load, respectively, are included in the 2015 budget (development of engineering design and detailed technical/cost project planning) with a planned completion time of 2018 and 2017, respectively. In regard to the third contingency, the projects associated with alleviating its risk of failure have the latest in-service dates assigned to them due to their corresponding need being furthest in the future.

c. Cost breakdown for each project and year is provided within response to DPS-CBP-244. The following additional information is provided for further clarification. Project costs are provided as the response to DPS-CBP-244 are based on estimates and historical cost of similar projects for similar operating conditions, and preliminary designs and engineering analysis. Each project is planned as a multiyear project. The first year of the project is planned for development of a detailed design and an engineering solution, and for development of detailed project cost and schedule plans. It is expected that cost and schedule for subsequent years will be adjusted based on detailed design and cost estimates developed in the first year of a specific project.

d. See response to question "c".

e. (see definition of acronyms at the end of this response)

- Contingency 1 had an estimated 3672 hours (the full summer) of exposure to unserved load due to this contingency
- Contingency 2 had an estimated 2194 hours of exposure to unserved load due to this contingency
- Contingency 3 had an estimated 3672 hours (the full summer) of exposure to unserved load due to this contingency

f. Only one of the following projects directly eliminates an N-1-1 contingency risk. The remaining projects were recommended as a combined solution which also addresses the overall root reliability issues within the Fire Island load area.

1. Captree-Robert Moses Trans. Cable Circuit 23-738
   This project helps with the second N-1-1 contingency, Captree to Robert Moses & Fair Harbor to Ocean Beach, in that it decreases the overall failure rate of the Captree to Robert Moses circuit.
2. Ocean Beach-Fire Island Pines Transmission Cable Life extension & N-1-1
   This project directly alleviates the risk of overload due to the first N-1-1 contingency, Fire Island Pines to Bayport & Ocean Beach to Fire Island Pines, because it provides an additional feed into Fire Island Pines (FIP), thereby serving the entire load at Fire Island Pines.
3. Ocean Beach Fair Harbor & Robert Moses-Fair Harbor Cables 23-749 & 23-742
   This project helps with the second N-1-1 contingency, Captree to Robert Moses & Fair Harbor to Ocean Beach, in that it decreases the overall failure rate of the Fair Harbor to Ocean Beach circuit.
4. Bayport-Fire Island Pines and Other Circuits Splices Improvements
   This project helps with the first and third N-1-1 contingencies (Fire Island Pines to Bayport & Ocean Beach to Fire Island Pines, and Fire Island Pines to Bayport & Ocean Beach to Watson) in that it decreases the overall failure rate of the Bayport-Fire Island Pines circuit.
5. Fire Island -Brightwater-Captree Upgrade OH 23-747 Transmission Supply
   This project helps with the third N-1-1 contingency, Fire Island Pines to Bayport & Ocean Beach to Watson, in that it increases the overall capacity and consequent LTE rating found on the Brightwater to Captree (23-747/736) circuit.

g. The load flow output diagrams are being provided to the DPS Records Access Officer because they contain confidential CII.

h. 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. This is particularly true given the REV addition (*e.g.*, solar) would also be outaged for an N-1-1 contingency since it requires the availability of transmission and energization of the grid to operate and serve customer load. System upgrades/changes in the Fire Island area are designed to collectively alleviate these reliability risks to an acceptable level as the most appropriate area solution.

Acronyms:

- Contingency 1: failure of Fire Island Pines-Bayport & Ocean Beach-Fire Island Pines
- Contingency 2: failure of Captree-Robert Moses & Fair Harbor-Ocean Beach
- Contingency 3: failure of Fire Island Pines-Bayport & Ocean Beach-Watson

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0348
Date of Response: 04/01/2015
Witness: CAPITAL BUDGETS

Question:
Project Justification Document (PJD) Reference S48.1, under the section of "problem definition" states, "At least two switching errors within the past 5 years have been directly related to the overall crowding of the current control room big board. With the 138 kV system becoming part of BES in 2016, switching errors could put us at risk to incur various fines and penalties as high as potentially $1 million per day / per violation."
a) Provide internal reports that were conducted following the two switching errors mentioned above.

b) Explain in detail how switching errors could put the Company at risk to incur various fines and penalties with the 138 kV system becoming part of BES in 2016.

c) Provide the rules or standard that supports the statement "With the 138 kV system becoming part of BES in 2016, switching errors could put us at risk to incur various fines and penalties as high as potentially $1 million per day / per violation."

