STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE VERIFIED PETITION OF PUBLIC SERVICE ELECTRIC & GAS FOR APPROVAL OF AN INFRASTRUCTURE INVESTMENT PROGRAM (PSE&G ENERGY STRONG II)	**)))))))))))**	**BPU DOCKET NO. EO18060629 and GO18060630**

DIRECT TESTIMONY OF CHARLES SALAMONE
AND MAXIMILIAN CHANG
ON BEHALF OF DIVISION OF RATE COUNSEL

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Attachment RC-ENG-1
Attachment RC-ENG-2

I. STATEMENT OF QUALIFICATIONS

Q. Would the members of the Engineering Panel Review ("Panel") please state your names, positions, and business address.

A. My name is Charles Salamone, PE. I am Owner of Cape Power Systems Consulting, LLC a power systems consulting Company with an address of 630 Cumberland Dr., Flagler Beach, Florida and I am a subcontractor of Synapse Energy Economics, Inc. ("Synapse").

My name is Maximilian Chang. I am a Principal Associate with Synapse Energy Economics, an energy consulting company located at 485 Massachusetts Avenue, Cambridge, Massachusetts.

Q. On whose behalf are you submitting testimony in this proceeding?

A. We are submitting testimony on behalf of the New Jersey Division of Rate Counsel ("Rate Counsel").

Q. Mr. Salamone, please describe your education and professional background.

A. I hold a Bachelor of Science Degree in Electrical Engineering from Gannon University. I joined the Engineering Department of Commonwealth Electric Company in 1973. At that time, I became a Junior Planning Engineer where my primary responsibilities were to assist in the planning, analysis, and design of the transmission and distribution systems of Commonwealth Electric Company, later known as NSTAR. I generally followed the normal progression of positions with increasing levels of responsibility within the planning area until taking the position of Director of System Planning at NSTAR in 2000. I held that position until starting Cape Power Systems Consulting, LLC in 2005. During my career with NSTAR, in addition to the responsibilities associated with overseeing System Planning, I served as Chair of the New England Power Pool ("NEPOOL") Planning Policy Subcommittee (1997-1998), Chair of the NEPOOL Regional Transmission Planning Committee (1998-1999), and Vice Chair of the NEPOOL Reliability Committee (1999-2000). As a consultant, I have been providing consulting services to a number of power system industry clients since 2005. I am a Registered Professional Engineer with the Commonwealth of Massachusetts. I am also a senior member of the Power Engineering Society of the Institute of Electrical and Electronic Engineers. A copy of my resume is attached as **Attachment RC-ENG-1**.

Q. Mr. Salamone, have you previously testified before utility regulatory agencies?

A. Yes. I have previously testified before the New Jersey Board of Public Utilities ("BPU" or "Board"), the Federal Energy Regulatory Commission ("FERC"), the Massachusetts Department of Public Utilities, and the Massachusetts Energy Facilities Siting Board on a number of technical matters relating to ratemaking and system planning. In addition, I have filed testimony in other similar infrastructure dockets within New Jersey: Docket EO13020155 and GO13020156 (Energy Strong), Docket EO18020196 (ACE Infrastructure Investment Program), and Docket EO18070728 (JCP&L Infrastructure Investment Program).

Q. Mr. Chang, please describe your professional background at Synapse Energy Economics.

A. My experience is summarized in my resume, which is attached as **Attachment RC-ENG-2**. I am an environmental engineer and energy economics analyst who has analyzed energy industry issues for ten years. In my current position at Synapse Energy Economics, I focus on economic and technical analysis of many aspects of the electric power industry, including: (1) utility mergers and acquisitions, (2) utility reliability performance and distribution investments, (3) nuclear power, (4) wholesale and retail electricity markets, and (5) energy efficiency and demand response alternatives. I have been an author and project coordinator for the last two biennial New England Avoided Energy Supply Component reports, which were used by energy efficiency program administrators in the six New England states to evaluate energy efficiency programs.

Q. Mr. Chang, please describe your educational background.

A. I hold a Master of Science degree from the Harvard School of Public Health in Environmental Health and Engineering Studies, and a Bachelor of Science degree from Cornell University in Biology and Classical Civilizations.

Q. Mr. Chang, have you previously submitted testimony before the Board of Public Utilities?

A. Yes. I filed testimony before the Board in dockets GO12050363 (South Jersey Gas Energy Efficiency), EM14060581 (Exelon-PHI Merger), ER14030250 (RECO Storm Resiliency), GM15101196 (AGL Southern Company Merger), ER17030308 (ACE Rate Case), ER18010029 (PSE&G Rate Case), and EO18020196 (ACE Infrastructure Investment Program), and EO18070728 (JCP&L Infrastructure Investment Program).

Q. Mr. Chang, have you previously testified before utility regulatory agencies?

A. Yes. I have previously testified before the District of Columbia Public Service Commission, the Hawaii Public Utilities Commission, the Illinois Property Tax Appeal Board, the Maine Public Utilities Commission, the Maryland Public Service Commission, and the Massachusetts Department of Public Utilities. I have also filed testimony before the Delaware Public Utilities Commission, the Kansas Commerce Corporation, the Illinois Commerce Commission, and the United States District Court for the District of Maine.

II. PURPOSE AND SUMMARY OF RECOMMENDATIONS

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to review aspects of Public Service Electric and Gas' (the "Company" or "PSE&G") petition ("Petition") to seek approval from the New Jersey Board of Public Utilities (the "Board") for the implementation of its Energy Strong II Infrastructure Investment Program ("Energy Strong II"). As filed, the Energy Strong II spending proposal amounts to $1.503 billion for electric projects from 2019 to 2023.

Q. Please summarize your findings and recommendations.

A. We find and conclude the following:

- The majority of the proposed electric programs are the continuation of programs already undertaken by the Company to maintain safe and reliable service and therefore should not receive accelerated recovery.
- The Company's own cost-benefit analysis shows that the $906 million Substation subprogram is not cost-effective under the Company's base case and Hurricane Sandy sensitivity case.
- The $478 million Substation Upgrade 26/ 4 kilovolt (kV) subprogram is not supported by detailed engineering reports for each of the projects as required under N.J.A.C 14:3-2A.5(b)(3). The Company only provided broad outlines of programs and does not provide individual project completion dates for this subprogram since the detailed engineering analysis has not been completed.
- The Company purports that its $375 million spacer cable and $45 million reclosing device subprograms will help reduce outages associated with tree damage during storm events. The Company has yet to complete a trimming cycle under the Board's 2016 vegetation management regulations for additional trimming of circuits. Therefore, the Board should wait until the completion of a trimming cycle to determine the appropriateness of subprograms meant to mitigate tree-related outages.
- We recommend that the Board require that the Company use its five-year historical average of $223.6 million for annual baseline electric capital spending.

- If the Board were to proceed with approval of PSE&G's Energy Strong II, notwithstanding the identified deficiencies, we recommend that it only approve a five-year program with a $107 million budget subject to the submittal of detailed engineering reports for the Energy Strong II program. The $107 million budget reflects our recommended adjustments to the Company's proposal. We recommend including the Company's Grid Modernization subprogram which includes Advanced Distribution Management ($35 million) and Communication Network programs ($72 million).

III. ENERGY STRONG I

Q. Please summarize your understanding of the Company's 2014 Energy Strong I Program.

A. The Company's Energy Strong I program provides important context to our positions in this proceeding. The Energy Strong I proceeding provided a regulatory cost recovery mechanism for the Company to undertake $600 million of capital investments to improve the resiliency of the Company's electric distribution system following the impacts from Hurricane Irene, the October 2011 Snowstorm, and Superstorm Sandy. In addition, the Board's stipulation allowed the Company to make an additional investment of $220 million for the substation investment program that would be recovered in base rates.[1] The Company's Energy Strong I investments are summarized below:

Schedule 1 PSE&G Energy Strong I Stipulated and Actual Spending[2]

Program	Stipulated Amount (millions)	Amount Spent (millions)
Substation Flood Mitigation	$400	$422.9
Contingency Reconfiguration	$100	$93.6
Advanced Technologies	$100	$106.2
Total	$600	$622.7
Notes The Substation Flood Mitigation subtotal excludes the $220 million of substation investments not part of the Energy Strong I cost recovery mechanism.		

