Utility 2.0 Long Range Plan & Energy Efficiency, Beneficial Electrification and Demand Response Plan

2022 Annual Update

Prepared for Long Island Power Authority

July 1, 2022

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Executive Summary

PSEG Long Island (the Utility) is submitting this ***Utility 2.0 Long Range Plan (Utility 2.0 Plan)*** for review by the Long Island Power Authority (LIPA) and the New York State Department of Public Service (DPS). This submittal is in accordance with Public Authorities Law Section 1020-f(ee) and the Amended and Restated Operations Services Agreement dated December 31, 2013, and updated March 30, 2022. This Utility 2.0 Plan Filing details 22 initiatives previously reviewed by DPS and approved in prior years by the LIPA Board of Trustees. PSEG Long Island seeks a positive recommendation on the Utility 2.0 Plan from DPS and incremental funding approval from LIPA for three proposed initiatives.

This Utility 2.0 Plan Filing also includes the 2023 update to PSEG Long Island's ***Energy Efficiency, Beneficial Electrification and Demand Response (EEBEDR) Plan*** (included as Appendix A). PSEG Long Island's energy efficiency (EE) programs make a wide selection of incentives, rebates, and programs available to residential and commercial customers on Long Island to assist them in reducing their energy usage, thereby lowering their energy bills.

PSEG Long Island is Evolving its Utility 2.0 Vision

As New York State evaluates the progress-to-date of the Climate Leadership and Community Protection Act (Climate Act) and plans for increasing targets over the next three decades, PSEG Long Island recognizes the need to maintain flexibility and adaptability in response to evolving priorities. In collaboration with DPS, LIPA, and New York State Energy Research and Development Authority (NYSERDA), PSEG Long Island evolved its Utility 2.0 vision and framework to align with the five strategic priority areas presented in Figure ES-1, as well as the goal of increased focus on disadvantaged communities.

Figure ES-1. New York State 2023 Strategic Priorities and PSEG Long Island's Utility 2.0

Where the Utility historically focused implementation on innovative technologies that are characteristic of the utility of the future, PSEG Long Island is now shifting its focus to decarbonization outcomes that are *enabled* by the utility of the future as presented in its new Utility 2.0 vision (Figure ES-2).

Figure ES-2. PSEG Long Island's Utility 2.0 Vision (2022 Update)

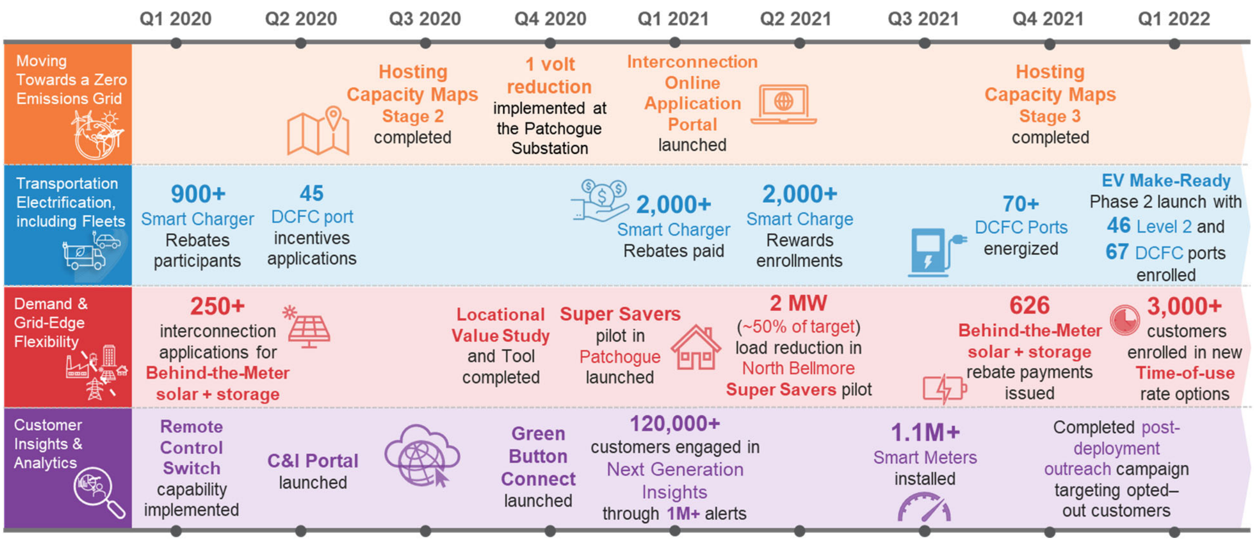
PSEG Long Island's Utility 2.0 vision is to be a customer-centric, innovative, and forward-looking utility that is dedicated to driving a decarbonized future. PSEG Long Island will achieve this vision by enabling building decarbonization solutions, moving towards a zero-emissions grid, enabling transportation electrification, delivering benefits to disadvantaged communities, implementing demand and grid-edge flexibility, and offering customer insights.

PSEG Long Island's 2022 Utility 2.0 Plan is representative of a one-year outlook. The Utility intends to leverage the outcomes of several clean energy studies and plans that are still under development across the state to best inform their long-range strategy. Outcomes of these outstanding initiatives (Section 1.5) will be vital to ensure PSEG Long Island's future Utility 2.0 and EEBEDR Plans are setup for success. PSEG Long Island aims to deliver a 5-year Utility 2.0 Plan in 2023.

Transitioning 2018 and 2019 Utility 2.0 Initiatives to the Next Stage

Since 2018, through the Utility 2.0 Program, PSEG Long Island has deployed more than 1 million smart meters across its service territory and delivered advanced metering benefits and operational savings to customers on Long Island. The Utility also advanced deployment of Distributed Energy Resources (DER) by providing resources for developers to interconnect and assess solutions to relieve grid constraints. Figure ES-3 presents these as well as other Utility 2.0 highlights from the past year.

Figure ES-3. Success of Utility 2.0 Initiatives as of Quarter 1 2022



PSEG Long Island, working with LIPA, continuously seeks ways to evolve its solutions and services to support its customers and their needs. As initiatives reach their last year of Utility 2.0 planned funding or original scope of work, PSEG Long Island considered the following four options:

1. **operationalize** any ongoing budget, maintenance, and management within core business operations,

2. **continue** operating through the Utility 2.0 program by proposing an expanded scope and requesting additional funding in the Utility 2.0 Plan,

3. **cancel** all efforts and spending to reevaluate and potentially repropose the initiative through a future Utility 2.0 Plan, or

4. confirm the scope is **complete** and no further spending is required.

In 2023, twelve of the projects and initiatives borne out of PSEG Long Island's Utility 2.0 program will transition into becoming part of the Utility's core operations to make way for the next evolution of Utility 2.0 (Table ES-1 plus the Program Management Office).

Table ES-1. Utility 2.0 Initiatives becoming Operationalized in 2023

Project Status	Moving Towards a Zero Emissions Grid	Demand & Grid-Edge Flexibility	Customer Insights & Analytics
OPERATIONALIZED IN 2023	1. Utility of the Future Team 2. Hosting Capacity Maps Stage 3	3. BTM Storage with Solar Program 4. Locational Value Study 5. Non-Wires Alternatives Planning Tool 6. NWA Process Development 7. Rate Modernization - TOU	8. AMI Technology and Systems 9. AMI Customer Engagement 10. AMI-Enabled Capabilities 11. Data Analytics 12. Next Generation Insights

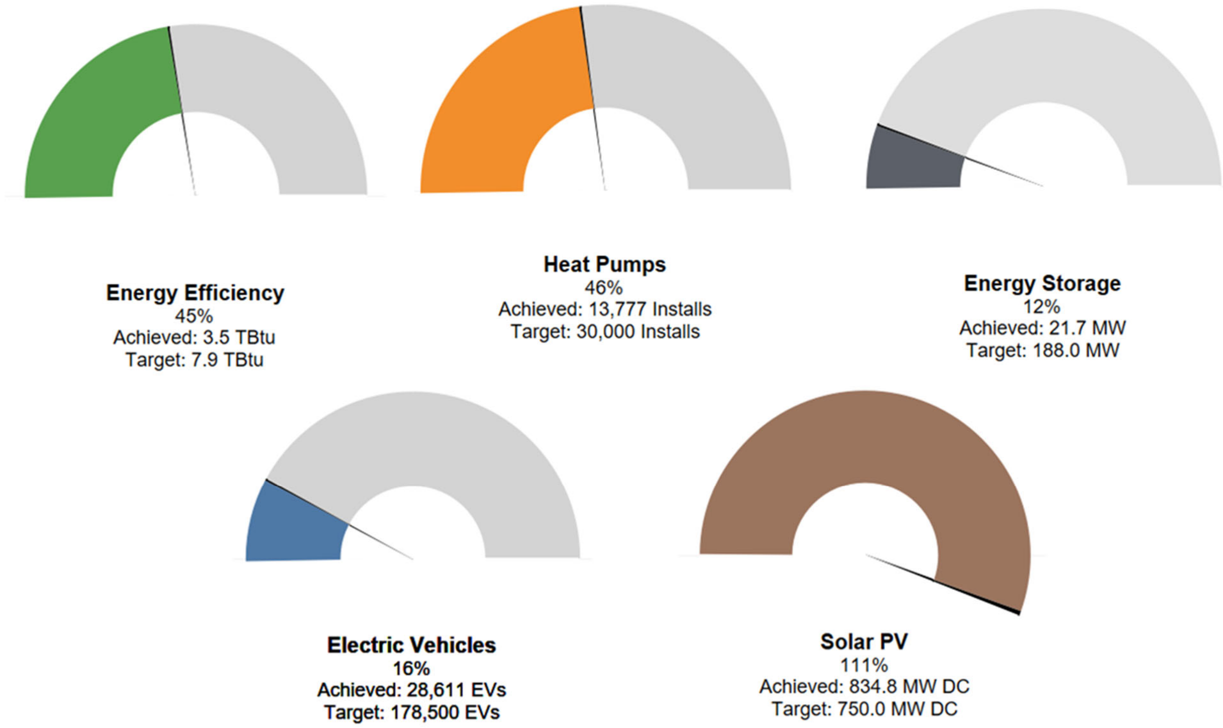
These initiatives will transition to PSEG Long Island's core operations and base budget. Due to the Utility and LIPA's internal financial processes, the effective date for initiatives to be deemed operationalized is January 1, 2023. Within this Utility 2.0 Plan these initiatives have been labeled with a 2023 status of "operational."

Long Island Supports the Achievement of Statewide Clean Energy Goals

Utility 2.0 initiatives that are underway are directly contributing to achieving goals in areas such as energy storage and electric vehicles. In addition, PSEG Long Island has several long running EE programs and customer offerings that contribute to EE and heat pump targets that are included in the EEBEDR Plan (Appendix A). LIPA and PSEG Long Island are also supporting state clean energy goals in several ways that go beyond the initiatives included in the Utility 2.0 and EEBEDR Plans including utility scale solar, wind, and battery storage (Section 3.6)

PSEG Long Island's progress towards Long Island's portion of the State's Clean Energy Goals as of Q1 2022 is presented in Figure ES-4.

Figure ES-4. Progress Toward Long Island's Portion of the State's 2025 Clean Energy Goals



Current as of: March 2022 (Solar PV, EE, Heat Pumps, and Electric Vehicles) and Feb 2022 (Energy Storage) based on data availability. EE savings reflects savings since 2019. Heat pump installations reflect installations since 2020.

PSEG Long Island uses a variety of qualitative criteria to determine which projects to fund through Utility 2.0 including but not limited to:

- **New York State priorities** as presented in the Climate Act and provided through additional guidance and feedback from the DPS via the Utility 2.0 Plan annual filing process,

- **LIPA priorities, commitments and metrics** as defined in the Operations Services Agreement (OSA) and provided through additional guidance from LIPA via the Utility 2.0 Plan annual filing process and,

- **Similar projects across the Joint Utilities** as identified through coordinated communication and planning.