Attachments Provided Herewith: 1
DPS-CBP_0348_NERC Sanctions.pdf

Response:

a) The switching incidents referred in the Project Justification Document (PJD) Reference S48.1, under the section of "problem definition", are predated to PSEG-LI and hence reports pertinent to these incidents are not in PSEG-LI records.

   A description of the incidents is provided below.

   Switching Incident #1
   On 01/25/2011, during scheduled switching at 5M Newbridge Road, incorrect breakers were operated. This open ended 138 kV circuit 138-562. The congestion on the control room board was a contributing factor.

   Switching Incident #2
   On 02/01/2013, while performing emergency clearance switching on 33kV circuit 33-312, there was an unintended momentary outage to 4kV Banks #1 and #2 at 2R Hewlett. The congestion on the control room board was a contributing factor.

b) If the investigation of the switching error determines that an applicable NERC Reliability

Standard or requirement approved by the Federal Energy Regulatory Commission may have been violated, the entity is required to report the possible violation to the Regional Entity for formal assessment to determine if a violation existed. In addition, FERC and/or NERC may institute an investigation following an incident and assess penalties if a NERC Reliability Standard violation is found to have been violated.

c) Appendix 4B of the NERC Rules of Procedure describes the Sanction Guidelines of NERC that they may levy against entities for violations of the Requirements of NERC Reliability Standards approved by the Federal Energy Regulatory Commission. Appendix A of this document describes the maximum amount of $1,000,000 per day that could be applied for each day that a violation continues. See attachment Appendix 4B

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0349
Date of Response: 03/27/2015
Witness: CAPITAL BUDGETS

Question:
In Exhibit-CBP-2, the proposed budgets for the above project are $5M in 2016, $25M in 2017, and $20M in 2018.
a. Provide a detailed cost breakdown of the proposed budgets in each rate year from 2016 to 2018. The cost breakdown should be included, but not limited to labor, materials, overhead, contingencies, and/or other indirect costs.

b. Provide the current project status of the first phase, including the amount spent on the project to-date.

c. Provide any internal justification documents that the Company has submitted to senior management beyond the PJD.

d. Fully explain why the current control room in Hicksville cannot be expanded to another adjoining room or done through a building expansion.

Attachments Provided Herewith: 0

Response:

a. The preliminary estimates in Exhibit-CBP-2 for the project are based on high level discussions with the Engineering Firm Robert Lamb. The estimates, being at the preliminary stage, do not provide a detailed cost breakdown.

b. Based on the high level discussions with the vendor, preliminary estimates were provided.

   The project phase 1 scope to conduct a study to firm up the project details, timing and costs, has not yet been approved to proceed by the PSEGLI Utility Review Board for 2015.

c. No additional documents have been prepared at this time.

d. The present PSEG-LI LIPA transmission control center is located on the National Grid property in Hicksville. The space has constraints for vertical as well as horizontal expansion as we share the building and the floor with National Grid gas operations.

   With the continuous load growth in the LIPA service area, several new transmission substations and circuits were added and are being added to the LIPA system. Several existing substations were reconfigured or are in the process of redesign to increase reliability (resulting in increased number of components to operate).

Various LIPA substations were added or got redesigned to provide interconnection capability to various AC/DC tie lines, generation and reactive resources. The existing control center is facing the following challenges to accommodate and support these modifications:

1. Congestion and overcrowding of existing system big board used to display and provide status of the transmission system.
2. Lack of dynamic displays affecting visibility, efficiency and increased potential for human errors.
3. Lack of space to introduce tools to enhance situational awareness.

A new control center is required as a resolution.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0349 Supplemental
Date of Response: 05/07/2015
Witness: N/A
We need to attach Robert Lamb's July 2014 study proposal.

Question:

349. In Exhibit-CBP-2, the proposed budgets for the above project are $5M in 2016, $25M in 2017, and $20M in 2018.

a. Provide a detailed cost breakdown of the proposed budgets in each rate year from 2016 to 2018. The cost breakdown should be included, but not limited to labor, materials, overhead, contingencies, and/or other indirect costs.

b. Provide the current project status of the first phase, including the amount spent on the project to-date.

c. Provide any internal justification documents that the Company has submitted to senior management beyond the PJD.

d. Fully explain why the current control room in Hicksville cannot be expanded to another adjoining room or done through a building expansion.