The approved settlement allowed the Company to rehabilitate the 26 substations damaged by either Hurricane Irene and/or Superstorm Sandy.[3] In addition, the Settlement allowed for the investment of $100 million for the Company's Contingency Reconfiguration program**.** This program focused on improving the resiliency of 262 critical facilities (e.g., hospitals, police stations, senior centers, water treatment facilities, and FBI communications tower) by increasing sectionalization and alternative ties on selected circuits. [4] Specifically, the program focused on creating multiple sections, utilizing smart switches, smart fuses, and adding redundancy within its loop scheme. The Company noted that by

[1] BPU. *Order Approving Stipulation of Settlement.* May 21 2014. Docket EO13020155 and GO13020156. Page 5.
[2] Pegasus Global Holdings, Inc. *Energy Strong Program Independent Monitor 2018 Second Quarter Report- Public Version.* September 14, 2018. Page 5 (RCR-ENG-E-0005)
[3] During the implementation of the Energy Strong I program, the Company removed the Madison and Marshall substations from the project list.
[4] Pegasus Global Holdings, Inc. *Energy Strong Program Independent Monitor 2016 Annual Report- Public Version.* May 3, 2017. Page 57.

having more sections in loop schemes and/or more circuit ties, fewer customers would be interrupted when damage occurs in a specific section of the loop. The Company ultimately spent $93 million of the approved $100 million for this project because in the fall of 2016 the Company determined that it could complete its proposed scope of work on the 262 facilities for less than the stipulated amount. The Company transferred ultimately $6 million from the subprogram to the Advanced Technologies subprogram.[5]

The final part of the Energy Strong I program was $100 million for Advanced Technologies. This program improved monitoring and visibility of the Company's electric distribution system by equipping 111 substations with 1,176 relays and 51 remote terminal units that expanded SCADA visibility.[6] The Advanced Technology program intended to shorten storm restoration processes with respect to damage assessment and efficiency of storm restoration work for the Company. Installation of Microprocessor Relays and expanded SCADA also enhanced the availability of operational information of the Company's electric distribution system. The Company spent $106 million of the $100 million in the program.

[5] Pegasus Global Holdings, Inc. *Energy Strong Program Independent Monitor 2016 Annual Report- Public Version.* May 3, 2017. Page 4.
[6] Pegasus Global Holdings, Inc. *Energy Strong Program Independent Monitor 2017 Annual Report- Public Version.* April 11, 2018. Page 4.

Q. Has the Company completed most of the program?

A. For the most part. We understand that only one substation still remains in construction, but the work is anticipated to be completed by the second quarter of 2019.[7]

Q. What is the importance of the Energy Strong I settlement to this proceeding.

A. The Energy Strong I program addressed the immediate need to rehabilitate and harden substations and facilities impacted by major storm events. In this proceeding the Company has proposed to implement an Energy Strong II program pursuant to the Board's Infrastructure Investment Program ("IIP") regulations for utility plant that was not damaged by Superstorm Sandy nor Hurricane Irene.

IV. INFRASTRUCTURE INVESTMENT PROGRAM REGULATION

Q. What is your understanding of the Infrastructure Investment Program Regulation within New Jersey?

A. It is our understanding that in 2018, the Board adopted the Infrastructure Investment Program Regulations ("IIP Regulations") to support accelerated distribution investments that go above and beyond "business as usual" distribution system spending.[8] In broad terms, the Board has indicated that qualifying projects would be eligible for accelerated cost recovery and must enhance the reliability, safety, and/or resiliency of the grid.[9] The IIP Regulations do not supplant an

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[7] Pegasus Global Holdings, Inc. *Energy Strong Program Independent Monitor 2018 Second Quarter Report- Public Version.* September 14, 2018. Page 23.
[8] N.J.A.C 14:3-2A.1(a).
[9] N.J.A.C 14:3-2A.1(a).

electric distribution company's (EDC) responsibility to maintain adequate spending for normal distribution operations.

Q. Would this make any project eligible under the IIP Regulations?

A. No, the IIP Regulations "encourage[s] and supports necessary accelerated construction, installation, and rehabilitation of certain utility plant and equipment."[10] We believe that the IIP Regulations are intended for certain types of investments that would not likely occur at this time without an accelerated cost recovery mechanism. Additionally, the Board's IIP Regulations clearly state that qualifying investments must be well supported as per the Board's minimum filing requirements in the form of engineering evaluations and cost-benefit analyses justifying both their cost effectiveness and impact on the reliability and resiliency goals as established by the Board.[11] If the projects are deemed eligible and they meet the requirements set forth in the IIP Regulations, once approved by the Board, the IIP mechanism would allow the utility to accelerate these qualifying capital investments and obtain accelerated recovery for these investments.

Q. As defined by the Board, what projects are eligible for accelerated cost recovery under the IIP Regulations?

A. Projects eligible under the accelerated cost recovery mechanism as established by the IIP Regulations must enhance safety, reliability, and/or resiliency and must be non-revenue producing.[12] It is our understanding that program eligibility must be

[10] N.J.A.C. 14:3-2A.1(b).
[11] N.J.A.C. 14:3-2A.5(b)(3).
[12] N.J.A.C. 14:3-2A.1(a).

supported by engineering evaluations and cost-benefit analyses provided by the utility.[13] Also, the projects eligible under the IIP must be incremental to the annual baseline spending levels established by the Board.[14]

Q. Please describe additional eligibility requirements of the regulation.

A. Another critical eligibility criterion of the IIP Regulations is the Board's requirement that:

> Only expenditures that are in excess of the annual baseline spending levels established by the Board and that meet the other requirements of this subchapter shall be eligible for accelerated recovery pursuant to N.J.A.C. 14:3-2A.6.

We believe that the Board incorporated this provision to ensure that eligible programs would not replace or supplant the Company's normal distribution spending to provide safe and reliable service to customers. Consequently, we do not think that the Board intended the Company to reduce baseline distribution infrastructure budgets and to shift normal reliability projects to the proposed infrastructure investment program.

Q. How do the IIP Regulations tie to the proposed Energy Strong II program?

A. The Company indicates the Energy Strong II program is "consistent with the IIP regulations."[15] And the Company notes, "Appendix 1 attached to this Petition sets forth the location in this filing of all requirements per the Board's IIP

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[13] N.J.A.C. 14:3-2A.5(b).
[14] N.J.A.C. 14:3-2A.3(d).
[15] Petition. June 8, 2018. Page 2.

regulations."[16] Thus, we review this Petition consistent with our interpretation of the Board's IIP regulations.

V. PSE&G INFRASTRUCTURE INVESTMENT PROGRAM

Q. Please summarize the Company's proposed Energy Strong II spending.

A. The Company is seeking Board approval to spend $1.503 billion between 2019 through 2023 for its Energy Strong II program. PSE&G Witness Edward Grey's direct testimony provides a summary of the Company's proposed Energy Strong II capital spending between 2019 and 2023. We have provided a tabular representation of the capital spending below:

[16] Petition. June 8, 2018. Page 2.

Schedule 2 Proposed PSE&G Energy Strong II Electric Program Budget for 2019-2023[17]

Program	Subprogram	Petition (thousands)
Substation	Station Flood and Storm Surge Mitigation	$428,000
	Substation Upgrades 26/4kV Stations	$478,000
Outside Plant, Higher Design and Construction Standards	Spacer Cable	$345,000
Contingency Reconfiguration Strategies	Increased Sectionalization	$100,000
	Reclosing Devices	$45,000
Grid Modernization	Advanced Distribution Management System	$35,000
	Communications Network	$72,000
Total		**$1,503,000**

The Company's proposed electric Energy Strong II spending is concentrated in four program categories detailed below:

1. **<u>Substation Program</u>**: This program is divided into two subprograms: (a) Station Flood and Storm Surge Mitigation; and (b) Life Cycle Station Replacement

a. <u>Station Flood and Storm Surge Mitigation</u>

The Company will rebuild assets for sixteen substations that have components below the established local flood elevation requirements adopted by the Company following Superstorm Sandy.[18] The sixteen identified substations will either be eliminated or raised by one foot above the FEMA's 100-year flood elevation.[19]

[17] Attachment 5, Schedule- BV-ESII-ELEC-4, Page 8 of 119 and Appendix I, Page 114 of 119
[18] Direct Testimony of Edward Gray. June 8, 2018. Page 14, lines 19.
[19] Direct Testimony of Edward Gray. June 8, 2018. Page 14, lines 20.