PSEG Long Island requires a total of $24.9M for active initiatives in 2023. Full details on projects costs and variances by year can be found in Section 7.2 with project-specific details in the sections identified in the table below.

The three active initiatives with the largest variances are:

1. **Grid Storage (Miller Place):** In the time since the project was approved, battery costs have increased significantly. This led to the requirement for a new vendor quote to reflect battery procurement costs in 2022 and the increased capital costs shown below. The increase in battery cost is attributed to the material cost increase associated with the battery technology (e.g., cost of lithium). O&M costs remain largely as previously forecasted.

2. **EV Make-Ready Program:** Due to the shift in business model for small DCFC projects (i.e., rebate model) and reassessment of make-ready infrastructure costs (i.e., CS-MR comprising the bulk of total make-ready infrastructure costs), majority of the budget shifted from capital to O&M.
3. **DER Visibility Platform:** The DER Visibility project budget is reflective of the recommendation by the DPS to utilize the annual Utility 2.0 filing to request the associated capital funding to support the IT Labor, developer-required licenses, and other capital costs for the upcoming year. As such, 2023 capital costs were not included in the previously approved budget and now appear as a variance.

Table ES-2. 2023 Reconciled Funding for Active Initiatives

Initiative	Document Section	Capital 2023 ($M)	O&M 2023 ($M)
Grid Storage (Miller Place)	*3.3*	6.29	0.00
EV Make-Ready Program	*4.1*	2.56	7.41
Suffolk County Bus Make-Ready Pilot	*4.2*	0.00	0.04
EV Program	*4.3*	0.00	2.74
Connected Buildings Pilot	*5.3*	0.00	0.08
DER Visibility Platform	*5.4*	3.31	0.06
Super Savers (Patchogue)	*5.9*	0.00	0.79
C&I Demand Alert Pilot	*6.7*	1.52	0.10
		13.69	**11.22**

PSEG Long Island is requesting funding to implement three new initiatives starting in 2023. Consistent with the updated Utility 2.0 Vision, the proposed initiatives support one or more of the six strategic priority areas.

The three new initiatives seeking funding are:

1. **Storage and EV Hosting Capacity Maps:** Maps to help facilitate storage integration and electric vehicle (EV) charging equipment deployment throughout PSEG Long Island's service territory. The Utility plans to build the storage and EV maps such that developers and customers can log into a single platform to see all available hosting capacity maps.
2. **Residential Energy Storage System Incentive:** An incentive program to provide customers with upfront incentives for purchasing and installing energy storage systems (ESS). The upfront incentives will be available for PSEG Long Island residential customers, including low-to-moderate income (LMI), installing ESS paired with new or existing solar.
3. **Integrated Energy Data Resource (IEDR):** The Statewide IEDR Platform being developed by NYSERDA has the potential to improve or accelerate investment, operational, or regulatory decisions related to DER, EE, environmental justice, or electrification strategies for transportation and buildings, thereby facilitating faster fulfillment of Climate Act objectives.

Table ES-3 summarizes the funding request for these initiatives.

Table ES-3. 2023 Funding Request for New Initiatives

Initiative	Document Section	Capital 2023 ($M)	O&M 2023 ($M)
EV & Storage Hosting Capacity Maps	**3.1**	1.93	-
Residential Storage	**5.1**	-	1.20
IEDR Platform	**6.1**	4.60	0.10

	6.53	**1.30**

Combining the reconciled funding for active projects and the initial requested funding for new initiatives, the total Utility 2.0 funding request for 2023 is $34.43 million ($21.9M in capital and $12.53M in O&M).

Table ES-4. 2023 Total Funding Request (Active and New)

Initiative	Capital 2023 ($M)	O&M 2023 ($M)	Total 2023 ($M)
Storage + EV Hosting Capacity Maps	1.93	0.00	**1.93**
Utility-Scale Storage - Miller Place	6.29	0.00	**6.29**
EV Make-Ready Program	2.55	7.39	**9.95**
Suffolk County Bus Make-Ready Pilot	0.00	0.04	**0.04**
EV Program	0.00	2.73	**2.73**
Residential Energy Storage System Incentive	0.00	1.20	**1.20**
Connected Buildings Pilot	0.00	0.08	**0.08**
DER Visibility Platform	3.32	0.06	**3.38**
Super Savers (Patchogue)	0.00	0.79	**0.79**
IEDR Platform	4.60	0.10	**4.70**
C&I Demand Alert Pilot	1.52	0.09	**1.61**
Total	**20.22**	**12.48**	**32.69**

PSEG Long Island’s 2023 EEBEDR Plan

PSEG Long Island’s EE programs provide a wide array of incentives and rebates to residential, including LMI, and commercial customers to assist them in reducing their energy usage, thereby lowering their bills. The Utility’s proposed 2023 EEBEDR Plan (included as Appendix A of this document) consists of four programs for residential customers and a multifaceted program for commercial customers.

Table ES-5. Summary of Proposed Programs and Budgets in the 2023 EEBEDR Plan

Program	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Energy Efficient Products	339,857	103,400	16. 9
Home Comfort	110,518	2,340	14.1
REAP (Low-Income)	10,884	2,020	1.9
Home Performance	31,426	1,906	7.5
Multifamily	8,928	1,839	0.79
All Electric Homes	1,038	28	0.15
Commercial Efficiency	286,309	90,242	38.9
HEM (Behavioral)	111,770	32,758	2.00

Program	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Total, Budget Components with Programmatic Savings	**900,730**	**234,534**	**82.21**
DLM Program	N/A	N/A	1.53
Market Development Fund	N/A	N/A	0.40
Clean Green Schools	N/A	N/A	0.05
PSEG Long Island Labor	N/A	N/A	3.20
Outside Services	N/A	N/A	2.16
Advertising	N/A	N/A	2.30
G&A	N/A	N/A	0.90
Community Solar	N/A	N/A	0.40
Total, Budget Components Not Associated with Programmatic Savings	**-**	**-**	**10.94**
Total	**900,730**	**234,534**	**93.15**

Table ES-6. Income-Eligible Customer Goals in the EEBEDR Plan

Program	Savings (MMBtu)	Program Budget ($M)
Home Comfort – Whole House LMI	10,634	3.9
REAP	10,884	1.9
Home Performance - LMI	13,292	5.5
Marketing & Outreach	-	1.00
Total	**34,810**	**12.35**

Delivering Benefits to Disadvantaged Communities

The Climate Act commits to supporting an equitable and just clean energy transition in New York recognizing that climate change impacts can disproportionately burden traditionally underserved communities. To ensure that New York State's clean energy policies deliver equitable benefits, the Climate Justice Working Group (CJWG) was formed to develop criteria for identifying these disadvantaged communities (DACs). In March 2022, the CJWG released the draft criteria for public comment which are expected to be finalized later in 2022.

Delivering a target 35% of energy efficiency benefits to residential and business customers in disadvantaged communities is one of the six strategic priorities identified by the State for 2023. PSEG Long Island is committed to developing programs, services, and other offerings to support and include LMI and DAC customers and will continue to monitor Climate Act working groups. As the criteria is being finalized, PSEG Long Island has begun to identify existing and potential new EE, heat pump and electric vehicle incentives and programs that will target these customers and communities.

PSEG Long Island's 2023 EEBEDR Plan (Appendix A7.3Appendix A) identifies opportunities to advance energy affordability for LMI consumers such as through heat pump rebates and programmatic changes designed to enhance the Home Performance and Residential Energy Affordability Partnership (REAP) programs that will total about $11 million in spending in 2023, more than double the amount in 2022, which represents roughly one-quarter of the non-residential rebate, incentive, and implementation spending

PSEG Long Island is formulating a plan in consultation with its strategic marketing and advertising agency to support the Utility's goal of delivering at least 35% of energy efficiency benefits to residential and business customers in disadvantaged communities or in income-qualified households.

Structure of the Document

This annual update of the Utility 2.0 Plan includes reporting around the status, performance, and spend for previously approved initiatives. PSEG Long Island expects that performance and budget spend will fluctuate year-to-year throughout the duration of the various initiatives. Unless otherwise noted in this Plan, PSEG Long Island intends to deliver the scope of the approved initiatives within the overall approved funding and schedule.[1]

The reporting of updates to approved initiatives and the proposals for new initiatives are included in Chapters 3 through 6. Key figures, such as quantifiable benefits and spend, are summarized at the portfolio level in Chapter 7.

Overall, the 2022 Utility 2.0 Plan filing is organized in the following way:

- **Chapter 1** outlines how PSEG Long Island is evolving its Utility 2.0 vision and strategy around New York State's strategic priorities for 2023, how the Utility 2.0 program has grown and is being managed to drive outcomes, how initiatives in and outside of Utility 2.0 support the achievement of state goals and how the Utility will plan to deliver benefits to DACs.
- **Chapters 2 through 6** describe the following for five New York State 2023 priorities:
  - design, justification, and funding request for new initiatives that will start in 2023,
  - progress updates, performance reporting, and budget reconciliation for approved initiatives, and
  - short descriptions of initiatives outside of Utility 2.0 that are contributing to state climate goals.
- **Chapter 7** provides an overview of the overall Utility 2.0 portfolio benefits, spend, and budgets. This chapter also outlines the expected rate impacts from the overall portfolio based on the expected spend and benefits.
- **Appendix A** contains PSEG Long Island's 2023 EEBEDR Plan.
- **7.3Appendix B** contains PSEG Long Island's revised BCA Handbook.
- **7.3Appendix C** provides a summary of the way LIPA and PSEG Long Island are organized.
- **7.3Appendix D** includes a listing of acronyms and abbreviations used in this document.

[1] The duration of the approved funding for each initiative will vary depending on when they were originally filed and whether the schedule for the initiative has been subsequently updated to reflect a change in the end date. For clarity, the duration of each initiative has been noted separately and individually for each initiative in Chapters 3 through 6.

1. Introduction

PSEG Long Island (the Utility) is submitting this Utility 2.0 Long Range Plan (Utility 2.0 Plan) for review by the Long Island Power Authority (LIPA) and the New York State Department of Public Service (DPS). This submission is in accordance with Public Authorities Law Section 1020-f(ee) and the Amended and Restated Operations Services Agreement dated December 31, 2013, and updated March 30, 2022.

1.1 Evolving PSEG Long Island's Utility 2.0 Vision

The global energy industry is approaching a critical transition point. Alongside ongoing changes in customer preferences and rapidly improving technologies, July 2022 marks three years since New York State's Climate Leadership and Community Protection Act (Climate Act), one of the most ambitious climate laws in the world, was signed into law. Several of the Climate Act's original clean energy targets were set for 2025, making 2022 the halfway point from when the law was enacted.

As the State evaluates progress to date and plans for increasing targets over the next three decades, PSEG Long Island recognizes the need to maintain flexibility and adaptability in response to shifting priorities. In collaboration with DPS, LIPA, and NYSERDA, PSEG Long Island evolved its Utility 2.0 vision and framework to align with the following six strategic priority areas.