Attachments Provided Herewith: 1
DPS-CBP_0349 Supplemental_Robert Lamb Proposal.Redacted.pdf

Response:

This response supplements PSEG LI's response to DPS-CBP-349.

a. Supplemental Response:
The preliminary rate period estimates that were set forth in Exhibit __ (CBP-2) for the Transmission System Operations Control Center have been updated in PSEG LI's response to Discovery Request DPS-CBP-434. This project is now planned to commence in 2017 and take approximately three years to complete.

b. Supplemental Response:
Please see part a.

c. Supplemental Response
None. See original response.

d. Supplemental Response:

PSEG LI currently operates a Transmission Control Room with a lighted map-board wrapping around two sides of the room, three switching desks for district operators, positions for additional operators/managers, and miscellaneous individual flat panels for displaying real-time information. Constraints such as shape of the room, location of the room within the facility, and limited ceiling height limit the potential options for inclusion of new technology and future expansion of the operations.

Several new transmission substations and circuits have been added over time and more are currently being added to the LIPA system. Several existing substations were reconfigured or are in the process of redesign to increase reliability (resulting in increased number of components to operate). Various LIPA substations were added or redesigned to provide interconnection capability to various AC/DC tie lines and generation and reactive resources.

The existing control center is facing the following challenges to accommodate and support these modifications:

1. Congestion and overcrowding of the existing system board used to display and provide status of the transmission system.

2. Lack of dynamic displays affecting visibility, efficiency and increased potential for human errors.

3. Lack of space to introduce tools to enhance situational awareness.

4. Board congestion is leading to a human factors concern.
   A new control center is required as a resolution.

PSEG LI has retained the firm of Robert Lamb. This firm has completed over 250 Control Room projects in the U.S. and Canada over the past 45 years that are similar to the LIPA control center project. Robert Lamb's in-house team includes Architects and Structural, Mechanical, and Electrical Engineers, as well as Construction / Estimating professionals. The firm's proven approach to similar High Reliability, Critical Infrastructure, and NERC/CIP compliant projects has made them a leader in the industry.

As requested by DPS staff, Robert Lamb's July 2014 study proposal is being provided. Because it contains confidential pricing information, we are providing the proposal to the DPS Records Access Officer with a request for confidential treatment.

The potential vendor/contractor that is selected would perform a planning study to confirm the actual schedule and cost breakdown.

Based on past experience, Robert Lamb indicated that a new Control Center Facility, built up to the industry best practices for reliability, redundancy, and functionality, would fall between $550 and $650 per square foot. This does not include land acquisition costs, site improvements/land development, site utilities, or costs associated with relocation of services or project management.

The actual budget would be dependent on the type of site, and associated infrastructure availability.

It is expected that additional costs will be incurred to relocate the infrastructure associated with SCADA, Energy Management System and to meet NERC Critical Infrastructure Protection security requirements.

The facility is required to have a footprint that satisfies the above mentioned requirements. The existing National Grid-owned operations building has a footprint of 55,000 square feet. It is estimated that a facility with a similar footprint is required to support the functionality of the proposed control center and associated support staff and functions. The existing Control Room and surrounding facility offers limited room for improvement without substantial renovation. A planning study is required to firm up these requirements, associated costs and schedules. The proposed planning study would evaluate two options: renovating the existing location and building a new facility.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0372
Date of Response: 04/20/2015
Witness: CAPITAL BUDGETS

Question:
The exhibits of the Capital Budgets Panel contain information that does not appear to be consistent with information contained in the exhibits of the Ratemaking and Revenue Requirement Panel. In particular, the T&D Capital and Deferred expenditure costs included in Exhibit __(RRP-1), page 17 of 19, excluding FEMA Related Projects, do not appear to match the proposed Total T&D Budget amounts included in Exhibit __(CBP-2), page 4 of 4.

For each of three rate years:
a. Provide a detailed explanation as to why these amounts do not match.
b. Provide all work papers and reference material used to develop the Capital and Deferred Expenditure for T&D cost categories listed in Exhibit __(RRP-1), page 17 of 19.
c. For each specific or blanket T&D project listed in CBP-2, provide the estimated project start date, and estimated in service date. For blanket projects that are expected to enter service throughout each rate year, list as "ratably".

Attachments Provided Herewith: 1
Attachment with updated costs and dates.xlsx

Response:

A. The amounts shown on Exhibit ___ (CBP-2) for each of the rate case years (2016 – 2018) need to be increased by approximately 14.3% to align with the Proposed Budget Total with the A&G and Pensions/OPEB used in RRP-1. Additionally, changes have been made and continue to be made to the 2016 and later year projects as the budget review process continues. A revised Exhibit ___ (CBP-2) will be provided at a later date.