None of the sixteen substations experienced major flooding events.[20] For the station flood and storm surge mitigation program, the Company is proposing to spend $428 million on this subprogram over the five-year period. The following provides details for the sixteen substations:

Schedule 3 Substation Flood and Storm Surge Mitigation Subprogram Details
[Begin PSE&G Confidential]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		

[End PSE&G Confidential]

[20] RCR-ENG-E-0011

The average age of the substations is approximately 65 years. The Company has acknowledged that 11 of the substations in the subprogram also fit under the Substation Upgrades 26/4 kV subprogram.[21] The Company's cost estimates include risk and contingency estimates. Depending on the project, these range from **[Begin PSE&G Confidential]** [redacted]. **[End PSE&G Confidential]** The vast majority of the substations in the subprogram have a risk and continency value of **[Begin PSE&G Confidential]** [redacted] **[End PSE&G Confidential]** percent or office level estimates.[22]

b. <u>Substation Upgrades 26/4 kV Stations</u>

The Company also proposes programmatic replacement of aged substation facilities. The company has identified 15 substations that have the highest risk based on Black and Veatch's Asset Risk Model.[23] The Company touts that this initiative will avoid the safety, reliability, and ongoing operation costs of the substations that the Company has identified to be at or near the end-of-life.[24] As noted above, the Company included 11 substations in the Substation Flood and Storm Surge Mitigation subprogram as well. The Company proposes to spend approximately $478 million on aged substations over the five-year life of the program. As part of its petition, the Company provides a generalized engineering

[21] Direct Testimony of Edward Gray. June 8, 2018. Page 15, lines 11 and 12.
[22] Schedules EFG-ESII-4 Confidential.
[23] Direct Testimony of Edward Grey. June 8, 2018. Page 15, lines 3-6.
[24] Direct Testimony of Edward Grey. June 8, 2018. Page 10, line 7.

report for the class of substations.[25] All of the substations in the subprogram have a risk and continency value of **[Begin PSE&G Confidential]** [redacted] **[End PSE&G Confidential]** percent or office level estimates.[26]

2. **<u>Outside Plant, Higher Design and Construction Standards</u>:** This program consists of one subprogram: Spacer Cable. The Spacer Cable subprogram would convert existing cross-arm open wire construction 13kV and 4kV circuits to compact spacer cable on circuits.[27] The spacer cable system is composed of weather-proof wire compacted into a bundle with steel cable support in contrast to wood crossarms on utility poles.[28] The cabling enables the wire to better withstand tree and branch contacts. The subprogram would affect approximately 450-500 miles of circuits during the first five years and replace 7,100 poles with additional storm guying.[29] The Company proposes to spend $345 million over the five-year life of the program.

3. **<u>Contingency Reconfiguration Strategies:</u>** This program is divided into two subprograms: (a) Increased Sectionalization and (b) Reclosing Devices.

a. <u>Increased Sectionalization</u>

The proposed Increased Sectionalization subprogram would include three parts: (1) Convert all existing two section overhead 13kV circuits to three section circuits. (2) Enhance ~500 overhead 4 kV radial circuits with reclosers to create two sections. (3) Replace ~100 three-phase branches with and without fuses with

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[25] Schedule EFG-ESII-5 Confidential.
[26] Schedules EFG-ESII-5 Confidential.
[27] Direct Testimony of Edward Grey. June 8, 2018. Page 22, line 5.
[28] https://www.marmonutility.com/AerialCableSystems.aspx
[29] Direct Testimony of Edward Grey. June 8, 2018. Page 23, line 6.

branch reclosers. The Company proposes to spend $100 million for this subprogram during the five-year period of the IIP.

b. Reclosing Devices

The Company proposes to install automatic single-phase reclosing devices in line with fuses on single- and two-phase branch lines that currently have only fuses installed.[30] The Company plans to install approximately 3,200 reclosers.[31] Over the five-year period of Energy Strong II, the Company proposes to spend $45 million for this subprogram.

4. **Grid Modernization Subprogram:** This program is divided into two subprograms: (a) Advanced Distribution Management System (ADMS) and (b) Communications Network.

a. Advanced Distribution Management System

The proposed Advanced Distribution Management System subprogram would build a centralized SCADA system and implement ADMS to manage the electric distribution network in real time.[32] The Company proposes to spend $35 million for this subprogram during the five-year period of the IIP to replace its current 18-year old outage management system.[33]

b. Communications Network

The proposed communications subprogram would replace the existing dedicated telecommunication circuits across the Company's service territory with the high -

[30] Direct Testimony of Edward Grey. June 8, 2018. Page 27, line 17.
[31] Attachment 5 Schedule-BV-ESII-ELEC-4 (page 13 of 119).
[32] Direct Testimony of Edward Grey. June 8, 2018. Page 30, lines 8-13.
[33] RCR-ENG-E-0030

speed wireless mesh network.[34] The Company claims that the network will connect reclosers and new reclosing devices to new and existing fiber optic cable infrastructure at PSE&G substations.[35] The Company proposes to spend $72 million for this subprogram during the five-year period of the IIP.

VI. MINIMUM FILING REQUIREMENTS FOR IIP PROGRAMS

Q. Do the IIP Regulations mandate minimum filing requirements for IIP petitions?

A. Yes. As detailed in N.J.A.C. 14:3 2A.5(c), the Board may require additional information, beyond the information required that the Board deems necessary to evaluate the utility's petition in support of an IIP. The minimum filing requirements to be filed as part of an IIP petition under N.J.A.C. 14:3 2A.5(b) include:

1. Projected annual capital expenditure budgets for a five-year period, identified by major categories of expenditures;
2. Actual annual capital expenditures for the previous five years, identified by major categories of expenditures;
3. An engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives-including the specific expected resilience benefits, detailed cost estimates, in service dates, and any applicable cost-benefit analysis for each project;
4. An Infrastructure Investment Program budget setting forth annual budget expenditures;
5. A proposal addressing when the utility intends to file its next base rate case, consistent with N.J.A.C. 14:3-2A.6(f);
6. Proposed annual baseline spending levels, consistent with N.J.A.C. 14:3-2A.3(a) and (b);
7. The maximum dollar amount, in aggregate, the utility seeks to recover through the Infrastructure Investment Program; and

[34] Direct Testimony of Edward Grey. June 8, 2018. Page 32, lines 3-5.
[35] Direct Testimony of Edward Grey. June 8, 2018. Page 33, lines 8-13.

8. The estimated rate impact of the proposed Infrastructure Investment Program on customers.[36]

The Company's Petition would thus need to conform to these requirements for the Board to consider the eligibility of PSE&G's Energy Strong II projects.

Q. Did PSE&G's Energy Strong II petition meet the minimum filing requirements as required by the Board?

A. The Company's petition did not include the following items:

- Detailed engineering reports for the $478 million Substation Upgrade 26/4 kV subprogram.
- Detailed timing and unit costs for the $345 million Spacer Installation subprogram.
- Detailed timing and unit costs for the $100 million Increased Sectionalization subprogram.

Q. What would an appropriate engineering report look like?

A. N.J.A.C. 14:3-2A.5(b)(3) described the content of an accompanying engineering evaluation and report that would be part of an IIP petition. Specifically, the language of the Regulation states:

> An engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives-including the specific expected resilience benefits, detailed cost estimates, in service dates, and any applicable cost-benefit analysis for each project.[37]

[36] N.J.A.C. 14:3-2A.5(b)
[37] N.J.A.C. 14:3-2A.5(b)(3).

We identify several areas that were lacking as described below:

Identify Specific Projects: Merely listing the project names and locations for Substation Upgrade does not provide the information necessary to evaluate the justification and/or analysis in support of a project. The Company did provide a generalized engineering report for the substation upgrade program as part of its petition. However, the generalized report does not address site specific conditions that would be expected in a substation-specific report. The Spacer Cable, Increased Sectionalization, and recloser subprograms are blanket programs and thus also lack specific detail.

Alternatives Analysis: For the Substation Flood and Storm Surge Mitigation subprogram analysis, the Company's engineering reports **[Begin PSE&G Confidential]** [redacted] **[End PSE&G Confidential]** for each substation under this subprogram.

Detailed Project Costs/Timelines: The Company did not provide individual project costs for the Spacer Cable and Increased Sectionalization subprograms. For example, the Company did not provide individual project costs for the subprogram for any of the five years. The Company has not provided detailed timelines for the $478 million Substation Lifecycle subprogram because the Company has not yet completed the detailed engineering analyses.[38]

[38] RCR-ENG-E-0012.