- Building Decarbonization and Envelope Improvements
- Moving Towards a Zero Emissions Grid
- Transportation Electrification
- Delivering Benefits to Disadvantaged Communities
- Demand and Grid Edge Flexibility
- Customer Insights and Analytics

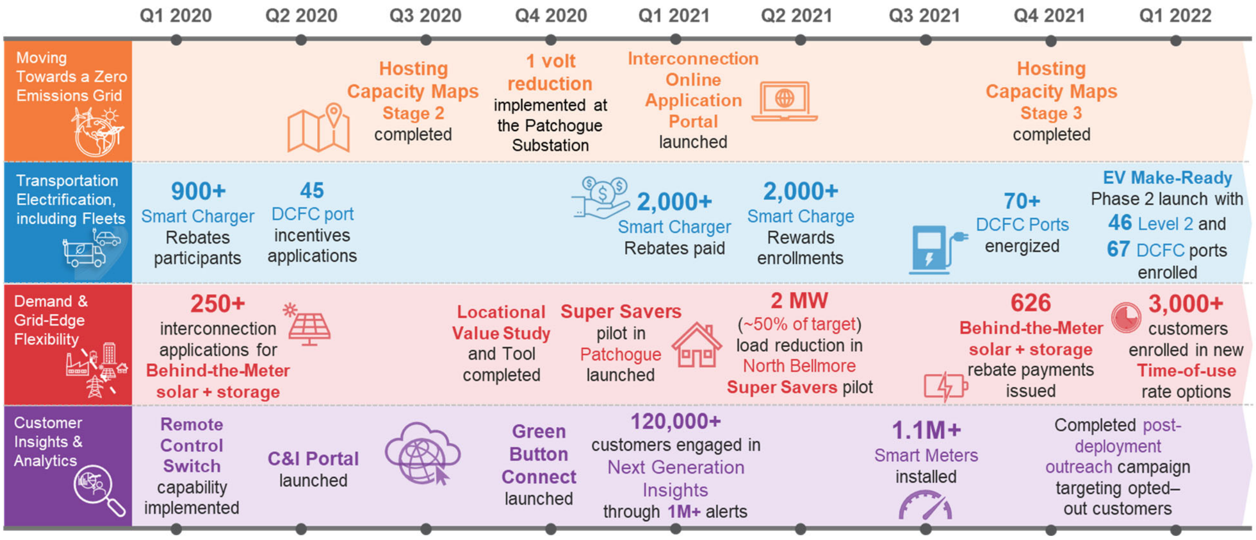
Where the Utility historically focused on implementation of innovative technologies that are characteristic of the utility of the future—including customer-sited energy efficiency (EE) and distributed energy resources (DER), data analytics solutions, advanced grid planning—PSEG Long Island is now shifting its focus to decarbonization outcomes that are *enabled* by the utility of the future. A new Utility 2.0 vision underpins PSEG Long Island's commitment to decarbonization (Figure 1-1).

Figure 1-1. PSEG Long Island's Utility 2.0 Vision (2022 Update)

PSEG Long Island's Utility 2.0 vision is to be a customer-centric, innovative, and forward-looking utility that is dedicated to driving a decarbonized future. PSEG Long Island will achieve this vision by enabling building decarbonization solutions, moving towards a zero-emissions grid, enabling transportation electrification, delivering benefits to disadvantaged communities, implementing demand and grid-edge flexibility, and offering customer insights.

PSEG Long Island previously executed its Utility 2.0 vision across three strategic pathways: Empowering Customers through AMI and Data Analytics, Exploring New Innovative Offerings, and Evolving into a Customer-Centric DSP. Guided by these pathways since 2018, PSEG Long Island deployed more than 1.1 million smart meters across its service territory and delivered advanced metering benefits and operational savings to customers along Long Island and the Rockaways. The Utility also advanced deployment of DER by providing resources for developers to interconnect and assess solutions to relieve grid constraints.

Figure 1-2. Success of Utility 2.0 Initiatives as of Quarter 1 2022



PSEG Long Island, working with the DPS and LIPA, continuously seeks ways to evolve its solutions and services to support its customers and their needs. In 2023, many of the projects and initiatives borne out of PSEG Long Island's Utility 2.0 program will transition into becoming part of the Utility's core operations. The successful integration of projects founded under the three strategic pathways into PSEG Long Island's operational activities makes way for the next evolution of Utility 2.0.

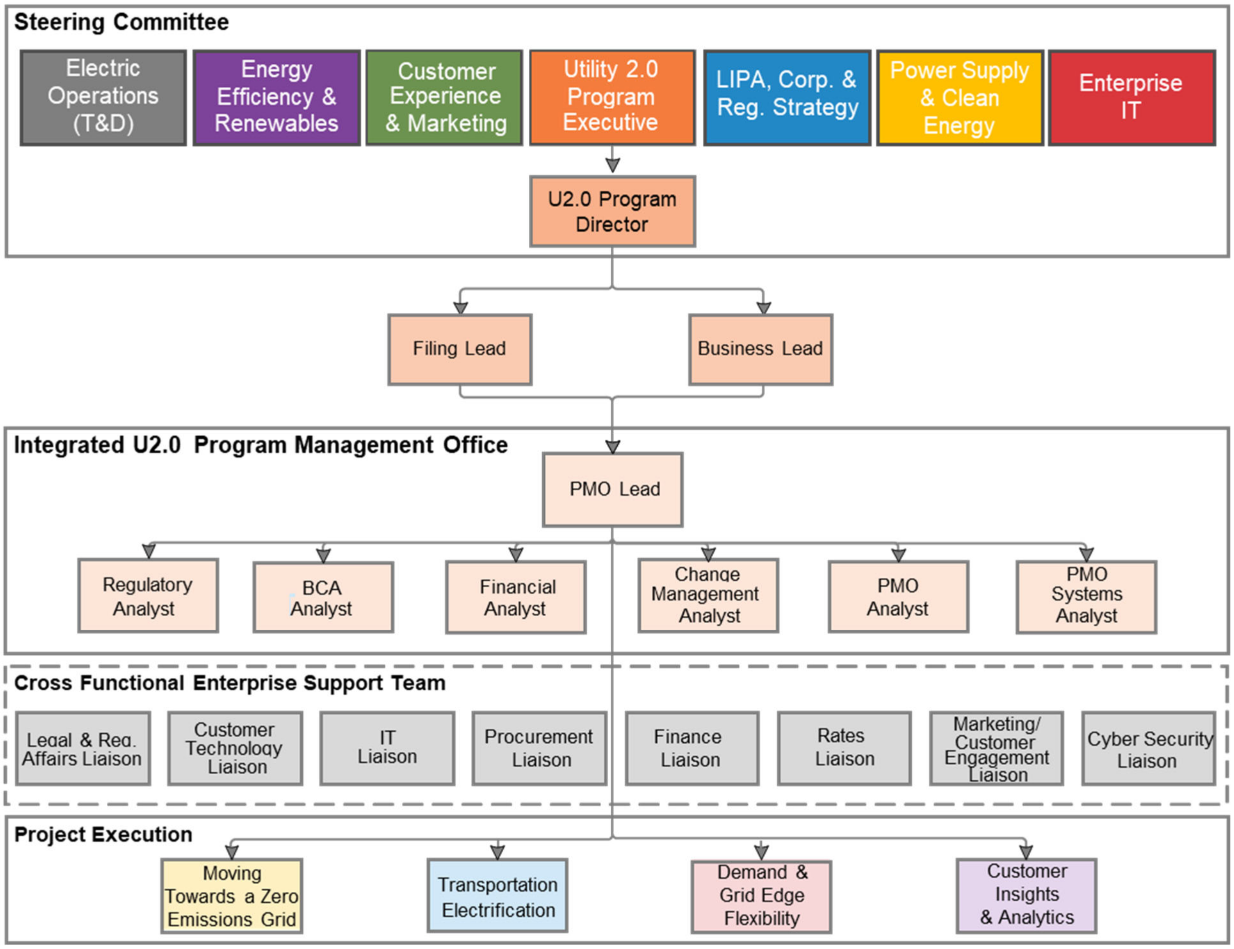
1.2 Managing the Utility 2.0 Program

PSEG Long Island's Utility 2.0 vision is realized through an enterprise-wide program that includes more than 30 initiatives with a total budget of more than $300 million. In 2021, the Utility 2.0 program had more than 20 active initiatives with an annual budget of approximately $120 million. These initiatives span multiple functional groups with considerable departmental interdependencies and regulatory oversight and impact the organization, its processes, and its technology.

Utility 2.0 Program Governance

PSEG Long Island has established a cross-functional Utility 2.0 Steering Committee to provide executive oversight of the progress of various projects and initiatives and to coordinate and share information across customer service, transmission and distribution (T&D), information technology (IT), and other key stakeholders (Figure). The mandate of the Steering Committee is to oversee and support the Utility 2.0 portfolio of projects, assist in the resolution of critical project issues, and provide guidance to ensure projects meet defined goals and objectives within budget.

Figure 1-3. Utility 2.0 Governance Structure



Note: Building Decarbonization and Envelope Improvements initiatives are managed outside of the Utility 2.0 Program and Delivering Benefits to Disadvantaged Communities is addressed at a program-wide level

Supporting the Steering Committee is the Utility 2.0 Program Management Office (PMO). The PMO is responsible for establishing an integrated standardized project lifecycle, implementing standardized processes and templates for the portfolio of Utility 2.0 initiatives, establishing a progress reporting system for key stakeholders, and delivering targeted support in areas such as business process design and change management to high value projects (Figure). Included in the scope of the PMO is the delivery and discussion of interim quarterly reports with LIPA and the DPS and facilitation of regularly scheduled Steering Committee meetings ensuring visibility across the program for key stakeholders.

Figure 1-4. Program Management Office Capabilities

Project Implementation Support as originally proposed in the 2018 Utility 2.0 Plan included business process-led transformation and change management, most heavily tied to advanced metering infrastructure (AMI) deployment, in addition to the launch of the PMO. While other AMI activities related to Project Implementation Support have concluded, the scope and reach of the Utility 2.0 PMO has grown each year since 2018 with the addition and expansion of initiatives. As a result, it is the PMO portion of the Utility 2.0 Project Implementation Support scope that will continue as part of core operations beyond 2022. Though the PMO may continue to support the implementation of Utility 2.0 projects in the future, the budget line item for Project Implementation Support will be referred to as PMO going forward.

PMO Update

At the recommendation of the New York DPS, PSEG Long Island produces a Utility 2.0 Outcomes Dashboard on a quarterly basis, which summarizes updates on the execution of ongoing Utility 2.0 initiatives. The dashboard highlights success stories and documents implementation challenges and lessons learned from the delivery of initiatives across the Utility 2.0 program.

Building off the formalized reporting templates and processes put in place in 2020, the PMO facilitated multiple training sessions, including Risk Management and Tableau dashboarding, and developed written procedures to support the quality and consistency of reporting deliverables through 2021. Additional support was provided to Utility 2.0 initiative managers through distribution of a program-wide organizational chart and defined list of roles and responsibilities. Additional project implementation support in 2021 was targeted on high value projects, such as the electric vehicle (EV) Make-Ready Program, Utility of the Future (UoF) team, Next Generation Insights pilot, and new time-of-use (TOU) rates.

PMO Funding Reconciliation

Capital spending through 2021 was on budget, whereas operations and maintenance (O&M) spend was not required in 2021. Forecasted O&M costs for 2021 and 2022 were reduced in light of the lack of need for O&M spend to date.

Table 1-1. PMO Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Total
Capital	1.64	1.99	2.03	2.14	**7.80**
O&M	-	-	-	-	**-**
Total	**1.64**	**1.99**	**2.03**	**2.14**	**7.80**

Transitioning Utility 2.0 Initiatives into PSEG Long Island Core Operations

It is fitting that the Utility 2.0 vision and framework is evolving at the same time a list of 13 initiatives proposed in the 2018 and 2019 Utility 2.0 Plans are completing their scope and objectives. The highest value of these being AMI Technology and Systems, which met 145% of its annual goal with over 367,000 meters installed in 2021. Other initiatives on this list were enabled by AMI deployment including targeted customer engagement, Revenue Protection, Customer Experience Tools, Data Analytics, Rate Modernization, and the PMO.