   The following revisions are required to Exhibit ___ (CBP-2):

   2016
   Distribution Automation funding is not required in 2016
   Shelter Island – New Distribution Sub project discussions are continuing with a placeholder value of $12 million which assumes we purchase land in proximity to existing transmission
   Barrett 4th Bank and feeders for a sewage plant is a reimbursable project
   Greenfield Land Purchase and Replace Existing banks – removed risk and contingency ("R&C")
   Hempstead Convert Sub from 23kV to 69kV – revised to reflect PJD estimate
   Riverhead – Eastport 69-951 Reconductor – revised to reflect PJD estimate
   New Cassel New Sub – removed R&C

Navy Rd (Montauk) new 23 – 13kV Sub – used PJD estimate

2017

Shelter Island – New Distribution Sub project discussions are continuing with a placeholder value of $8 million which assumes we purchase land in proximity to existing transmission.
Barrett 4th Bank and feeders for sewage plant is a reimbursable project
Old Bethpage – New Sub & Land Purchase – revised to reflect PJD estimate
Greenfield – removed R&C and revised cash flow
Hempstead Convert Sub from 23kV to 69kV – revised to reflect PJD estimate
New Cassel New Sub – removed R&C
Doctor's Path Riverhead – New Sub – placeholder project deferred one year
Navy Rd (Montauk) new 23 – 13kV Sub – revised to reflect PJD estimate
Buell Replace 20MVA 69kV-23kV Bank 1 with a 28MVA bank – deferred one year
Stewart Manor Switchgear Replacement – deferred one year
Amagansett Replace Existing Banks with 2 14MVA 23/33 13 kV Banks - revised to reflect PJD estimate

2018

Old Bethpage – New Sub & Land Purchase – revised to reflect PJD estimate
Greenfield – removed R&C and revised cash flow
New Cassel New Sub – removed R&C
Doctor's Path Riverhead – New Sub – placeholder project deferred one year
Nassau Hub New Sub – revised cash flow

Please refer to the attachment for updated cost estimates.

B. Workpapers have been submitted previously for RRP 1 page 17 of 19 and can be found in the files:

Excel File	**Tab Name**	**Description**
Amortization of ERP Costs	Amortization of ERP Costs	Amortization of Deferred Costs Associated with the ERP System
Constell NMP2 15-18 budgets 10-20-14	14-18@ 18% Schedule II to VI	Nine Mile Point 2 Budget
FEMA Cash Flow Forecast Rev7 3	Cash Flow Summary by Year	FEMA Cash Flow Forecast
Rate Case Data Deck no formulas.xlsx	4 Capital Primary View	Capital as budgeted in 1/5/15 in SAP
Base Case LIPA Debt Service.xlsx	CapEx	See Principal, Interest
Base Case LIPA Debt Service.xlsx	Overall	See Coverage
Figliozzi PGRR01 Revenue Requirement Model Set Final at 1 28 15.xlsx	Management Fee	
		See response to DPS-RRP-160-capitalized management fee

C. Please refer to the attachment for the start and end dates for the projects listed on Exhibit ___ (CBP-2).

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0420
Date of Response: 04/23/2015
Witness: CAPITAL BUDGETS

Question:
Reference PJD S16.1:
a. Provide a detailed explanation on the status of the land acquisition needed for this project.
b. Provide a one-line diagram or simple sketch for this project.
c. Describe to what extent this project corresponds with any other transmission projects included in any capital project(s) filed in the rates case? If yes, which project(s)?
d. Provide the load at risk and the hours of exposure for 2018, 2019, 2020, 2021 and 2022 if the proposed project is not built. Provide supporting studies to validate your answer.
e. Provide all engineering studies that justify this project.
f. Provide a Gantt chart which illustrates the project schedule. This chart should include, but not be limited to the project start date, project end date and major milestones.
g. Explain the variance between the cost shown on PJD S16.1 and the approximately cost for 2016 through 2018 shown on Exhibit CBP-2.
h. Provide a detailed cost breakdown for the proposed project including, but not limited to labor, materials, overhead, contingencies, and/or other indirect costs.
i. Provide in Excel with formulas intact, the benefit cost analysis that resulted in benefit cost ratios mentioned in the recommendation section of PJD S16.1.
j. Provide in Excel with formulas intact - calculations of figures referenced in the recommendation section of PJD S16.1.
k. Given that the proposed in-service date for the proposed Substation project, explain why Utility 2.0 options will be required to be in place in order to be considered as an alternative to the project.
l. Explain why planning for the recommended project cannot be done concurrently with evaluation of potential Utility 2.0 type alternative solutions.
m. Explain what the current plan is to seek Utility 2.0 type alternative solutions for this project.