Q. Why is a complete engineering analysis important?

A. We believe that a complete engineering report is critical to evaluate the IIP program because it provides the basis for the justification and prioritization of any proposed IIP projects. A complete engineering report also provides documentation of the baseline assumption, timing, and costs of the projects. Furthermore, this information will be critical at the close-out of the program to determine if the Company accomplished what it proposed at the outset of the IIP program.

VII. HISTORICAL ELECTRIC DISTRIBUTION CAPITAL SPENDING TO ESTABLISH BASELINE SPENDING

Q. Please summarize your recommendations regarding the Company's proposed baseline spending.

A. We find that the Company's projected average Total Distribution base capital spending for 2019-2023 period is $233 million, compared to its historical average total distribution spending (2013-2017) which is $223.6 million.[39] The Company's projected Total Distribution spending appears to be consistent with historical Total Distribution spending. However, the Company's proposed $233 million baseline spending also includes Energy Strong II like work that overstates the actual baseline spending. Therefore, we recommend that the annual baseline spending levels should be established based on the Company's five-year historical average baseline spending, which is $223.6 million.

[39] RCR-ENG-E-0001

Q. Does the Regulation establish baseline spending requirements?

A. The IIP Regulations require the establishment of baseline spending levels under N.J.A.C. 14:3-2A.3(b) and require infrastructure program spending to be incremental to baseline spending in N.J.A.C. 14:3-2A.3 (d). The language of N.J.A.C. 14:3-2A.3(b) lists a number of items which might be relevant to base line spending levels:

> In proposing annual baseline spending levels, the utility shall provide appropriate data to justify the proposed annual baseline spending levels, which may include historical capital expenditure budgets, projected capital expenditure budgets, depreciation expenses, and/or any other data relevant to the utility's proposed baseline spending level.

Additionally, the language of N.J.A.C. 14:3-2A.3(d) states:

> Only expenditures that are in excess of the annual baseline spending levels established by the Board and that meet the other requirements of this subchapter shall be eligible for accelerated recovery pursuant to N.J.A.C. 14:3-2A.6.

The Company's proposed Total Distribution Capital budgets presented in Schedule DP-2 appear to be consistent with the Board's IIP Regulations.

Q. Does the Company provide a summary of historical electric baseline spending in its Petition?

A. Yes, PSE&G's response to RCR-ENG-E-0001 provides a summary of the Company's historical capital spending through 2017. The Company's overall distribution capital spending is presented below.

Schedule 4 PSE&G Historical Electric Distribution Capital Spending ($ millions)[40]

Program	2013	2014	2015	2016	2017
Replace Facilities	$113.1	$104.0	$101.0	$123.0	$172.0
System Reinforcement	$43.6	$34.6	$55.5	$74.3	$146.8
Environmental Regulatory	$9.7	$9.2	$9.4	$8.4	$7.5
Replace Meters	$13.3	$11.8	$15.2	$14.9	$16.4
Support Facilities	$1.5	$5.0	$7.7	$5.5	$14.8
Base Total $	**$181.1**	**$164.6**	**$188.8**	**$226.1**	**$357.5**
Average (2012-2017)	**$223.6**				

Schedule 4 shows the breakdown of the electric capital spending categories as defined by the Company. Overall, the Company's total distribution base capital spending has generally increased since 2013. The Company's five-year (2013-2017) annual total distribution capital spending average is $223.6 million.

Q. Does the Company provide a projected electric baseline spending amount in its Petition for the period 2019-2022?

A. Yes, the Company provided projected electric baseline capital expenses for the period 2019-2022 in response to RCR-ENG-E-0001. The proposed electric baseline spending is presented in the schedule below.

Schedule 5 PSE&G's Projected Electric Distribution Spending Categories ($ millions)[41]

	2019	2020	2021	2022	2023
Replace Facilities	$121.2	$117.4	$132.8	$124.6	$124.6
System Reinforcement	$84.8	$90.9	$64.2	$68.5	$68.5
Environmental Regulatory	$5.2	$4.9	$6.1	$11.6	$11.6
Replace Meters	$18.2	$18.2	$18.2	$18.2	$18.2
Support Facilities	$2.5	$2.1	$11.8	$9.6	$9.6
Base Total $	**$231.8**	**$233.5**	**$233.1**	**$232.4**	**$232.4**

[40] RCR-ENG-E-0001
[41] RCR-ENG-E-0001

On a five-year average basis, the Company is proposing future electric baseline spending of $233 million.[42] However, the Company notes that the $233 million also includes Energy Strong II-like spending as shown below.

Schedule 6 PSE&G's Projected Electric Distribution Spending and Energy Strong II-like Work ($ millions)[43]

Capital Category ($M)	**2019**	**2020**	**2021**	**2022**	**2023**
Base (Energy Strong II-Like Work)	$51	$40	$20	$19	$20
Base (All Other)	$182	$193	$213	$214	$213
Total Base	$233	$233	$233	$233	$233
Percent Energy Strong II-like Work	22%	17%	9%	8%	9%

When we exclude the Energy Strong II like work from the projected baseline spending, it reduces the projected annual electric capital spending to $203 million. This amount is lower than the five-year historical electric capital base spending average of $223.6 million.

Q. Does the Company's Petition include an overall electric distribution capital budget projection including both PSE&G's IIP costs and baseline spending?

A. No. The Company only provides an overall projected electric base distribution spending summary for 2019-2023.[44] We have provided a summary of the Company's projected budget in the following schedule that includes <u>both</u> baseline and IIP spending. We present the 2019-2023 projected total electric IIP costs and baseline spending based on the Company's categorizations in the following schedule:

[42] Attachment 2 Schedule EFG-ESII-2B
[43] RCR-ENG-E-0001
[44] RCR-ENG-E-0001.

Schedule 7 Summary of PSE&G Baseline and Proposed Energy Strong II Electric Spending[45]

Spending (in millions)	2019	2020	2021	2022	2023
Proposed Baseline Spending	$233	$233	$233	$233	$233
Proposed Energy Strong II Spending	$42	$346	$557	$348	$204
Total Spending	$275	$579	$790	$581	$437

The above schedule shows the total electric distribution spending split among these components of the Company's proposed total distribution spending and the Company's proposed Energy Strong II spending. The schedule shows that PSE&G's proposed Energy Strong II program would range from 18 to 239 percent of the Company's projected annual baseline electric distribution capital spending of $233 million depending on the year. Over the entire 2019-2023 period, the Company's Energy Strong II program would represent 56 percent of the Company's total proposed electric distribution capital spending.

VIII. VEGETATION MANAGEMENT CONSIDERATIONS

Q. Please summarize your concerns regarding Vegetation Management and the Company's proposed enhanced Spacer and Increased Sectionalization subprograms.

A. We are concerned about the Company's proposed IIP treatment and scope of two subprograms (the Spacer Cable subprogram and Increased Sectionalization subprogram) in light of the fact that the Company has yet to complete a full

[45] RCR-ENG-E-0001

trimming cycle under the Board's 2016 Vegetation Management requirements.[46] In BPU Docket ER18010029 and GR18010030, we commented on the Company's vegetation management budgets and outages as part of the base rate case proceeding. Vegetation-related damages account for 80 percent of the outage durations for a 2010 Nor'easter event.[47]

We have two concerns. First, the Company's cost-benefit analysis for the Spacer Cable program and the Increased Sectionalization program are based on historical customer minutes of interruption ("CMI") between 2010 and 2016. The CMI do not include the impacts of the Board's 2016 Vegetation Management Regulations. The concern is that the benefits of the full trim cycle of the vegetation management program and these two subprograms may be double counted within the cost-benefit analysis thus overstating the benefits of the two subprograms. Second, because the Company has not yet completed a full cycle of tree-trimming under the 2016 Vegetation Management Regulations, we cannot fully assess the need for the two subprograms at this time. A full tree-trimming cycle should be completed, and the impact of the 2016 Vegetation Management Regulations should be assessed before approving the additional spending for these two subprograms.