Many of these initiatives have ongoing budget requirements even though the original scope was met to maintain, support, improve and continue to operate services. As a result, these initiatives will transition to PSEG Long Island's core business operations and budget. Due to the Utility and LIPA's internal financial processes, the effective date for initiatives to be deemed operationalized is January 1, 2023. Within this Utility 2.0 Plan these initiatives have been labeled with a 2023 status of "operational."

Initiatives listed as operational in this Utility 2.0 Plan will transition from the Utility 2.0 Plan and the quarterly Utility 2.0 Outcomes Dashboards to core operations and base budget reporting starting in the first quarter of 2023. Performance tracking and reporting will only continue beyond 2022 for projects that are currently active in Utility 2.0.

Table 1-2 defines all project status designations assigned to Utility 2.0 initiatives in this Plan and in future external reports.

Table 1-2. Utility 2.0 Initiative Status Definitions

Status	Definition
Proposed	A newly requested initiative submitted via the annual Utility 2.0 Plan
Active	An initiative leveraging Utility 2.0 funding and fulfilling Utility 2.0 regulatory reporting requirements
On Hold	An initiative not currently spending Utility 2.0 funding or reporting activity
Operational	An initiative that has met its Utility 2.0 scope and is transitioning to PSEG Long Island core operations, including all 2018 AMI projects, which may require ongoing base budget funding and Utility 2.0 regulatory reporting
Complete	An initiative that has met its Utility 2.0 scope and does not require future Utility 2.0 or base budget but may require ongoing Utility 2.0 regulatory reporting
Canceled	An initiative with no future Utility 2.0 spending or activity to report

As the Utility 2.0 Program continues to grow and evolve, PSEG Long Island will adapt and enhance its PMO tools, templates, and processes including program governance, integrated project lifecycle support, budget oversight, risk and quality management, and project health and success reporting.

1.3 Long Island Supports the Achievement of Statewide Clean Energy Goals

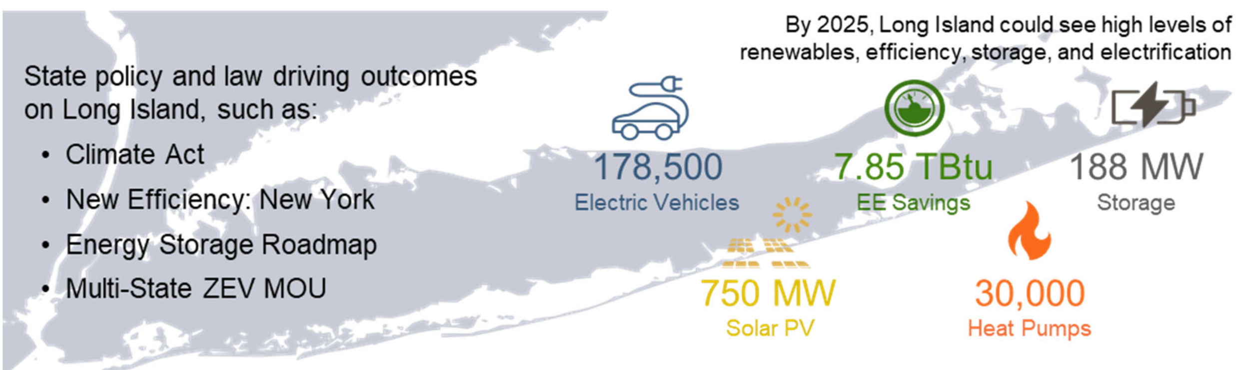
Long Island has a significant role to play in New York State meeting its Climate Act goals and additional policies that shape the State's energy and sustainability landscape. PSEG Long Island is contributing towards its share of these goals across several initiatives in the Utility 2.0 program.

PSEG Long Island also contributes to state goals through many of its long running Energy Efficiency (EE) programs, with an annual investment around $92 million for 2023. Further details around the EE programs the Utility is offering its customers and how they contribute to clean energy goals are included in the Energy Efficiency, Beneficial Electrification, and Demand Response (EEBEDR) Plan (Appendix A).

LIPA and PSEG Long Island are also supporting state clean energy goals in several ways that go beyond the initiatives included in the Utility 2.0 and EEBEDR Plans. Section 3.7 highlights some of these initiatives including utility-scale solar, wind, battery storage, and transmission planning.

Figure 1-5 shows Long Island's share of the statewide clean energy goals for 2025 based on PSEG Long Island's analysis.

Figure 1-5. Long Island's Share of the Statewide Clean Energy Goals for 2025[2]



Long Island's share of the statewide goals is based on the assumptions listed in Table 1-3.

[2] 2014 Multi-State Zero Emission Vehicle (ZEV) Memorandum of Understanding (MOU)

Table 1-3. Assumptions used to estimate Long Island's share of the Statewide Clean Energy Goals

Statewide Clean Energy Goal	2025	2030	Assumption(s)
Electric Vehicles	178,500 EVs	100% of new vehicles*	Based on Long Island's share of vehicle registrations in New York (approximately 21%)
Energy Efficiency	7.85 TBtu Savings	TBD**	Of the incremental target of 31 TBtu of reduction by utilities toward achieving the statewide goal, LIPA was assigned a proportional share of increased EE savings of at least 3 TBtu over the period of 2019-2025, or 7.85 TBtu when combining base-level electric savings and the incremental amount established in the December 2018 Order[3]
Energy Storage	188 MW	TBD**	Based on Long Island's share of statewide peak load (approximately 12.5%)
Heat Pumps	30,000 Installs (1.15 TBtu Savings)	TBD**	The basis for this was the 2020 annual EEDR Plan for that year's heat pump categories, with a reasonable growth rate across categories
Solar PV	750 MW DC	1,310 MW DC	Based on Long Island's share of statewide peak load (approximately 12.5%)

*This statewide clean energy goal is for 2035 rather than for 2030 and reflects only *newly sold* EVs. The 2025 statewide clean energy goal captures EVs *currently on the road*.

**Long Island's share of the statewide goals for 2030 for Energy Efficiency, Energy Storage and Heat Pumps are still to be determined by the state.

The Utility 2.0 initiatives underway or planned for the near future directly that contribute to energy efficiency (EE), energy storage, beneficial electrification (heating and transport), and renewable energy Climate Act targets specifically are identified in Table 1-4. Initiatives that yield prospective benefits for Disadvantaged Communities (Section 1.4) are listed in orange.

[3] Order Adopting Accelerated Energy Efficiency Targets, CASE 18-M-0084 In the Matter of a Comprehensive Energy Efficiency Initiative, December 13, 2018.

Table 1-4. PSEG Long Island Initiatives Contributing to New York State Clean Energy Goals

Category	Energy Efficiency	Heat Pumps	Energy Storage	Electric Vehicles	Solar PV
Statewide Goal for 2025	185 TBtu	5 TBtu	1,500 MW	850,000	6,000 MW DC
Long Island Portion of 2025 Goals	7.85 TBtu	30,000 installations (1.15 TBtu)	188 MW	178,500	750 MW DC
Actuals on Long Island (Q1 2022)	~3.55 TBtu	~13,780 installations (~0.51 TBtu)	~22 MW (3.78 MW queued)	~28,610	835 MW DC
Statewide Goal for 2030	TBD	TBD	6,000 MW[4]	TBD	10,000 MW DC[5]
Completed & On Hold Initiatives	• C&I Demand Alert Pilot		• BTM Storage with Solar Program		• BTM Storage with Solar Program • Hosting Capacity Maps 1-2 • IOAP Phase I
Approved Initiatives through 2022	• EE Programs (EEBEDR Plan) • Super Savers • Rate Modernization • Next Generations Insight	• EE Programs (EEBEDR Plan)	• Utility Storage – Miller Place • Energy Storage Bulk Solicitation • Rate Modernization • Connected Buildings Pilot	• EV Program • EV Make-Ready Program • Rate Modernization • Suffolk County Make-Ready Pilot	• DER Visibility Platform • Increasing Hosting Capacity Maps • Hosting Capacity Maps Stages 3
Proposed Initiatives (2023 Start)			• Storage Hosting Capacity Maps	• EV Hosting Capacity Maps	
Potential Future Initiatives (2024-2025 Start)	• EE Programs (EEBEDR Plan)	• EE Programs (EEBEDR Plan)	• Utility Storage (Further Locations) • Microgrid	• Utility Fleet Electrification	• DER Forecasting • Enhanced Distribution Modeling

Orange Text: Prospective Benefits for Disadvantaged Communities. Disadvantaged Communities and goals will be tracked in the future.

[4] 01Governor Hochul's 2022 State of the State Book [governor.ny.gov] (page 146)
[5] Governor Hochul Announces Expanded NY-Sun Program to Achieve at Least 10 Gigawatts of Solar Energy by 2030

1.4 Delivering Benefits to Disadvantaged Communities

The Climate Act also commits to supporting an equitable and just clean energy transition in New York recognizing that climate change impacts can disproportionately burden traditionally underserved communities. To ensure that New York State's clean energy policies deliver equitable benefits, the Climate Justice Working Group (CJWG) was formed to develop criteria for identifying these disadvantaged communities (DACs).

In March 2022, the CJWG released the draft criteria for public comment. The CJWG used 45 indicators to identify 35% of NYS census tracts as disadvantaged communities. Beyond the geographic criteria, one other criterion that was considered specifically for clean energy policy was total household income at or below 60% of State Median Income (SMI). This allows investments for individual households outside of census tracts identified as DACs making at or below 60% SMI to be included. The set of criteria for identifying disadvantaged communities is expected to be finalized in 2022.

Delivering benefits to disadvantaged communities is one of the six strategic priorities identified for 2023. PSEG Long Island is committed to developing programs, services, and other offerings to support and include Low-to-Moderate Income (LMI) and DAC customers and will continue to monitor Climate Act working groups. As the criteria is being finalized, PSEG Long Island has begun to identify enhanced incentives for EE, heat pump and electric vehicle that will target these customers and communities.

PSEG Long Island's 2023 EEBEDR Plan (7.3Appendix A7.3Appendix A) identifies opportunities to advance energy affordability for LMI consumers such as through heat pump rebates and programmatic changes designed to enhance the Home Performance and Residential Energy Affordability Partnership (REAP) programs that will total about $11 million in spending in 2023. The 2023 EEBEDR Plan also outlines how the Utility is consulting with its strategic marketing and advertising agency to support targeted outreach and increased awareness of EE programs to residential and business customers in DACs.

1.5 Looking Ahead to Multi-Year Filing in Future

PSEG Long Island's 2022 Utility 2.0 Plan is representative of a one-year outlook. The Utility intends to leverage the outcomes of several clean energy studies and plans that are still under development across the state to best inform their long-range strategy. Outcomes of the five outstanding initiatives listed below will be vital to ensure PSEG Long Island's future Utility 2.0 and EEBEDR Plans are setup for success. PSEG Long Island aims to deliver a 5-year Utility 2.0 Plan in 2023.

Disadvantaged Communities

As noted in the previous section (Section 1.4), the set of criteria for identifying disadvantaged communities is expected to be finalized by the CJWG later in 2022. The final criteria will enable PSEG Long Island to better understand the needs of customers located within each DAC.

Climate Action Council Scoping Plan

The Climate Action Council developed a Draft Scoping Plan to serve as a framework for how New York State will reduce greenhouse gas emissions, increase renewable energy usage, progress climate justice, and achieve net-zero emissions. The document outlines four potential scenarios for the State to reach its climate targets. Foundational themes across all scenarios are zero emissions in the power sector by 2040, expansion of transit and vehicle miles traveled reduction, widespread end-use electrification and efficiency, higher methane mitigation in agriculture and waste, and end-use electric load flexibility. The Climate Action Council will release a finalized scoping plan by the end of 2023.