Attachments Provided Herewith: 0

Response:

a) A parcel of land has been identified in the vicinity of Round Swamp Road and Old Country Road for a new substation site. PSEG LI Real Estate has made a verbal request to Nassau County to secure the property, and recently additional information on a plot drawing was requested by Nassau County.

b) This one-line was included in PSEG LI's response to DPS-CBP-404: The file name is S16.1 ONELINE_Old Bethpage_69kV_Install New Substation with Two 33MVA 69-13kV Banks_2018_Preliminary_R0_2014_10_22.CONFIDENTIALpdf. As noted in the PJD for this project, the name of the substation has changed over time as the potential locations were evaluated, for example, the names have included Old Bethpage, Canon and RXR.

c) This project will tie into the proposed project S1.1 Ruland to Planview – New Transmission Circuit, the route of which is proposed to be near the proposed substation. As such, the substation will need the transmission line to be in place to interconnect.

d) As noted in the PJD, this project is being proposed to address future load additions in the area. As such, the load at risk will depend on load development in the area which will also determine the timing of the substation. Potential major load increases in the area are described in a document that is being provided to the DPS Records Access Officer with a request for confidential treatment because it contains confidential customer information: Attachment_Load_Data_CONFIDENTIAL.

e) There is no engineering study justifying this project at this time as it is depended on the future load growth. At this time, PSEG-LI is working to procure land to ensure ability to install when needed.

f) This project has not proceeded to the point where this information has been developed. See also our response to DPS-CBP-404 which describes our capital process.

g) The estimates in the PJD were developed by Planning at a high level prior to inclusion in Exhibit __ (CPB-2) which spreads the dollars to the expected in-service date and includes risk and contingency dollars.

h) This project has not proceeded to the point where this information has been developed. See also response to DPS-CBP-404 which describes the capital process.

i) No spreadsheet was created at the time but rather done on a calculator. The PJD shows the two values that were used to generate the benefit cost ratio. For example, the initial Benefit cost ratio is 3MVA divided by $12 million to yield 0.25. When the 2nd bank is added the value increases to 4.0 based on 48 MVA divided by $12 million. Note response to question 384 included a sample spreadsheet for another project which shows division.

j) The following excel sheet is being provided to the DPS Records Access Officer with a request for confidential treatment because it contains Confidential Commercial Information:
RXR_oldbethpage_Cost_estimate_Analysis_2014_27_05_nick.CONFIDENTIAL.xls.
Note this spreadsheet is used to estimate project impacts when comparing alternatives. It is not meant to determine actual rates.

k) Given the large lump load and developments being added it is uncertain that Utility 2.0 will address the need as reinforcements to the site will still be required to connect the load. Adequate Utility 2.0 solutions would need to be in place with load reductions in order to evaluate other options and yet still allow for this project to proceed if needed.

l) Evaluation of Utility 2.0 options can be done concurrently with the project.

m) The current plan is to have the Energy Efficiency group evaluate this and all similar projects going forward as part of our proposed Utility 2.0 program.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0425
Date of Response: 04/24/2015
Witness: CAPITAL BUDGETS

Question:
Reference PJD S49.1:
a. Provide an explanation of how much load would potentially have to be shed under an N-1-1condition in 2016 and what are the hours of exposure.
b. Provide the load at risk and the hours of exposure for 2017, 2018, 2019, 2020, 2021 and 2022 if the proposed second circuit is not built.
c. Provide all engineering studies that support the need for the proposed second circuit.
d. Provide a Gantt chart which illustrates the proposed second circuit project schedule. This chart should include, but not be limited to the project start date, project end date and major milestones.
e. Exhibit CBP-2 shows the proposed capital expenditures for 2016, 2017 and 2018 for the proposed second circuit. What are the proposed capital expenditures for 2019, 2020 and 2021?
f. Provide a detailed cost breakdown for the proposed second circuit project including, but not limited to labor, materials, overhead, contingencies, and/or other indirect costs.