Q. Please explain your concerns regarding the cost-benefit analysis.

A. To illustrate these concerns, the current spacer cable program cost-benefit ratio is based on a **[Begin PSE&G Confidential]** [redacted] **[End PSE&G Confidential]**

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[46] N.J.A.C 14:5-9.
[47] RCR-ENG-E-0133

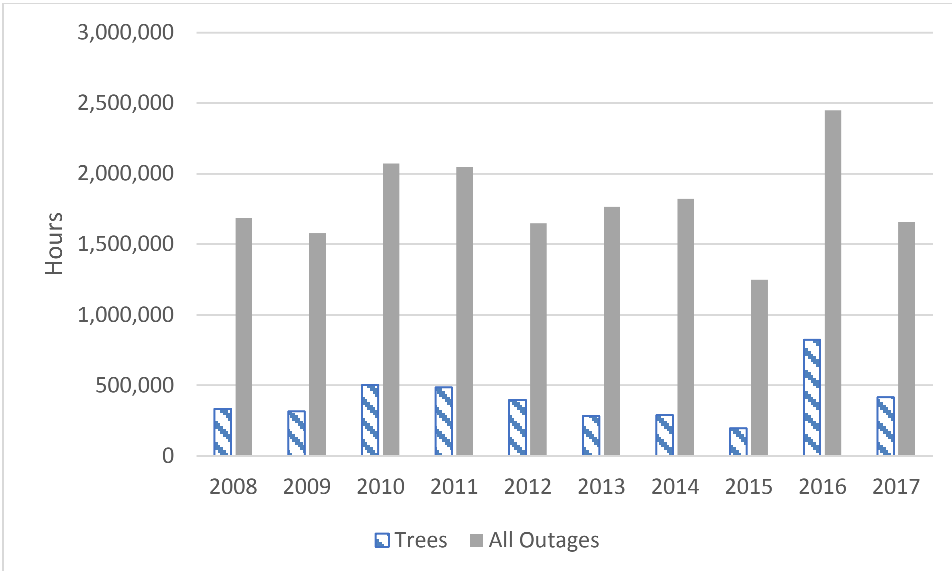
percent outage reduction factor (reportable and major events) in the Company's cost-benefit analysis. If, after completion of the vegetation management program, the reportable and major events outage reduction factor gets reduced below **[Begin PSE&G Confidential]** [redacted] **[End PSE&G Confidential]** percent, the subprogram is no longer cost-effective. Similarly, the cost-benefit ratio of the increased sectionalization program would also be reduced. Therefore, if there is a reduction in outage rates due to the vegetation management program, the cost effectiveness of both of these subprograms would be reduced considerably. We understand that Rate Counsel witness David Dismukes, PhD shares similar concerns about the assumptions used in the Company's cost-benefit analysis in his direct testimony.

Q. Are tree-related outages an issue for the Company?

A. We agree that the tree-related outages represent a major category of outage causes for the Company. Figure 1 shows historical (2008-2017) PSE&G Tree Related Outage durations (excluding major events) compared to all outages. Outage data provided by PSE&G show tree-related outages have historically represented 22 percent of all outage durations.[48] From 2015 through 2017 tree-related outages were 16 percent, 34 percent, and 25 percent of all outages respectively.[49] The proposed programs will help reduce tree-related outages, but the program will not eliminate all tree-related outages.

[48] RCR-ENG-E-0003
[49] Ibid.

Figure 1 PSE&G Historical Tree-Outage Duration (Excluding Major Events)[50]



The Company contends that one of the primary justifications for the two subprograms is to provide resiliency benefits in the event of major storms.[51] Specifically, the Company focused on the observation that 80 percent of the outage durations for a 2010 Nor'easter event were attributed to tree outages.[52]

Q. Has the Board undertaken steps to address tree-related outages across electric distribution companies throughout the state?

A. Yes. It is our understanding that the Company's current Vegetation Management program adheres to the revised regulations adopted by the Board in 2016. The Board's 2016 Vegetation Management Regulations include:[53]

- Four-year trim cycle;

[50] RCR-ENG-E-0003
[51] Direct Testimony of Edward Grey. June 8, 2018. Page 22, lines 17-20.
[52] RCR-ENG-E-0133
[53] N.J.A.C 14:5-9

- Hazard tree identification and management program;
- The removal of overhanging vegetation from the substation to the first protective device starting in January 2016; and
- Additional reporting requirements for vegetation management.

Q. Has the Company been able to determine the impacts of the Board's 2016 Vegetation Management Regulations across the entirety of its service territory?

A. No, simply because the Company has yet to complete an entire four-year trim cycle under the Board's 2016 regulations. We anticipate that the Company's vegetation management expenses have only recently begun to show accelerated spending. In BPU Docket ER18010029 and GR18010030, we commented on the trend in the Company's vegetation management budgets in response to the Board's 2016 Vegetation Management regulations. At this time, we recommend that the Board wait to assess the impacts of the Company's vegetation management program in order to determine whether or not the spacer cable subprogram is needed.

IX. COST-BENEFIT ANALYSIS CONCERNS

Q. Please summarize your concerns regarding the Company's cost-benefit analysis.

A. Our concern regarding the Company's cost-benefit analysis are summarized below:

- The Company's own cost-benefit analysis found its $906 million Substation Flood Mitigation and Substation upgrade programs are not cost-effective on either a net present value basis or a nominal basis.

We understand that Rate Counsel witness David Dismukes, PhD shares similar concerns about the Company's cost benefit analysis in his testimony.

Additionally, we believe that a cost-benefit analysis should be developed for each project within a program where specific costs and benefits can be derived for the individual project within a program. For example, each substation should, as contemplated by the regulations, include a cost-benefit analysis individually. Similarly, each circuit proposed to be reconductored with tree-wire should have a cost-benefit analysis conducted individually to be included in the program. Understandably, programs such as the ADMS program can only be evaluated on a program basis as its impacts will be seen across the entirety of the Company's service territory. The Company, in its filing, has only provided high level cost effectiveness information on a sub-program basis and has not offered cost-benefit information on an individual project basis.

Q. Please summarize the Company's cost-benefit analysis.

A. N.J.A.C. 14:3-2A.5(b)(3) requires the Company to provide an "applicable" cost-benefit analysis for each project as part of its IIP petition. The Company's cost-benefit results for the proposed electric program are summarized below on both a simple and net present value ("NPV") basis.[54]

Schedule 8 PSE&G's Energy Strong II Electric Cost-benefit Analysis on a Nominal Basis[55]

	Nominal ($ millions)		
Program	**Benefits**	**Costs**	**Benefit/Cost Ratio**
Substation	$662	$906	0.7
Outside Plant, Higher Design and Construction Standards	$961	$345	2.8
Contingency Reconfiguration Strategies	$1,882	$145	13.0
Grid Modernization	$611	$107	4.6
Total Energy Strong II	**$4,118**	**$1,503**	**2.7**

[54] The present value presents the Company's IIP program using discounted cash flows to account for the time value of money. The Company's nominal analysis does not make the time value of money adjustment. For purposes of evaluating the Company's IIP program, we use the discounted values.
[55] Attachment 5 Schedule-BV-ESII-Elec-4 Page 8.

[Begin PSE&G Confidential]

[redacted]

	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[End PSE&G Confidential]

The Company's analysis indicates that its proposed Energy Strong II program is marginally cost-effective with a cost-benefit ratio of 2.7 on a nominal basis and 1.4 on an NPV basis that discounts the costs and benefits using the Company's weighted average cost of capital ("WACC").[57, 58]

Q. Is there significance to the IIP Regulations' requirement that an applicant provide "any applicable cost-benefit analysis for each project"?

A. Yes. It is our interpretation that the Board requires each project to demonstrate its cost effectiveness. As a result, a company cannot simply design an IIP program that has one sub-program that is very cost-effective to mask other sub-programs

[56] RCR-ENG-E-0097 Confidential
[57] We do not opine the appropriateness of the Company's WACC.
[58] Attachment 5 Schedule-BV-ESII-ELEC-4 (Page 40 of 119)

that are not cost-effective. We believe that each sub-program needs to demonstrate that it is cost-effective to be included in an approved IIP program.