LIPA's Integrated Resource Plan (IRP)

LIPA's 2022 IRP will examine the impacts of Climate Act requirements on supply and demand-side resources for electric power supply to Long Island and the Rockaways. The study will identify key actions and investments necessary to continue meeting customer electric needs reliably and cost-effectively which can then inform future Utility 2.0 or EEBEDR projects and initiatives. PSEG Long Island is developing the IRP on behalf of LIPA and is expected to issue the final report at the end of 2022.

Mid-term review of New Efficiency: New York[6]

DPS Staff will undertake a formal interim review of the programs, budgets, and targets authorized for New Efficiency: New York in 2022 for consideration by the Public Service Commission in 2023. The review will assess the full complement of authorized actions and make necessary adjustments in order to provide a mechanism to restate targets upwards, if more cost-effective potential is found, and to reflect direction setting that can emerge from the Climate Act.

State-wide Energy Efficiency and Building Electrification Potential Study

NYSERDA, in consultation with the Joint Utilities, Staff, PSEG Long Island, and LIPA, is undergoing a statewide EE and electrification potential study that is expected to be completed by the end of 2022. The study spans the most prominent fuel types (electricity, natural gas, oil, and propane), building sectors (small residential, multifamily, commercial, industrial), and customer segments. Each utility is currently working with NYSERDA to provide data in support of the study.

Energy Storage

New York State has some of the most aggressive energy and climate goals in the country, and energy storage will play a crucial role in meeting these goals. Energy storage helps integrate clean energy into the grid, increases system efficiency, provides hosting capacity to support integration of more renewables and DER, provides resiliency to keep critical systems online during an outage, and reliability where energy storage is used in place of traditional T&D investments. In 2018, New York State set a nation-leading goal of 1,500 MW of energy storage by 2025. Later that year, the New York Public Service Commission issued a landmark energy storage order establishing a goal of 3,000 MW of energy storage by 2030, and the deployment mechanisms needed to achieve the 2025 and 2030 energy storage targets. Based on the proportion of peak load compared to the entire State, approximately 188 MW should be installed in Long Island by 2025. Governor Kathy Hochul, on January 2022, called for New York to double its energy storage target to at least 6 GW by 2030 to help integrate significant new volumes of variable renewable energy resources.

PSEG Long Island supports the recommendations set in the New York Energy Storage Roadmap[7] ("Storage Roadmap"), specifically addressing the following areas: retail rate actions and utility programs, direct procurement approaches through NWAs, market acceleration incentive, and "clean peak" actions. At present, PSEG Long Island has a portfolio of energy storage initiatives that directly support the achievement of these statewide energy storage targets. As outlined in the Storage Roadmap, each of

[6] The New Efficiency:New York (NENY) report recommends a comprehensive mix of strategies to support customers and developers in pursuing improvements that reduce energy consumption.

[7] Department of Public Service. New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations. June 2018.

PSEG Long Island's initiatives addresses different use cases: distribution system, bulk system, and customer-sited.

Presently, PSEG Long Island is using two storage systems with a total capacity of 10 MW/80 MWh on the South Fork, soliciting for bulk energy storage to support the electric system in Long Island, and procuring a 2.5 MW utility-owned and operated energy system in Miller Place (Section 3.3).

Beyond utility-scale storage, customer-sited energy storage can support meeting the State's goals. PSEG Long Island completed its Behind-the-Meter Storage with Solar in 2021 (Section 5.2) and is proposing to make storage incentives available for Long Island residential customers through the new Residential Energy Storage System Incentive Program (Section 5.1). These projects directly support the Storage Roadmap's recommendation of leveraging market acceleration incentives to accelerate adoption of customer-sited storage, including pairing with PV.

PSEG Long Island will aim to pursue a least-cost storage portfolio, which will be informed by PSEG Long Island's Bulk Energy Storage RFP, the 2022 IRP and any updates to the Storage Roadmap.

2. Building Decarbonization and Envelope Improvements

The Climate Act puts the state on the path to reaching 100% zero emission electricity by 2040 and aims to reduce statewide greenhouse gas emissions by 85% by 2050 relative to 1990 levels. Given that buildings contribute about a third of the state's total direct carbon emissions, electrification, and energy efficiency upgrades in both new construction and existing buildings is key to achieving the decarbonization goals. Examples of key decarbonization strategies include high-performance building envelopes, energy-efficient technologies for heating and cooling buildings, and smart equipment promoting load flexibility.

Statewide, over 200,000 homes per year must be upgraded to be all-electric and energy efficient from 2030 onward and over 600,000 commercial, institutional, and multifamily buildings must rely on renewables by 2050.[8] To directly support building decarbonization, Governor Hochul committed to achieving a minimum of 1 million electrified homes and up to 1 million electrification-ready homes by 2030.[9] Of the 2 million, 800,000 of the homes are expected to be low- to moderate-income households.

PSEG Long Island has been actively engaged in rolling out utility-leading residential and commercial savings programs for customers outside of U2.0. The 2023 EEBEDR Plan (7.3Appendix A) focuses on continuing to deliver EE savings programs to residential and commercial customers, while expanding the Utility's efforts to include beneficial electrification initiatives. Adopting fuel-neutral savings targets allows PSEG Long Island to aggregate efficiency achievements across electricity, natural gas, and delivered fuels such as oil and propane, which requires a shift toward investments in non-lighting opportunities, especially an expanded focus on heat pumps and other beneficial electrification opportunities.

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[8] NYSERDA Carbon Neutral Buildings Roadmap: Achieving a carbon neutral building stock in New York State by 2050. June 2021.
[9] 2022 New York State of the State Book

3. Moving Towards a Zero Emissions Grid

Moving towards a zero emissions grid requires strategic planning to ensure customer energy demands are continuously met in parallel to deploying more renewables and battery storage to expand capacity. PSEG Long Island is moving towards a zero emissions grid through efforts and investments both within and outside of the Utility 2.0 program. Efforts focus on deployment of utility-scale renewables and storage, improving information available for developers to interconnect DER to the grid, and planning activities to ensure success in this trajectory towards a zero emissions grid in future years.

As detailed in Section 1.1, PSEG Long Island evolved its Utility 2.0 vision and framework to align with statewide priorities. The proposed Storage and EV Hosting Capacity Maps initiative supports Transportation Electrification in addition to *Moving Towards a Zero Emissions Grid*. The EV maps provide developers with insight on the optimal locations to build EV charging locations and, in turn, increase the accessibility of EV charging for customers. The storage maps similarly enable developers to understand optimal locations for additional storage and facilitate additional storage capacity.

To ensure a Distributed System Platform (DSP) capable of moving towards zero emissions, it is important to plan and operate a dynamic grid that encompasses DER and associated capabilities. The Utility of the Future team is foundational to supporting the overall advancement and management of the DSP, which enables proliferation of beneficial electrification, EVs, and Energy Storage across PSEG Long Island's service territory. The Utility Scale Storage project and planned implementation of energy storage at the Miller Place substation contribute to achieving energy storage targets.

Both the Hosting Capacity Maps and the Increasing Hosting Capacity Study provide guidance on how to enable higher DER interconnection within LIPA service territory. The Increasing Hosting Capacity Study is studying ways to enable the integration of DER specifically for locations that are currently or will be constrained, to ultimately yield more interconnection of zero emissions resources.

This chapter is organized into seven subsections that provide an update for Utility 2.0 or non-Utility 2.0 initiatives that directly align with the *Moving Towards a Zero Emissions Grid* priority area. PSEG Long Island notes that the initiatives in this chapter are not limited to only supporting this priority area and likely contribute to others.

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3.1 Proposed for 2023: Storage and EV Hosting Capacity Maps

2022 Status	Proposed
2023 Status	TBD
Start Year	2023
Funding Approved Through	N/A
Description and Justification	Building off Stage 3 Hosting Capacity Maps, the EV Hosting Capacity Map will provide information to the customer on favorable locations to site electric vehicle charging stations. The Storage Hosting Capacity Map will provide information on the amount of energy storage that can be interconnected at a particular location without resulting in adverse system conditions while also providing guidance to the interconnection customers on potential favorable locations that can accommodate energy storage. This project aims to be implemented in 2023, with applicable updates ongoing thereafter.

Building on the successful deployment of Stage 3 Hosting Capacity Maps in 2021 that provide location-specific information on where customers and developers can connect solar PV to the grid, PSEG Long Island is looking to implement both EV- and storage-specific hosting capacity maps.

Hosting capacity maps are circuit maps that provide information on the amount of DER that can be interconnected at a particular location without resulting in adverse system conditions. The objective of the Storage Hosting Capacity Map is to provide guidance to the interconnection customers on the potential favorable locations that can accommodate energy storage. Similarly, the EV Hosting Capacity Map will be hosted on the same platform and offer a high-level overview to customers on optimal locations for siting electric vehicle charging stations on the distribution system. The EV hosting capacity values will be calculated on the primary distribution system consistent with available distribution planning models.

The Storage and EV Hosting Capacity Maps will be published on PSEG Long Island's website as an informational tool for DER developers and customers. Additionally, the information on the Storage Hosting Capacity Map will be communicated through PSEG Long Island Interconnection Working Group meetings, similar to the Stage 3 Hosting Capacity Maps. Developers will be pointed to the EV Hosting Capacity Map through the EV website and informed of the maps via outreach by PSEG Long Island.

These maps will help facilitate storage integration and EV charging equipment deployment throughout PSEG Long Island's service territory. PSEG Long Island plans to build the Storage and EV Hosting Capacity Maps such that developers and customers can log into a single platform to see all available hosting capacity maps.

Key activities include:

- **Data collection and analysis:** PSEG Long Island will collect relevant data and conduct hosting capacity analyses for energy storage systems and load capacity analysis for EV charging locations.
- **Map development:** PSEG Long Island will develop the Storage and EV Hosting Capacity Maps based upon the analysis conducted. The Storage Hosting Capacity Map will be updated on a quarterly basis, consistent with the existing hosting capacity maps and the EV Hosting Capacity Map will be updated on an yearly basis.

Objectives

The objective of these maps is to provide guidance on the favorable location to interconnect storage or to site EV charging infrastructure on the LIPA distribution system.

Scope

PSEG Long Island plans to leverage the best practices of the Joint Utilities to develop the Storage and EV Hosting Capacity Maps. The color-coding of the storage map will be consistent with the color-coding scheme utilized for Stage 3 hosting capacity maps for solar.

PSEG Long Island expects that third-party support will be contracted to support development of the Storage and EV Hosting Capacity Maps. The technical analysis associated with both the Storage and EV Hosting Capacity Maps will be conducted by PSEG Long Island's internal Utility of the Future team with support from consultants. The maps will be made available on PSEG Long Island's website using the same portal as the existing Hosting Capacity Stage 3 Maps.

Functional Design Document
PSEG Long Island's IT team will work with the Utility of the Future team to build a design document that captures all the data and field requirements to fulfill the objectives of the Storage and EV Hosting Capacity Maps.

Framework Development
PSEG Long Island's IT team will develop the groundwork for the Storage and EV Hosting Capacity Maps, including building and testing a framework for LIPA system data to be represented on the maps.

Data Collection and Analysis
PSEG Long Island will work with third-party support to collect relevant data at the sub-feeder level and to conduct advanced hosting capacity analyses using EPRI DRIVE and CYME software for both the Storage and EV Hosting Capacity Maps.

Data Implementation
Data collected for both the Storage and EV Hosting Capacity Maps will be connected to the framework developed by the IT team. This phase of the project will include aligning data fields to the map framework and validating accuracy of data inputs.