Attachments Provided Herewith: 0

Response:

a. See the document named "EGC-VS Confidential Response N-1-1 Contingency_CONFIDENTIAL." This document is being provided to the Records Access Officer because it contains confidential Critical Infrastructure Information ("CII").

b. The load at risk and the exposure hours for requested years if the proposed projects are not built are provided as a Load and Exposure Hour Table in the "EGC-VS Confidential Response N-1-1 Contingency_CONFIDENTIAL." This document contains CII and is being provided to the Records Access Officer. Please note that these numbers are preliminary and are subject to change depending on the outcome of detailed studies.

c. See "Barrett Area Limitation Chart-Confidential" document provided to the Records Access Officer because it contains CII. This document summarizes the preliminary study results and are subject to change based on ongoing detailed studies. See also PSEG LI's response to DPS-CBP-0247 where it refers to the"Preliminary NERC BES Gap Analysis" presentation.

d. This information is not available as project has not been approved by the Utility Review Board to commence any work including detailed engineering and scheduling.

e. These costs have not been defined for 2019, 2020 and 2021

f. Please refer to our response to DPS-CBP-404, Parts c and d.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0426
Date of Response: 04/24/2015
Witness: CAPITAL BUDGETS

Question:

a. Considering the cost effectiveness of distributed resources combined with load relief solutions , along with the ability of the REV solutions to achieve in-service dates necessary to support system reliability, how will that impact or determine the final recommendation to carry out this project (PJD S49.1).
b. Fully explain how the load relief requirement for this project was determined.
c. If cost effective REV solutions are obtained, will these solution obviate the need for the proposed project. If yes, for how long.
d. When will a decision be made to go forward with REV solutions. Provide the timing.

Attachments Provided Herewith: 0

Response:

g. See also response to DPS-CBP-0247. The final recommendation could defer the proposed Valley Stream-East Garden City transmission project provided that cost effective reliable solutions are in place by 2020 or earlier.

h. The magnitude of load relief required to defer the need for reinforcement is in the range of 100 to 200 MWs. These numbers are determined based on preliminary assumption of load relief based on resource additions in the Far Rockaway area. Note that the detailed studies will determine the actual load relief required to defer the need for reinforcements.

i. Yes; however, the time frame is dependent on the amount of load relief that is achievable for the area.

j. At this point timing is uncertain since the plan is to go out with a Request for Proposals to solicit REV solutions in the area. The decision will be based on the outcome of this RFP combined with the reliability and cost effectiveness of these possible solutions.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0428
Date of Response: 04/24/2015
Witness: CAPITAL BUDGETS

Question:
Reference PJD S50.1:
a. Describe the potential load shed under an N-1-1 condition in 2016 and what are the hours of exposure for each project
b. Provide the load at risk and the hours of exposure for 2017, 2018, 2019, 2020, 2021 and 2022 if proposed projects are not built.
c. Provide and explain the justification for proposed in-service dates outside of the three-year rate period as it applies to "alternatives" identified for each project.
d. Provide in Excel with formulas intact, the benefit cost analysis for these projects.
e. Provide all engineering studies for these projects.
f. Provide a Gantt chart which illustrates the proposed project schedule for the proposed projects. This chart should include, but not be limited to the project start date, project end date and major milestones.
g. Exhibit CBP-2 shows the proposed capital expenditures for 2016, 2017 and 2018 for the proposed projects. What are the proposed capital expenditures for 2019, 2020 and 2021?
h. Provide a detailed cost breakdown for the proposed project including, but not limited to labor, materials, overhead, contingencies, and/or other indirect costs.
i. Considering the cost effectiveness of distributed resources combined with load relief solutions, along with the ability of the REV solutions to achieve in-service dates necessary to support system reliability, how will that impact or determine the final recommendation to carry out each project
i. Fully explain how the estimated load relief requirement was determined.
ii. If cost effective REV solutions are obtained, will these solution obviate the need for the proposed projects? If yes, for how long.
iii. Provide for each project when a decision will be made to go forward with REV solutions. Provide the timing.

Attachments Provided Herewith: 0

Response:

k. See the document named "Confidential Response N-1-1 Contingencies_CONFIDENTIAL." It is being provided to the DPS Records Access Officer because it contains Critical Infrastructure Information ("CII").

l. As mentioned in the response to question (a), the load at risk and the exposure hours for requested years is not available at this time since detailed studies are underway to identify the magnitude of load loss and the corresponding exposure hours. Based on preliminary studies, the load risk is on the order of 100 MW to address N-1-1 contingencies. However this number is subject to change depending on the detailed study and optimization process to reduce the dependence on load loss.