Q. Is there a program that does not meet the cost effectiveness threshold?

A. The Company's Substation program (Station Flood and Storm Surge Mitigation and Substation Upgrades (26/4 kV subprograms)) fails to meet a cost-effective threshold of 1.0 in the Company's own analysis. The two subprograms have a combined cost-benefit ratio of 0.7 on a nominal basis and **[Begin PSE&G Confidential]** [redacted] **[End PSE&G Confidential]** on a present value basis.[59]

Q. Does including the effects of Superstorm Sandy impact the Company's cost-benefit analysis?

A. As part of its Energy Strong II filing, the Company conducted a sensitivity analysis to include the impacts of a Superstorm Sandy-like event. Not surprisingly, the benefits attributed to avoiding Superstorm Sandy-like outages improve the overall cost-benefit ratio for the proposed Energy Strong II program. The Superstorm Sandy sensitivity analysis increases the nominal cost-benefit ratio to 3.6 and the present value ratio to 1.9.[60] The cost-benefit ratio for the substation program under the Superstorm Sandy sensitivity is **[Begin PSE&G Confidential]** [redacted] **[End PSE&G Confidential]** on a present value basis.

[59] Attachment 5, page 7.
[60] Attachment 5 Schedule-BV-ESII-ELEC-4 (Page 45 of 119)

Q. Is the observation that the Company's overall Energy Strong II program is shown to be cost-effective, justification for approving the entire program?

A. No. Each program and subprogram should be cost-effective. While the Company's inputs suggest that the overall IIP program is cost-effective as we have stated earlier, the Company's own analysis shows that the Substation Flood Mitigation and Substation Upgrades subprograms are not cost-effective and, therefore, should be excluded.

X. RATE COUNSEL ADJUSTMENTS TO ENERGY STRONG II ELECTRIC PROGRAMS

Q. What are your recommended adjustments to the PSE&G Energy Strong II electric programs?

A. As detailed below, we recommend that the Board approve a five-year $107 million IIP for the Company. Our adjustments to the Company's proposed $1,503 million program exclude many projects that should be considered regular and routine distribution spending of the sort historically and typically recovered through base rates and are not cost-effective.

Q. Please describe the process you followed to determine what projects should be excluded in the PSE&G Energy Strong II proposal.

A. Our process for determining qualifying projects is detailed below. First, qualifying projects must be incremental to baseline spending amounts. We recommend that approved programs be incremental to the calculated historical capital budget spending before being included in the program. As noted, based on historical capital spending for the past five years, the baseline spending of $223.6 million per year is reasonable. Second, we would consider the replacement of facilities or retirement of facilities that have reached their end-of-life to be normal reliability spending that should be done as part of baseline spending, not IIP spending through a clause. This would also include routine reliability spending since the Company is obligated to provide safe and reliable service as part of normal operations. As we have noted earlier, this should be limited to projects that would not have occurred without some acceleration, not programs currently in place as part of routine operations. Third, there must be an engineering report for each proposed project. The engineering report must identify specific benefits and an applicable cost-benefit analysis. Additionally, the engineering report should include project objectives, specific expected resiliency benefits, detailed cost estimates, cost-benefit analysis, and in-service dates. Fourth, the approved projects should include a level of risk and contingency that is more precise than office level estimates. The Company's broad simple project summaries do not meet the engineering report requirement required by the IIP Regulations.[61]

Q. Based on these recommendations, did you prepare an adjusted budget for the Energy Strong II electric program?

A. Yes, we recommend a number of adjustments to the Company's proposed Energy Strong II electric program that are summarized below in tabular form and discussed in more detail in this section.

[61] N.J.A.C. 14:3-2A.5(b)(3).

Schedule 9 Summary of Rate Counsel's Energy Strong II Electric Recommendations

Subprogram	Filed (000's)	Rate Counsel Recommendation(000's)
Substation Flood and Storm Surge Mitigation	$428,000	$0
Substation Upgrades 26/4 kV	$478,000	$0
Spacer Cable	$345,000	$0
Increased Sectionalization	$100,000	$0
Reclosing Devices	$45,000	$0
ADMS	$35,000	$35,000
Communications Network	$72,000	$72,000
Total	**$1,503,000**	**$107,000**

Q. What are your recommended adjustments to the PSE&G's Energy Strong II proposal?

A. As detailed below, we recommend that the Board approve a five-year $107 million Energy Strong II electric program for the Company. Our adjustments to the Company's proposed $1.503 billion program exclude many projects that we consider regular and routine distribution spending of the sort historically and typically recovered through base rates. In addition, approximately 60 percent of the projected cost of the Energy Strong II program is comprised of two subprograms that the Company's own analysis found to be **not** cost-effective.

Q. Do you find the proposed Energy Strong II electric projects to be imprudent?

A. The determination whether any of our excluded projects are prudent should be addressed in the Company's next base rate case proceeding, should the Company include them in a future proceeding. In this proceeding, we do not assess the reasonableness or prudency of these projects. We are strictly evaluating whether these electric projects should be included in the PSE&G's IIP, and therefore subject to the special cost recovery provisions allowed under the Board's IIP Regulations.

Q. Please describe your rationale for the adjustments for the Substation Flood and Storm Surge Mitigation subprogram.

A. Overall, we do not recommend including any of Substation Flood and Storm Surge Mitigation subprogram in our adjusted total for the Company's proposed Energy Strong II. As we have noted, the Company's own cost-benefit analysis found this program to not be cost-effective. Both substation subprograms are part of the Company's routine distribution spending to maintain reliability. We believe that the Company should undertake any substation reliability work that is prudent through its base rate mechanism.

The PSE&G Energy Strong II proposed electric substation sub-program follows the mitigation of the 27 substations damaged by Hurricane Irene and/or Superstorm Sandy under Energy Strong I. The Energy Strong I program addressed substations that were flooded either during Superstorm Sandy and/or Hurricane Irene. While portions of the 16 substations selected by PSE&G in

Energy Strong II are currently below the Company's FEMA plus one-foot standard, none of the substations have experienced outages related to flooding. The Clay Street and Constable Hook substations experienced some flooding during Superstorm Sandy.[62] None of the other substations have documented flooding. It appears that the Company included the substations because some part of the substation is below new flood level guidelines. We note that the average age of the 16 substations is 65 years.[63] The oldest is the Market street substation at 107 years and the youngest is the Kingsland substation at 34 years. The Company provided engineering reports conducted by independent engineering firms as part of Schedule-EFG-ESII-4 (confidential). **[Begin PSE&G Confidential]** [redacted][64] **[End PSE&G Confidential]**

PSE&G also describes what flood mitigation measures have been undertaken by the Company already. The Company has included flood mitigation work for five

[62] RCR-ENG-E-0011
[63] Ibid.
[64] Schedule EFG-ESII-4 Confidential

substations within its base capital plan.[65] Between 2015 and 2017, the Company has spent approximately $35 million on flood mitigation measures.[66]

Q. Please explain your rationale for excluding the Substation 26/4 kV Upgrade subprogram.

A. The average age of the 15 substations in the $478 million upgrade subprogram is 60 years (RCR-ENG-E-0009). Historical (2012-2017) base spending on substation elimination and life extensions has been $35.6 million under normal reliability work.[67] Until the filing of the Energy Strong II petition, the Company has not indicated that it was necessary to undertake a lifecycle replacement program to replace old operational substations.

The Company's asset management program is based on the probability of failure. The reality is more nuanced. The Company acknowledges that it has a maintenance program, and the outage evidence indicates that the Company has been successful at maintaining reliability with its current assets and that maintenance program. Overall, outages related to supply and station equipment failures comprise, on average, 11 percent of outage durations experienced by the Company (2008-2017).[68]

It is our understanding that the Company follows an annual portfolio optimization process as part of its analysis to develop an optimal spending portfolio that fits a given budget constraint, and produces the highest cumulative weighted benefit

[65] Direct Testimony of Edward Gray, Attachment 2, Page 16 lines 6-7
[66] RCR-ENG-E-0006
[67] RCR-ENG-E-0010
[68] RCR-ENG-E-0003

consistent with the Company's strategic objectives.[69] We note that the Company submitted these projects individually as mandatory projects.[70] However, the Company did not compare the results of its portfolio optimization process with the Black and Veatch risk model.[71] PSE&G did not provide information to indicate whether these projects would be selected or even proposed without the Energy Strong II petition.