User Acceptance Testing
PSEG Long Island will engage in user acceptance testing internally to validate the representation of EV and storage hosting capacity data represented in the maps.

Ongoing Updates to Map Data
PSEG Long Island's Utility of the Future team will be responsible for ongoing updates to the underlying data, including the storage hosting capacity values. Additional validation analyses may be conducted to ensure all data has been reviewed and updated based on the current system conditions. The Storage Hosting Capacity Maps is expected to be updated on a quarterly basis, and the EV Hosting Capacity Maps on an annual basis.

3.1.1 Implementation Plan

The Storage and EV Hosting Capacity Maps project will make progress concurrently on the functional design and framework development for the visual representation of the maps, and the data collection and analysis that will inform the maps. These two work areas will converge to including the data into the framework, testing the maps, and publishing the maps.

Schedule

The projected schedule for the Storage and EV Hosting Capacity Maps Project is provided in Table 3-

Table 3-1. Storage and EV Hosting Capacity Maps Project Schedule

Workstream	Q1 2023	Q2 2023	Q3 2023	Q4 2023	2024	2025
Functional Design Document						
Build Design Document						
Approve Design Document						
Framework Development						
Data Collection and Analysis						
Data Collection						
Sub-Feeder-Level Hosting Capacity Analysis						
Data Implementation						
Develop EV Load Maps						
Develop Storage Hosting Maps						
User Acceptance Testing						
Ongoing Updates to Map Data						

Known Risks and Mitigations

Table 3- identifies potential risks and mitigations for Storage and EV Hosting Capacity Maps.

Table 3-2. Storage and EV Hosting Capacity Maps Risks and Mitigations

Category	Risk	Mitigation
Project Scope	Need for communication with Joint Utilities on the current practices in building storage and EV hosting capacity maps, to ensure alignment in the development of PSEG Long Island's storage and EV hosting capacity maps	Build a cadence of communication with the Joint Utilities on the development of the storage and EV hosting capacity maps. Gain a full understanding of the scope of existing maps before beginning development of PSEG Long Island's storage and EV hosting capacity maps.

3.1.2 Funding Request

Request for capital and operating expenses for the proposed Storage and EV Hosting Capacity Maps are included below.

Capital Expenditure

Capital expenses required include third-party support and IT labor to build the web portal capability to show the Storage and EV Hosting Capacity Maps. Other capital expenses include technical consultant support, including for technical assumptions, load calculations, and circuit modeling. Internal labor provided by the Utility of the Future team will support the development and maintenance of the maps. PSEG Long Island anticipates that its experience in building its Stage 2 and Stage 3 Hosting Capacity Maps will inform an efficient and effective process to develop the Storage and EV Hosting Capacity Maps.

Table 3-3. Storage and EV Hosting Capacity Maps Capital Expenses

Funding Subcategory	Capital Expenditure ($M)			
	2023	2024	2025	3-Year Total
IT Labor	0.78	-	-	**0.78**
Materials & Equipment	0.03	-	-	**0.03**
PM, Labor & Training	0.46	-	-	**0.46**
Third Party Support	0.42	-	-	**0.42**
Other	0.23	-	-	**0.23**
Total	**1.93**	**-**	**-**	**1.93**

Operating Expenditure

Operating expenses are required once the maps are built to cover the costs for ongoing annual maintenance of the maps and web portal, including third-party verification of model accuracy and ongoing annual software/license costs. Labor costs related to the Utility of the Future team's maintenance of the maps are not included in this operating expenditure and are covered in the Utility of the Future team's separate operating expenses.

Table 3-4. Storage and EV Hosting Capacity Maps Operating Expenses

Funding Subcategory	O&M Expenditure ($M)			
	2023	2024	2025	3-Year Total
Materials & Equipment	-	0.03	0.03	**0.06**
IT Labor	-	0.01	0.01	**0.02**
PM, Labor & Training	-	0.01	0.01	**0.02**
Third Party Support	-	0.05	0.05	**0.10**
Total	**-**	**0.10**	**0.10**	**0.20**

3.1.3 Project Justification

The addition of the maps will expand the depth and accessibility of information to developers and customers interested in storage or EV charging development. The maps also build upon the already existing platform for the Stage 3 hosting capacity maps which optimizes the utilization of PSEG Long Island resources.

Additionally, the development of these maps will be vital to the growth and deployment of storage and EV charging infrastructure. By facilitating storage and EV charging infrastructure, these maps will help Long Island achieve its contribution to Climate Act goals.

Lastly, the Storage and EV Hosting Capacity Maps are capabilities that are emergent among peers, including utilities within the Joint Utilities of New York. PSEG Long Island intends to be in alignment with industry practices with the development of these maps.

Performance Measurement & Reporting

As a foundational customer-facing tool, the Storage and EV Hosting Capacity Maps are expected to provide value to Long Island customers or developers. The success is measured by ensuring relevant information is available to applicable customers and by ensuring the project stays on schedule and delivered by end of 2023. Information on the Storage Hosting Capacity Map will be communicated with interconnection customers through PSEG Long Island Interconnection Working Group Meetings. Additionally, developers will be pointed to EV Hosting Capacity Map through the EV website and informed of the maps via outreach by PSEG Long Island. The maps will provide guidance to the interconnection customers of the locations on the circuit for potential cost-effective storage and EV charging infrastructure deployment.

In order to effectively share information and drive engagement, the Hosting Capacity Maps will be presented within the context of the Make Ready program for customers, developers, and other interested parties to access for project planning purposes. Links to the tool will be posed within the EV section of www.psegliny.com/goelectric, on the make ready page and will be featured in business newsletters and communications.

3.2 Utility of the Future Team

2022 Status	Active
2023 Status	Operational
Start Year	2019
Funding Approved Through	2022
Description and Justification	The Utility of the Future team proactively drives the development of the electric grid in line with state policy objectives. The UoF team serves as one of PSEG Long Island's core business functions, supports incremental workloads associated with the development of the DSP, has completed several major initiatives such as the Locational Value Study and deployment of Hosting Capacity Maps and is currently working on a study to enable higher DER interconnection for constrained distribution circuits.

The objective of the Utility of the Future (UoF) team is to proactively drive the development of the electric grid in line with state policy objectives in the evolving New York regulatory environment. This effort is consistent with the PSEG Long Island business strategy to continue to align with the Climate Act and other New York State policy goals. The UoF team integrates infrastructure planning, identifies innovative distribution system projects, and makes strategic decisions towards moving towards the grid of the future.

The UoF team serves as one of PSEG Long Island’s core business functions. The team supports incremental workload associated with the development of the DSP. The UoF team utilizes AMI data to conduct analytical and voltage analysis on an as-needed basis, maintains and enhances the hosting capacity maps, participates in working groups such as the Market Design Integration Working Group (MDIWG), supports the Miller Place utility-scale distribution battery project, and also conducts special studies to enhance penetration of DERs on LIPA’s system. The team is also participating in Joint Utilities stakeholder sessions to leverage the best practices implemented by other members.

3.2.1 Implementation Update

See the scope and schedule updates below for Utility of the Future.

Scope Update

The scope of the Utility of the Future team remains as previously described.

Commitment to State Goals

The Utility of the Future team serves as a primary business function for PSEG Long Island and is proactively driving the development of the electric grid in alignment with state clean energy goals and policy objectives.

Schedule Update

The UoF team continues to deliver on its scope without schedule changes and the project will become operational beginning in 2023.

3.2.2 Funding Reconciliation

Due to the successful completion of several projects and tools, the Utility of the Future team will focus on operating and maintaining existing projects in 2022, and beyond, rather than implementing capital projects as initially reported in the forecast for 2022.

Table 3-5. Utility of the Future Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	0.26	0.30	0.32	0.05	**0.92**
O&M	0.17	0.33	0.85	1.13	**2.48**
Total	**0.43**	**0.63**	**1.17**	**1.18**	**3.40**

Table 3-6. Utility of the Future Capital and Operating Expense Variance

	2021	2022
Capital	(0.08)	0.33
O&M	(0.07)	0.08
Total	**(0.15)**	**0.41**

3.2.3 Performance Reporting

While not reporting benefits directly, in 2021, the UoF team continued to support DSP-related initiatives to continue to evolve towards a distributed system platform. UoF successfully delivered major projects on schedule such as Hosting Capacity Maps stage 1 and 2.

Lessons Learned

One of the lessons learned is that there is a greater need to advance technical analysis tools and knowledge to study the impact and operations of new technology such as DERs (PV, Storage, etc.) In addition, detailed technical studies need to be conducted to assess ways to integrate DERs, electric vehicles and renewables successfully onto the grid while maintaining system reliability and meeting Climate Act targets.

Next Steps

The responsibilities of the Utility of the Future team include delivering the 2023 proposed Energy Storage and EV Hosting Capacity maps project and maintaining and enhancing maps and tools the team has built since its inception to support the efficient development of the DSP. Additionally, the team will continue to utilize AMI data to support T&D planning processes and continue to review new initiatives that are required to advance the system in the future. As the team is integral to many core Utility 2.0 functions, it will continue its role when it becomes operationalized beginning in 2023.

3.3 Utility-Scale Storage – Miller Place

2022 Status	Active
2023 Status	Active
Start Year	2019
Funding Approved Through	2022
Description and Justification	In late 2019, PSEG Long Island issued a competitive solicitation for third-party support to deliver a 2.5 MW/12.5 MWh system at Miller Place Substation that, when delivered, will defer the need for costly grid infrastructure investments. Due to delays in procurement of the battery and the need date of the project changing from 2023 to 2024, a new quote is being obtained from the vendor. Despite procurement delays, the storage project is on track for completion.

Energy storage will play a crucial role in meeting New York's ambitious clean energy goals. In 2018, New York State announced a nation-leading goal of 1,500 MW of energy storage by 2025. Later that year, the New York Public Service Commission issued a landmark energy storage order establishing a goal of 3,000 MW of energy storage by 2030, and deployment mechanisms to achieve the 2025 and 2030 energy storage targets. Based on the proportion of peak load compared to the entire state, approximately 188 MW should be installed on Long Island by 2025.

To increase operational flexibility on the grid and to defer the need for costly grid infrastructure investments, PSEG Long Island's UoF team is continuously evaluating the need to deploy energy storage systems on the distribution grid. As of today, the only suitable location identified within the Utility 2.0 program is Miller Place. PSEG Long Island will continue to review and evaluate potential interconnection locations for energy storage projects as alternatives to traditional T&D solutions. These future projects will be proposed in future filings as applicable. PSEG Long Island also has a Utility-Scale Storage Program outside of Utility 2.0, as discussed in Section 3.7.1

3.3.1 Implementation Update

See the scope and schedule updates below for Utility-Scale Storage at Miller Place.

Scope Update

The scope, to develop an energy storage project of 2.5 MW/12.5 MWh at the Miller Place substation, remains as originally proposed.

Schedule Update

The Miller Place energy storage project is required to address thermal constraints in the area. The in-service date for the Miller Place battery is updated to 2024 due to lower than expected load additions in the area and by taking into account the feasibility of conducting additional load transfers to support during contingency conditions. PSEG Long Island also considered the anticipated timeline for battery procurement and construction based on ongoing discussions with the vendor and internal stakeholders. The battery will defer the need to install a substation transformer bank at Miller Place and will provide additional support required to supply the load during contingency scenarios. As of this update, the storage project is still on track to meet the projected in-service date of 2024.