m. As mentioned in the response to DPS-CBP-0154, a series of capital projects will be required to meet the newly applicable and expanded NERC Transmission Planning ("TPL") standards, including "TPL-001-4." Two capital projects have been identified to meet NERC TPL performance criteria for N-1-1 events, a new Syosset to Shore Road 138kV circuit and a new East Garden City to Valley Stream 138kV circuit. The effective date for TPL-001-4 standard was January 1, 2014, and as a result, projects to address N-1-1 criteria performance violations are required to be implemented by year 2020 if the first N-1 contingency is the loss of a generator. The project mentioned in PJD S50.1 is not driven by a generator contingency followed by another single contingency, but a line contingency followed by another line contingency. However, as stated in the NERC TPL standard, an objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. Further, the goal for system design is to not depend on load loss as a permanent design solution. The need date of 2020 was determined based on this reliability goal combined with the implementation time frame for a potential 138 kV solution that usually has an extended procurement and permitting process. It is noted that while these capital projects are being pursued, a Request for Proposals and Utility 2.0 alternative solutions are also under review, which may affect the need date for these projects.

n. See excel sheet titled "Economic- Syosset - Shore Road new 138kV circuit-CONFIDENTIAL" provided to the DPS Records Access Officer. Please note that the attachment is confidential due to commercially sensitive information.

o. See "Glenwood Area Limitation Chart – Confidential" that summarizes the preliminary study results. This document was provided to the Records Access Officer because it contains CII. Detailed studies are underway and additional study reports are not currently available other than the presentation that was provided as part of the response to DPS-CBP-0246.

p. This information is not available as project has not been approved by the Utility Review Board to commence any work including detailed engineering and scheduling.

q. These costs have not been defined for 2019, 2020 and 2021.

r. Please refer to PSEG LI's response to DPS-CBP-404, Parts c and d.

s. See also our response to DPS-CBP-0246. The final recommendation could defer the proposed transmission project, provided the cost effective reliable solutions are in place by 2020 or earlier.

i. The magnitude of load relief required to defer the need for reinforcement is in the range of 100 to 200 MWs. These numbers are determined based on preliminary assumption of load relief based on resource additions to the Northwest Nassau area. Note that the detailed studies will determine the actual load relief required to defer the need for reinforcements.

ii. Yes, the time frame is dependent on the amount of load relief that is achievable for the area.

iii. At this point timing is uncertain since the plan is to go out with a Request for Proposals to solicit REV solutions in the area. The decision will be based on the outcome of this RFP combined with the reliability and cost effectiveness of these potential solutions.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0443
Date of Response: 04/24/2015
Witness: CAPITAL BUDGETS

Question:
a. Provide a detailed explanation for the significant budget increase from costs in 2017 to the level of costs in year 2018 for the Substation Control and Protection Program found in Exhibit CBP-2 of the Capital Budget Testimony.

b. Provide a breakdown of the spending allocation for the "Substation Control and Protection Program" line item shown in Exhibit CBP-2 for calendar years 2016, 2017 and 2018 in terms of PJD references B32.2 through B32.19. The cost breakdown should include, but not be limited to labor, materials, overhead, contingencies, and other indirect costs.

Attachments Provided Herewith: 1
Substation Control and Protection 4-21-15.xlsx

Response:

A. The 2018 proposed budget contains a $7 million entry for a Relay Upgrades to Microprocessor Program. This is a placeholder for additional relay upgrades.

B. Please see the attached spreadsheet. Please note that a cost breakdown by labor, materials, overheads and other indirect costs is not available.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0446
Date of Response: 05/05/2015
Witness: CAPITAL BUDGETS

<u>Question</u>:
Provide the following information as requested including any related work papers:

1. In the response to DPS-CBP-0316 the company stated that for 2015, a $500,000 replacement program is currently underway for B30.4 - Multiple Interruptions - Hauppauge Industrial Area. Provide the justification for this program's budget to be escalated to $1 Million for the rate years 2016-2018 as proposed in the response to DPS-CBP-0314.
2. In PJD Reference 30.4 - 2014 Hauppauge Industrial Park Cable Replacements, the company states that :

"In 2012, 10000 ft of cable replacement is targeted and represents the 6th out of 10 years of funding for improvements committed by LIPA to this area."

If 2012 represents the 6th out of 10 years of funding to this area, then 2016 would represent the 10th year of funding. Provide the company's justification for continuing the funding of this program for 2017 and 2018 as proposed in the response to DPS-CBP-0314.