Since the Company has not conducted engineering studies for the 15 substations, it is not known if the replacement of old equipment with new equipment will improve reliability or whether the new equipment merely reduces the probability of failure of the current equipment in place.[72]

Q. Please explain your rationale for excluding the Spacer Cable installation subprogram.

A. Overall, we do not recommend including the Spacer Cable Subprogram in our adjustment to the Company's proposed Energy Strong II electric program since the sub-program is a blanket program. Historically, the Company has included spacer cable replacement within the base capital plan.[73] Cumulative base substation spending has been $1.1 million between 2012 and 2017.[74] This amount of spending suggests that spacer cable and pole guying has not been a priority of the Company's electric distribution spending. Spacer cables help to improve

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[69] RCR-ENG-E-0047
[70] RCR-ENG-E-0048
[71] RCR-ENG-E-0047
[72] RCR-ENG-E-0012
[73] Direct Testimony of Edward Gray, Attachment 2, Page 25 lines 1-5
[74] RCR-ENG-E-0018

reliability by improving resistance from tree/limb contact. RCR-ENG-E-0013 shows the analysis conducted by the Company for tree-related outages between spacer and open wire. The Board's 2016 Vegetation Management Regulations increase trimming, which accomplishes the same goal as the spacer cable program. We recommend that the Spacer cable program be delayed or modified contingent on the completion of the first trimming cycle under the Board's 2016 Vegetation Management Regulations. The spacer program also includes some pole replacement costs. We view the pole replacement portion as base spending to maintain reliability.

Q. Please explain your rationale for excluding the Increased Sectionalization subprogram.

A. Unlike the Contingency Reconfiguration program implemented in Energy Strong I, this program does not target critical facilities. Further the Company has not provided a prioritization process to determine eligible circuits. We do not recommend the inclusion of the $100 million Increased Sectionalization subprogram because the Company has already undertaken contingency reconfiguration as part of its routine operations, although it does not specifically allocate any budget to this activity.[75] In the last five years, the Company has spent approximately $3.3 million on installation of reclosing devices and increased

[75] RCR-ENG-E-0027

sectionalization.[76] It is not clear to us why the Company should receive accelerated recovery for an activity that should be part of routine maintenance.

The Board's increased trimming requirements may obviate or reduce some of the need to increase sectionalization. Like the Spacer cable program, the increased sectionalization helps to improve reliability by providing multiple paths for circuits. The Board's 2016 Vegetation Management Regulations increase trimming requirements, thereby reducing tree-related outages. Eliminating tree-related outages reduces the need to provide sectionalization schemes that respond to outages. If the Board considers including the Increased Sectionalization subprogram, we recommend that the Increased Sectionalization subprogram under the Contingency Reconfiguration program be delayed or modified contingent on the completion of the first trimming cycle under the Board's 2016 Vegetation Management Regulations

Q. Did you make an adjustment for the Company's Reclosing Device subprogram?

A. Yes, we recommend eliminating the $45 million Recloser subprogram because the Company has already undertaken recloser installations as part of its routine operations. The total amount spent has been $3.3 million between 2012-2017

[76] RCR-ENG-E-0027

based on unit spending of $50,000 per recloser.[77] The data also indicates that the program is a blanket program that should not be included under an IIP.

Q. Are there possible IIP projects that you would recommend the Board to approve?

A. Yes, we have identified $107 million of proposed projects over the five-year period that may meet our criteria for the Board's IIP program, if supported by documentation such as detailed engineering reports, as discussed above and required by the IIP Regulations. The recommended projects are all Grid Modernization and Advanced Distribution Management projects that incorporate elements of advanced communications to enable remote control and operation. In the last five years, the Company has spent over $4.8 million total on grid modernization projects.[78]

The Company will also need to demonstrate the cost effectiveness, reasonableness and prudency of these selected projects in a future base rate case. Overall, subject to receiving detailed engineering reports, we recommend including the Company's proposed Grid Modernization subprogram which includes the Advanced Distribution Management System and Communication Network projects that are incremental to baseline spending since the distribution management system integration projects are specifically referenced in the IIP Regulations.[79] However, distribution automation projects must also be integral to

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[77] RCR-ENG-E-0027
[78] RCR-ENG-E-0031
[79] N.J.A.C 14:3-2A.2(a).

the distribution automation system itself and not a normal protection system or routine customer reliability expenditure. For example, a project to install an intelligent recloser that can operate in coordination with other distribution automation equipment and under the control of a distribution automation system would be included and may be appropriate as incremental Grid Modernization and Advanced Distribution Management System spending.

Schedule 10 Rate Counsel's Adjustments to Energy Strong II Electric Programs.

Subprogram	Filed (000's)	Rate Counsel Recommendation (000's)
Substation Flood and Storm Surge Mitigation	$428,000	$0
Substation Upgrades 26/4 kV	$478,000	$0
Spacer Cable	$345,000	$0
Increased Sectionalization	$100,000	$0
Reclosing Devices	$45,000	$0
ADMS	$35,000	$35,000
Communications Network	$72,000	$72,000
Total	**$1,503,000**	**$107,000**

Q. How do your adjustments compare with the Company's overall historical distribution budgets.

A. Our adjustments to the PSE&G IIP results in a total $107 million program, or about $21.4 million per year over the 2019-2023 period. Together with the five-year historical average baseline spending of $223.6 million over the 2019 – 2022 period, our recommended $21.4 million per year for Energy Strong II would result in an overall electric capital budget of $245 million per year for the 2019 - 2023 period. Moreover, these Energy Strong II capital projects require the Company to invest a baseline spending amount of $223.6 million per year <u>before</u> recovering the incremental $21.4 million per year under the IIP cost recovery mechanism.

XI. CONCLUSIONS AND RECOMMENDATIONS

Q. What are your recommendations?

A. Our findings and recommendations are summarized as follows:

- We find that the majority of the proposed programs are continuation of programs already undertaken by the Company as routine maintenance to maintain safe and reliable service and therefore should not receive accelerated recovery.
- We recommend that the Board require that the Company use its five-year historical average of $223.6 million for annual baseline electric capital spending.
- The Company's own cost-benefit analysis shows that the Substation program is not cost-effective under the Company's base case and Hurricane Sandy sensitivity case.
- The $478 million Substation Upgrade 26/4 kV subprogram is not supported by detailed engineering reports for each of the projects as

required under N.J.A.C 14:3-2A.5(b)(3). The Company only provided broad outlines of programs and does not provide individual project completion dates.

- The Company purports that its $345 million Spacer Cable subprogram and $145 million Increased Sectionalization subprogram have historically been part of base distribution spending. These programs are blanket programs that are a part of routine maintenance and should not be eligible for accelerated cost recovery. In addition, the Company has yet to complete a trimming cycle under the Board's 2016 Vegetation Management Regulations. These programs, if considered at all under the IIP Regulations, should be delayed or modified contingent on the completion of the first trimming cycle under the Board's new vegetation management program.
- If the Board were to proceed with approval of PSE&G's IIP, notwithstanding the identified deficiencies, we recommend that the Company approve of a five-year program of $107 million subject to the submittal of detailed engineering reports for the program. The $107 million budget reflects our adjustments to the Company's proposal removing all of the Company's proposed subprograms with the exception of the Communications Network and Advanced Distribution Management System subprograms.

Q. Does this conclude your testimony?

A. Yes. However, we reserve our right to modify our testimony based on additional information provided by the Company.

ATTACHMENTS

Charles P. Salamone P.E.

Profession: Power systems analysis and assessment, with a special emphasis on transmission planning, performance and design

Nationality: U.S. Citizen

Years of Experience: 40 years

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Summary: Mr. Salamone provides professional services based on 40 years of electric utility industry experience in the areas of Transmission Planning, Substation Planning, Distribution Planning, ISO-New England Planning Procedures, New England Power Pool Procedures, Congestion Management, Generator Interconnections, Planning/Capital Budget Management, Meter Engineering, and State (Mass DPU and New Jersey Rate Council) and Federal (FERC) Regulatory Agency Filing Development and Expert Witness Testimony

Experience:

2005- Pres. **Cape Power Systems Consulting**

Established a power system design, analysis, planning and assessment consulting company to work directly with diverse power system stakeholders.