Risks and Mitigations

Table 3-7. Risk and Mitigation Assessment – Utility-Scale Storage – Miller Place

Category	Risk	Mitigation
Schedule	Once PSEG Long Island receives a final supplier quote, it is valid for 30 days and requires timely approval from stakeholders to move forward.	Communicate supplier quote update with stakeholders in a timely and proactive manner

3.3.2 Funding Reconciliation

In the time that the project has been delayed, battery costs have increased significantly. This led to the requirement for a new vendor quote to reflect battery procurement costs in 2022 and the increased capital costs shown below. The increase in battery cost is attributed to the material cost increase associated with the battery technology (ex. cost of lithium).

O&M costs remain largely as previously forecasted.

Overall, the updated total forecasted spend is higher than the previously approved budget.

Table 3-8. Utility-Scale Storage – Miller Place Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Request 2023	Projected (Not Requested) 2024	Projected (Not Requested) 2025	Total
Capital	0.09	0.14	0.02	6.82	6.29	2.23	-	**15.60**
O&M	-	-	-	-	-	0.92	0.19	**1.11**
Total	**0.09**	**0.14**	**0.02**	**6.82**	**6.29**	**3.15**	**0.19**	**16.71**

Table 3-9. Utility-Scale Storage – Miller Place Capital and Operating Expense Variance

	2021	2022	2023	2024	2025
Capital	3.76	(1.43)	(3.47)	(2.23)	-
O&M	-	0.05	1.02	(0.92)	(0.19)
Total	**3.76**	**(1.38)**	**(2.45)**	**(3.15)**	**(0.19)**

3.3.3 Performance Reporting

No benefits were expected in 2021 for Utility-Scale Storage. PSEG Long Island will begin tracking KPIs and benefits when the storage system is implemented and operational in 2024. This project is expected to provide direct benefits, such as deferring the need to install a transformer bank at the Miller Place substation.

3.4 Hosting Capacity Maps Stage 3

2022 Status	Completed/Continuous Improvement
2023 Status	Operational
Start Year	2020
Funding Approved Through	2025

Description and Justification	Stage 3 Hosting Capacity Maps went live in Q4 2021 and were implemented to provide guidance to interconnection customers regarding the locations on the circuit for potential cost-effective DER deployment. The maps provide location specific information on distributed generation, for example the amount of PV capacity, that can be accommodated on the feeder.

Hosting capacity maps are a valuable tool to the deployment of DER onto the grid. These maps enable the achievement of New York State's Climate Act goals.

PSEG Long Island shares the Joint Utilities' vision to provide hosting capacity maps to DER developers and is leveraging some of the practices employed by the Joint Utilities to develop its own maps. Stage 3 maps provide granular location-specific information such as the amount of PV that can be connected at a particular location on the feeder.

Stage 3 Hosting Capacity Maps were implemented to provide guidance to the interconnection customers of the locations on the circuit for potential cost-effective DER deployment. Stage 3 maps were published on PSEG Long Island's website as an informational tool for DER developers and customers to facilitate DER integration throughout PSEG Long Island's service territory. Stage 3 maps help identify potential congested circuits in advance, providing insight on the capacity available to accommodate DER.

3.4.1 Implementation Update

See the scope and schedule updates below for Hosting Capacity Maps Stage 3.

Success Snapshot

The Utility of the Future team delivered and communicated the release of the Hosting Capacity Maps Stage 3 to the interconnection industry.

Scope Update

The scope remains as previously reported in the 2021 Utility 2.0 Plan.

Schedule Update

The schedule remains as previously reported in the 2021 Utility 2.0 Plan, with the Stage 3 Hosting Capacity Maps live as of Q4 of 2021 and updated quarterly.

3.4.2 Funding Reconciliation

The need for additional resources to complete the scope was reduced as IT utilized the platform developed in Stage 2 of the Hosting Capacity Maps to develop the Stage 3 Maps. External non-labor costs were minimized, and the Stage 3 Hosting Capacity Maps were delivered at the end of 2021 below the previously forecasted budget.

The O&M costs for the maps will come from core operations starting in 2023 as the platform used to publish the maps will be shared with other tools developed by PSEG Long Island, including the Storage and EV Hosting Capacity Maps. Future O&M will be conducted by internal IT and Utility of the Future teams and the project will no longer require Utility 2.0 budget beginning in 2023.

Table 3-10. Hosting Capacity Maps Stage 3 Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	-	-	0.01	-	**0.01**
O&M	-	-	0.15	0.27	**0.42**
Total	**-**	**-**	**0.16**	**0.27**	**0.43**

Table 3-11. Hosting Capacity Maps Stage 3 Capital and Operating Expense Variance

	2021	2022
Capital	1.69	-
O&M	0.34	0.16
Total	**2.03**	**0.16**

3.4.3 Performance Reporting

As a foundational customer-facing tool, hosting capacity maps are expected to provide value to a variety of PSEG Long Island stakeholders. The Stage 3 maps provide guidance to interconnection customers of the locations on the circuit for potential cost-effective DER deployment.

Lessons Learned

As the Stage 3 Hosting Capacity Maps were completed in 2021, remaining activity will be through quarterly updates of the maps. One of the lessons learned from the hosting capacity maps initiative is that the tool chosen to conduct the study must be flexible, to accommodate unique scenarios, and must be aligned with internal criteria or interconnection procedures to provide the most accurate hosting capacity results.

Driving stakeholder engagement and interaction with the Hosting Capacity Maps is another key focus area. Please refer to section 3.1.3 for the customer engagement approach.

3.5 Increasing Hosting Capacity Study

2022 Status	Active
2023 Status	Complete
Start Year	2022
Funding Approved Through	2023
Description and Justification	The Increasing Hosting Capacity Study analyzes the entire distribution system to identify circuits with thermal, voltage, and protection related constraints and associated DER penetration ratio on these circuits/substations. Additionally, this study explores specific solutions to enable higher penetration of DER for circuits identified to be most constrained. The study and delivery of the report is expected to be completed by the end of 2022.

PSEG Long Island is conducting a study throughout 2022 to understand opportunities to increase hosting capacity on 47 constrained distribution circuits and then to prioritize the locations and specific projects for increasing hosting capacity limits with respect to the largest need in terms of DER development activities.

The study analyzes the entire distribution system and identifies constrained distribution circuits with thermal, voltage, and protection related constraints based on the associated DER penetration ratio on these circuits/substations. The identified distribution circuits are being studied in detail to identify limiting constraints and prioritize specific solutions that can be implemented to enable higher penetration of DER at these locations.

The objective of this study is to prioritize the locations that are heavily constrained in terms of DER interconnection and to develop and prioritize cost-effective solutions that can be implemented to increase hosting capacity for heavily constrained circuits. Upon identifying the constraints, cost-effective solutions will be studied and prioritized to inform on next steps to increasing hosting capacity on the LIPA system.

Overall, the study is intended to help PSEG Long Island better understand the potential solutions and costs associated with increasing hosting capacity and to inform any next steps for how hosting capacity may be increased more broadly across the grid. This project is also consistent with the recommendations made in the New York Power Grid Study Report published by the DPS.

3.5.1 Implementation Update

See the scope and schedule updates below for the Increasing Hosting Capacity Study.

Scope Update

The scope of the project was updated to reflect the DPS recommendation to seek vendor quotes for solutions that the study prioritized.

Additional funding request is to seek consultant support to identify, evaluate, and provide cost estimates for the new technology that is currently being offered in the market to increase hosting capacity. Due to resources targeted toward completing the study, the onboarding of the consultant will occur in 2nd half of the year. The additional funding request will be used only if the consultant onboarded can complete the scope by the end of the year.

Schedule Update

The schedule of the project remains as originally proposed in the 2021 Utility 2.0 Plan, with completion of the study and delivery of the report expected by the end of 2022.

3.5.2 Funding Reconciliation

Forecasted 2022 O&M costs increased to reflect the additional consultant support discussed in the Scope Update above. No variance in the capital forecast is expected.

Table 3-12. Increasing Hosting Capacity Study Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	-	-	-	-	**-**
O&M	-	-	-	0.10	**0.10**
Total	**-**	**-**	**-**	**0.10**	**0.10**

Table 3-13. Increasing Hosting Capacity Study Capital and Operating Expense Variance

	2021	2022
Capital	-	-
O&M	-	(0.04)
Total	**-**	**(0.04)**

3.5.3 Performance Reporting

While there are no KPIs or Benefits to report related to the study, the projected findings align with climate change and renewable energy goals of Climate Act. These commitments include meeting aggressive renewable energy targets via the promotion of solar, storage, and wind technologies, including BTM installations by the Utility's customers and third-party developers.

3.6 CVR Program

2022 Status	Active
2023 Status	Complete
Start Year	2021
Funding Approved Through	2022
Description and Justification	The Conservation Voltage Reduction Program aims to reduce customer voltage to obtain energy savings on the distribution circuit. Field trials done in Q1 2022 at the Arverne substation have shown less need for capacitor bank installations and relocations than previously estimated. Additional studies will be conducted in the summer, during a period of annual peak load, to assess the potential benefits of implementing CVR.

The Conservation Voltage Reduction (CVR) Program aims to reduce customer voltage to obtain energy savings on the distribution circuit. Prior to 2022, field trials were conducted at the North Bellmore and Patchogue substations to assess the feasibility of implementing CVR on the LIPA system. For the North Bellmore and Patchogue field trials, the substation bus voltages were lowered to measure the energy savings from reduced voltages. The purpose of the field trial was to derive the conservation voltage reduction factor for the substation under study

For 2022, CVR program locations that were targeted were those with high penetration of AMI meters and with the least number of locations requiring voltage optimization. Based on this criterion, Arverne substation was selected to be evaluated for CVR implementation. The CVR Program will conclude at the end of 2022.

PSEG Long Island uses real time AMI data and reduces substation voltage to calculate the potential savings that can be achieved in the area. The CVR program involves upgrading, relocating, and possibly adding new capacitor banks to enable greater voltage optimization if feasible. The program also involves rectifying existing conditions where the voltage is already low on the secondary system when voltage optimization is conducted on the circuit.

3.6.1 Implementation Update

See the scope and schedule updates below for the CVR Program.

Scope Update

Field trials done in Q1 2022 at the Arverne substation have shown less need for capacitor bank installations and relocations than previously estimated. Based on the field trials conducted in Arverne for the first and second quarter, the energy savings in Arverne from voltage reduction have been negligible. Additional field trials will be conducted during the 2022 summer period in an attempt to see possibly larger energy savings due to higher loads in the summer. Should it be found that there are not benefits to implementing CVR at Arverne, the installation and relocation of capacitor banks or other voltage optimization mechanisms will not be pursued for this location.

Schedule Update

The schedule for the CVR Program remains as previously filed and remains focused on implementation and assessment of voltage optimization at the Arverne substation. The CVR Program is expected to be completed in 2022 and further funding will not be requested for the program beyond 2022.

3.6.2 Funding Reconciliation

Spending for the CVR Program in 2021 was approximately as estimated in the previous filing.

The current forecast for budget needs of the CVR Program in 2022 is less than previously filed, because the field trials at the Arverne substation showed less need for capacitor bank installations and relocations of existing capacitor banks.

Table 3-14. CVR Program Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Total
Capital	-	-	0.06	0.23	**0.29**
O&M	-	-	0.00	0.01	**0.01**
Total	**-**	**-**	**0.06**	**0.24**	**0.30**

Table 3-15. CVR Program Capital and Operating Expense Variance

	2021	2022
Capital	-	0.35
O&M	-	0.02
Total	**-**	**0.37**

3.6.3 Performance Reporting

Field trials are still being conducted at the Arverne substation to assess the modifications needed to implement CVR at the substation. Upon implementation of CVR, it is expected that the program will lead to energy savings on the distribution circuit.