<u>Attachments Provided Herewith</u>: 0

<u>Response:</u>
The program detailed in these PJDs and the Company's funding program addresses replacing deteriorating steam cured PE and bared concentric neutral medium voltage cables. These cables are reaching the end of their useful life. Most major industrial parks on Long Island were developed during the 1970's and early 1980's. The medium voltage cable systems heavily used during that period utilized these types of cables which are now 30 to 40 years of age and their failure rates have increased significantly. The Hauppauge Industrial Area, which is the largest industrial area on Long Island, was the first of the major industrial parks to be addressed under this replacement program. While the original 10 year cable replacement program at the Hauppauge Park did achieve the goal of reducing the number of cable faults experienced on an annual basis, the 10-year replacement program was not designed to replace 100% of the cable in the park and further funding is anticipated as other sections experience high failure rates.

Other areas such as the Heartland Industrial area also need to be addressed as the cable in these areas is now older and needs to be addressed more quickly.

The increased funding requested will allow further upgrades within Hauppauge Park as well as other industrial parks on Long Island.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-CBP-0448
Date of Response: 05/05/2015
Witness: CAPITAL BUDGETS

Question:
Questions a through c refers to the Company's response DPS-Preliminary-0048 Supplemental:
a. For each year 2010 through 2014, indicate whether the Total Budget and Total Spending amounts provided were loaded for A&G and Pension/OPEB.
b. If the amounts indicated in response to question (a) above were loaded for A&G and Pension/OPEB, provide the amounts without loading.
c. If the amounts indicated in response to question (a) above were not loaded for A&G and Pension/OPEB, provide the amounts with loading.

Attachments Provided Herewith: 0

Response:

a. PSEG LI has requested 2010 – 2013 information from National Grid. The capital plan for 2014 did not include loadings for OPEBS and Pensions. The total amount loaded to capital projects for 2014 was as follows:
   Pension – $4,821,414
   FAS112 – $18,386,176
b. Because the 2014 budget was prepared using the National Grid system, it is not possible to determine clearing amounts for individual projects, although the overall clearing amounts can be determined. Information regarding clearing amounts for individual projects has been requested from National Grid.
c. The 2014 Capital Budget and Actual can be found in DPS 0048 Supplemental.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: DPS-PRELIMINARY-0048
Date of Response: 03/13/2015
Witness: CAPITAL BUDGETS

Question:
Provide actual and budgeted capital expenditure amounts for the last five historic years, in aggregate and by specific blanket grouping or project. Budgeted expenditure levels should be the levels approved by the company's Board of Trustee's for each historic period.

Attachments Provided Herewith: 2
DPS-PRELIMINARY_0048_December 2014 Final YE Variance run 01-14-15.pdf
DPS-PRELIMINARY_0048_December 2014 - rptCurrentVSLastYearBreakdown.pdf

Response:
PSEGLI's 2014 actual and budgeted capital expenditure amounts by project are attached. The cost summary was also provided by month in DPS-Preliminary-0064. PSEG LI does not have access to prior year data.

PSEG Long Isand Capital Budget and Staff Adjustments

TOTAL BUDGET	Construction Expenditure Estimates		
	2016	2017	2018
Company original CBP-2	$350,242,415	$371,149,078	$370,458,016
Company's response to 372 with project adjustments *including* A&G and pension/OPEB loadings	$360,853,190	$336,597,016	$381,957,754
Percent A&G/Pensions/OPEB loading	14.3%	15.6%	16.5%
Company's response to 372 with project adjustments *excluding* A&G/ pension/OPEB loadings	$315,707,078	$291,173,889	$327,860,733
Staff Adjustment for Blankets	($1,831,200)	($1,885,936)	($15,663,706)
Staff Adjustment-Old Bethpage Substation			($13,000,000)
Staff Adjustment-Specific Projects for Substation Reliability Enhancements Program			$4,519,091
Total Staff Recommended Budget	$313,875,878	$289,287,953	$303,716,118

BLANKET ACCOUNTS	Construction Expenditure Estimates		
	2016	2017	2018
Company's response to 372 with Blanket account adjustments *excluding* A&G/ pension/OPEB loadings	$140,442,903	$149,702,228	$166,096,768
Staff Adjustment-New Business	($1,831,200)	($1,885,936)	($1,944,615)
Staff Adjustment-Substation Reliability Enhancements Program			($4,519,091)
Staff Adjustment-Multiple Interruptions			($2,200,000)
Staff Adjustment-Substation Control & Protection Improvements			($7,000,000)
Staff Adjustment for Blankets	($1,831,200)	($1,885,936)	($15,663,706)
Staff Recommended budget for Blanket Projects	$138,611,703	$147,816,292	$150,433,062