- Worked with a number of clients for the development of analysis, reports and presentations in support of regulatory and technical review/approval process for transmission and distribution projects
- Provided technical assistance for transmission planning activities for an Independent System Operator including support for major transmission system expansion programs and development of a 10 year transmission plan
- Worked with a large Massachusetts Utility as an expert witness in support of State regulatory reviews for the siting of a major transmission system upgrade plan

- Worked with state regulatory agencies in support of electric utility rate case proceedings including expert witness testimony and assessment of electric utility performance
- Worked with multiple state regulatory agencies in support of review of electric utility smart grid initiatives including review of the technical performance, system benefits and viability of proposed electric utility programs
- Developed and conducted a comprehensive training program for implementation of an Energy Management System (EMS) based transmission system security assessment application for a large Massachusetts utility
- Worked with clients to conduct load flow assessment of transmission system performance for feasibility and reliability performance studies across New England and New York

1979-2005 **NSTAR (Previously Boston Edison and Commonwealth Electric)**

2000-2005 ***Director System Planning***

NSTAR (Previously Boston Edison and Commonwealth Electric) Boston, MA

- Responsible for long term planning of Company transmission, substation and distribution systems
- Successfully managed the studies, design, internal and external review and regulatory approval for a $250M 345 kV underground transmission expansion project serving the greater Boston area
- Managed numerous generator interconnection studies, design and approvals
- Successfully managed studies, design and approval for congestion mitigation plans and expansion project
- Oversaw transmission and distribution planning efforts to establish a comprehensive 10 year $300 million system expansion plan
- Served as Company representative on NEPOOL Reliability Committee and the New England Transmission Expansion Advisory Committee
- Served as Company expert witness for system planning related regulatory proceedings at both the state and federal levels.
- Supervised a staff of 10 senior engineers

1989-1999 ***Manager, System Planning and Meter Services***

Commonwealth Electric Company, Wareham, MA

- Develop risk based prioritized $10 million construction budget procedures
- Supervise a staff of 6 professional engineers and 4 analysts
- Served as chair of the NEPOOL Regional Transmission Planning Committee (currently the NEPOOL Reliability Committee)
- Process billing determinant and interval data for all major system customers
- Lead implementation of first MV90 meter data processing system
- Develop annual performance analysis reports for all transmission and major distribution systems

- Manage multiple FERC tariff based transmission customer and generation developer system impact studies
- Served as expert Company witness in State and FERC regulatory proceedings
- Implemented a risk index for prioritization of all transmission and major distribution construction projects
- Implemented automated electronic processing of major customer billing data, which significantly reduced time needed to generate bills
- Served as lead member on information technology company merger team
- Implemented process and equipment to perform all tie line, generator and wholesale customer meter testing
- Served as chair of the NEPOOL Planning Process Subcommittee, which established numerous NEPOOL policies for transmission/generator owners
- Served as Vice-Chair of the NEPOOL Reliability Committee

1984-1989 ***Meter Engineer***
Commonwealth Electric Company, Plymouth, MA

- Designed and supervised installation of 15 generator meter data recorders
- Developed customer load plotting and analysis software
- Developed meter equipment order data processing system for four remote offices
- Implemented PC control of meter test boards, which significantly reduced processing and record keeping time
- Managed programming of all electronic meter registers to insure accurate data registration

1979-1984 ***Computer Application Engineer***
Commonwealth Electric Company, Wareham, MA

- Implemented numerous technical and analytical software applications for engineering analysis
- Served as member of decision team for implementation of a new SCADA system

1978-1979 **San Diego Gas & Electric, *Planning Engineer***
San Diego Gas & Electric Company, San Diego, CA

- Performed extensive stability analysis for a new 230 kV transmission interconnection with Mexico
- Performed transmission design and performance analysis for a new 250 mile 500 kV line from San Diego to Arizona

1973-1978 **New England Gas & Electric Association, *Planning Engineer***
New England Gas & Electric Association, Cambridge, MA

- Performed extensive stability analysis for a new 560 MW generating plant on Cape Cod
- Developed transmission plan for a new 345 kV transmission line on Cape Cod
- Developed plans for design and sighting of new 115 / 23 kV substations on Cape Cod

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, 2013 – present, *Associate*, 2008 – 2013.

Consults and provides analysis of technologies and policies, electric policy modeling, evaluation of air emissions of electricity generation, and other topics including energy efficiency, consumer advocacy, environmental compliance, and technology strategy within the energy industry. Conducts analysis in utility rate-cases focusing on reliability metrics and infrastructure issues and analyzes the benefits and costs of electric and natural gas energy efficiency measures and programs.

Environmental Health and Engineering, Newton, MA. *Senior Scientist*, 2001 – 2008.

Managed complex EPA-mandated abatement projects involving polychlorinated biphenyls (PCBs) in building-related materials. Provided green building assessment services for new and existing construction projects. Communicated and interpreted environmental data for clients and building occupants. Initiated and implemented web-based health and safety awareness training system used by laboratories and property management companies.

The Penobscot Group, Inc., Boston, MA. *Analyst*, 1994 – 2000.

Authored investment reports on Real Estate Investment Trusts (REITs) for buy-side research boutique. Advised institutional clients on REIT investment strategies and real estate asset exchanges for public equity transactions. Wrote and edited monthly publications of statistical and graphical comparison of coverage universe.

Harvard University Extension School, Cambridge, MA. *Teaching Assistant*, 1995 – 2002.

Teaching Assistant for Environmental Management I and Ocean Environments.

Brigham and Women's Hospital, Boston, MA. *Cancer Laboratory Technician*, 1992 – 1994.

Studied the biological mechanism of tumor eradication in mouse and human models. Organized and performed immunotherapy experiments for experimental cancer therapy. Analyzed and authored results in peer-reviewed scientific journals.

EDUCATION

Harvard University, Cambridge, MA
Master of Science in Environmental Science and Engineering, 2000

Cornell University, Ithaca, NY
Bachelor of Arts in Biology and Classics, 1992

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Chang, M. 2014. *Making the Grid More Resilient within Reason: Case Study in Public Service Electric and Gas "Energy Strong" Petition.*

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Koplow, D., M. Chang. 2013. *Vogtle 3 and 4 Conditional Loan Guarantee: Review of Documents Pertaining to Department of Energy Conditional Loan Guarantees for Vogtle 3 & 4.* Synapse Energy Economics and Earth Track.

Chang, M., D. White, E. Hausman. 2012. *Risks to Ratepayers: An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation.* Synapse Energy Economics for Consumers Against Rate Hikes.

Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region.* Synapse Energy Economics for Energy Future Coalition.

Chang, M., D. White, P. Knight, B. Biewald. 2012. *Energy Benefits Resulting from the Investment of 2010 RGGI Auction Revenues in Energy Efficiency*. Synapse Energy Economics for Regulatory Assistance Project.

Chang, M., D. White, E. Hausman, N. Hughes, B. Biewald. 2011. *Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the US.* Synapse Energy Economics for Union of Concerned Scientists.

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New Jersey Board of Public Utilities (Docket No. ER18010029 and GR18010030): Direct testimony on Public Service Electric and Gas' petition for base rate adjustments. On behalf of the New Jersey Division of Rate Counsel. August 6, 2018.

Illinois Commerce Commission (Docket No. 18-0211): Direct Testimony regarding Ameren Illinois Company's voltage optimization plan and the importance of prioritizing low-income communities. On behalf of the People of the State of Illinois, represented by the Office of the Illinois Attorney General. March 7, 2018.

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New Jersey Board of Public Utilities (Docket No. ER14030250): Direct testimony on Rockland Electric Company's petition for investments in storm hardening measures. On behalf of the New Jersey Division of Rate Counsel. September 4, 2015.

Hawaii Public Utilities Commission (Docket No. 2015-0022): Direct testimony on reliability, clean energy, competition, and management and performance concerns related to the petition of NextEra Corporation and Hawaiian Electric Companies (HECO) for the acquisition of HECO by NextEra. On behalf of the Hawaii Division of Consumer Advocacy. August 10, 2015.

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State of New Jersey Board of Public Utilities (Docket No. EM14060581): Direct testimony on the reliability commitments filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities. On behalf of the New Jersey Division of Rate Counsel. November 14, 2014.

District of Columbia Public Service Commission (Formal Case No. 1119): Direct and answer testimony on the reliability, risk, and environmental impacts of the proposed Exelon-Pepco merger. On behalf of the District of Columbia Government. November 3, 2014 and March 20, 2015.

United States District Court District of Maine (C.A. No. 1:11-cv-00038-GZS): Declaration regarding the ability of the New England electric grid to absorb the impact of a spring seasonal turbine shutdown at four hydroelectric facilities. On behalf of Friends of Merrymeeting Bay and Environment Maine. March 4, 2013.

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New Jersey Board of Public Utilities (Docket No. GO12050363): Testimony regarding the petition of South Jersey Gas Company for approval of the extension of energy efficiency programs and the associated cost recovery mechanism pursuant to N.J.S.A 48:3-98:1. On behalf of the New Jersey Division of Rate Counsel. November 9, 2012.

Resume updated December 2018.