Lessons Learned

The CVR Program is expected to be completed in 2022 and further funding will not be requested for the program beyond 2022. Key lessons learned from the CVR Program include a greater understanding of the voltage profile across the LIPA system. AMI voltage data has provided insight into the locations where the voltages might need to be optimized prior to implementing a system-wide CVR program. Additionally, this program enabled better insight into areas that need voltage improvements and also illustrated that LIPA's system is not a strong candidate for a CVR program. Since the CVR program focuses on reducing voltages, no other power quality issues have been observed or studied under the CVR program.

3.7 Outside of Utility 2.0: IRP, Large-scale Renewables and Storage and Long-Term Transmission Planning

Beyond Utility 2.0, PSEG Long Island has other efforts helping Long Island move towards compliance with the Climate Act: Utility Battery Storage, Long-Term Transmission Planning, Utility Scale Solar and Wind, and a 2022 Integrated Resource Plan. The Climate Act includes, among other mandates, a requirement that 70% of electricity consumed in the state by 2030 be produced with renewable energy (i.e., the 70 x 30 mandate), the development and commercial operation of 9,000 MW of offshore wind by 2035, 3,000 MW of energy storage by 2030, 6,000 MW of distributed solar by 2025, and 100% zero-carbon electricity production by 2040 (i.e., the 100 x 40 mandate). In addition, the Governor announced increases to some of those targets, although not formally adopted.

3.7.1 Utility Battery Storage

The Climate Act targets include a 3,000-MW statewide energy storage goal by 2030. This goal was preceded by a December 2018 New York PSC order establishing a 1,500-MW energy storage target for 2025. To date, LIPA has approximately 22 MW of energy storage connected to the system. LIPA intends to continue to contribute to New York State energy storage targets through existing energy storage projects under contracts with LIPA, new projects obtained through the 2021 Bulk Energy Storage System (BESS) request for proposals (RFP), distribution-level storage projects proposed in PSEG Long Island's Utility 2.0 Long Range Plan, as described above, and behind-the-meter (BTM) programs established in LIPA's Tariff for Electric Service, as described in Section 5.1.

The BESS RFP has a goal to obtain 175 MW of new bulk energy storage projects by 2025, although LIPA may select more or less than this goal depending on the cost-effectiveness of the proposals. This RFP is open to all energy storage technologies provided they are commercially viable and meet the required technical criteria, with a minimum size of 20 MW.

In the April 2022 State of the State address, the Governor proposed doubling of the State's energy storage goal to 6,000 MW by 2030. LIPA plans to issue additional Energy Storage RFP(s) in the next several years.

3.7.2 Utility Scale Solar and Wind

PSEG Long Island has been actively involved in the development of the first major offshore wind farm in the United States. Originally known as Deepwater Wind, this project, selected in the 2015 South Fork RFP, has been subsequently named South Fork Wind after the purchase of the project by a consortium of Orsted and EverSource. The project will deliver 132 MWs of renewable energy to the Long Island System. The target commercial operation date is September 30, 2023.

In addition to 91.2 MW of Utility Scale Solar already operating, in response to the 2015 Renewable RFP, PSEG Long Island recommended the selection of two utility scale solar projects. The Long Island Solar Calverton project, a 22.9 MW solar generation facility has an executed power purchase agreement and construction activities commenced in the winter of 2021-22 with commercial operation by the end of June 2022. On September 22, 2021, the LIPA Board authorized execution of the 36 MW Riverhead Solar 2 project power purchase agreement. Commercial operation is expected in late 2023.

To further support commercial solar development on Long Island, PSEG Long Island implemented four Feed-in-Tariff (FIT) programs which have 83.5 MW in operation, 5.3 MW in construction and 14 MW in award. This consists of: (i) FIT I starting in 2012, with 38.7 MW in operation, (ii) FIT II in 2013 with 30.3 MW in operation and 1.6 MW in construction, (iii) FIT III in 2016 with 14.4 MW in operation and 3.7 MW pending and (iv) In May of 2020 LIPA and PSEG Long Island launched a new Feed in Tariff program, termed Solar Communities or FIT V, with the first awards made in Q4 2020. Solar Communities is a new program to deliver affordable clean energy to income-eligible households, which have traditionally been underserved in the solar market. The new 20 MW Solar Communities program will nearly double the community solar market on Long Island. That program is still open for applicants.

3.7.3 Integrated Resource Plan (IRP)

While meeting New York State’s clean energy mandates poses challenges to all energy service providers, LIPA is in a unique position as a publicly owned and vertically integrated utility whose service territory is an island. LIPA has, over time, entered into a series of long-term power supply contracts and transmission agreement contracts with a variety of entities. Many of these contracts expire within the next ten years. Decisions on whether to renew, extend, or permit the expiration of the contracts, or enter into new contracts, are complicated by rapidly changing policy, legislative, and market developments.

LIPA’s 2022 IRP is a comprehensive assessment of LIPA's resource and transmission assets that will identify reliable, environmentally compliant, cost effective, and timely options for meeting future demand. The IRP commenced in June of 2021 and will help create a path forward for LIPA to comply with New York State’s clean energy and decarbonization goals. Further details can be found at https://www.lipower.org/irp/.

3.7.4 Behind-the-Meter Solar

The residential rooftop solar program accounts for over 500 MW of BTM solar generation. Since New York Sun funding ended in 2019, PSEG Long Island has consistently received and approved approximately 6,000 new BTM solar projects each year. The Utility has over 60,000 solar projects, reflecting about 6% of the customer base.

3.7.5 Long-Term Transmission Planning

PSEG Long Island conducts transmission planning studies for the ten-year planning horizon and identifies local transmission planning solutions that are needed to reliably serve customers. Local transmission planning is conducted in accordance with the New York Independent System Operator's (NYISO) comprehensive system planning process and local transmission planning criteria.

These studies mainly include but are not limited to power flow studies, fault duty assessment and transient stability studies, as required. Various other transmission planning assessments are conducted consistent with applicable requirements from the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC), in conjunction with NYISO processes to ensure the reliability of the Long Island transmission system.

On September 9, 2021, the NY PSC issued an order that continues the implementation of the Accelerated Renewable Energy Growth and Community Benefit Act (AREG-CBA)[10]. A specific commission order to develop a Coordinated Grid Planning Process (CGPP) was contained within along with eight other specific orders. The goal of the CGPP is to develop a planning process in coordination with both bulk system planning and distribution planning to identify and propose local public policy projects that proactively support Climate Act objectives. Additionally, the CGPP aims to produce a least cost transmission investment plan that considers the associated renewable resources being developed and produce the most cost-effective combination of local transmission and distribution upgrades and associated renewable energy resources. This process is under development and will help to advance NYS Climate Act objectives.

[10] New York Department of Public Service Case Number 20-E-0197: Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act

4. Transportation Electrification, Including Fleets

The transportation sector is the second biggest contributor of greenhouse gas (GHG) emissions in New York State. To achieve GHG reduction goals by 2050, the state has committed to:

- 850,000 electric light-duty vehicles by 2025
- All new passenger cars and trucks sold in NYS to be zero-emissions by 2035
- Electrifying the state's light-duty fleet and 100% of electric school buses by 2035
- All new medium-and heavy-duty (MDHD) vehicles to be zero-emissions by 2045

These transportation electrification targets are supported by initiatives that encourage wider adoption of electric vehicles. One key initiative is the statewide EV Make-Ready Program, which incentivizes greater deployment of EV supply equipment (EVSE) by providing funding to support customer-side make-ready infrastructure costs.

As detailed in Section 1.1, PSEG Long Island evolved its Utility 2.0 vision and framework to align with statewide priorities. All initiatives included in this chapter, including those implemented outside of the Utility 2.0 program, directly contribute to Transportation Electrification. The EV Make-Ready Program and the Suffolk County Bus Make-Ready Pilot support New York State goals to achieve a 40% reduction in GHG emissions from 1990 levels by 2030 and to deploy 850,000 ZEVs by 2025. PSEG Long Island's ongoing EV Program also promotes adoption of electric vehicles to help achieve the target of 850,000 EVs by 2025 as well as the all-new passenger vehicles being electric by 2035 target.

This chapter is organized into four subsections that provide an update for Utility 2.0 or non-Utility 2.0 initiatives that directly align with the *Transportation Electrification, including Fleets* priority area. PSEG Long Island notes that the initiatives in this chapter are not limited to only supporting this priority area and likely contribute to others.

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Note that the following Transportation Electrification project that was proposed in a prior Utility 2.0 Plan has been canceled and closed out of the program. Justification is provided below.

Electric School Bus Vehicle-to-Gide (V2G) Pilot

The Electric School Bus V2G Pilot was proposed to support the deployment of electric school buses to provide V2G services for PSEG Long Island and backup power to critical loads. The buses were expected to be used by Suffolk Transportation Services (STS) to transport children during the school year and then used by PSEG Long Island during the summer to address specific locational needs on the distribution network.

The Electric School Bus V2G Pilot was first proposed in the 2019 Utility 2.0 Plan with plans to launch in 2020. However, due to challenges with the electric bus design, concerns from the bus company stemming from the pandemic, and the school district's limited availability of funds, the pilot was suspended in 2020.

In 2021, the transit operator received grant funding that covered the replacement of 4 first generation EV buses along with the purchase of 7 incremental buses with associated chargers with V2G capability. PSEG Long Island discussed with Nuuve (Suffolk Bus' charging manufacturer) the potential for them to participate in PSEG Long Island's Value of Distributed Energy Resources (VDER) tariff when they are ready to discharge back to the grid. PSEG Long Island continues to remain in contact with the transit operator to understand their future fleet electrification plans and prepare to accommodate their projected power requirements.

Due to the aforementioned challenges, the Electric School V2G Pilot will not be pursued. The withdrawal of the previously authorized budget effectively terminated the project, and no additional work is expected on this effort in 2022 or beyond. Outside of this pilot, PSEG Long Island and its customers will continue to realize the benefits of transportation electrification through other PSEG Long Island initiatives.

4.1 EV Make-Ready Program

2022 Status	Active
2023 Status	Active
Start Year	2021
Funding Approved Through	2025
Description and Justification	The EV Make-Ready program was initially proposed in 2020 to support and accelerate EV adoption on Long Island. Over the next year, PSEG Long Island engaged a third-party EV expert consultant to develop an implementation plan that provides guidance on how to scale up the program through 2025. The scope and funding for the EV Make-Ready Program is revaluated in this filing based on the results of the implementation plan and includes additional charging points and the launch of a fleet electrification advisory service among other infrastructure investments.

In July 2020, the NY PSC released the EV Make-Ready Program Order (Make-Ready Order) that established statewide goals for a utility-supported EVSE Make-Ready (MR) program.[11] The Make-Ready Order recommends that major electric utilities should provide financial contributions for MR infrastructure to accelerate EVSE deployment, in turn enabling more rapid adoption of EVs.

In line with the proposed investments in the Make-Ready Order, PSEG Long Island proposed in its 2020 Utility 2.0 Plan a Phase 1 light-duty Make-Ready Program to support investment during 2021 in make-ready infrastructure for new direct current fast charging (DCFC) and Level 2 (L2) charging stations. PSEG Long Island also proposed in its 2021 Utility 2.0 Plan a Phase 2 light-duty Make-Ready Program to support EV make-ready (EVMR) investments from 2022 through 2025.

This Make-Ready Program builds upon PSEG Long Island's ongoing EV programs and is structured similarly to requirements set out in the Make-Ready Order. Due to accounting and financing nuances specific to LIPA's public power model, cash rebates are recovered through operating expenses and impact ratepayers in the year they occur. PSEG Long Island is therefore implementing a "lease-to-buy" model that will allow LIPA to capitalize on the customer-side make-ready (CS-MR) infrastructure for

[11] Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs, CASE 18-E-0138 Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure, July 16, 2020.

DCFC, thus avoiding having to recover a significant amount of operating expenses (for rebates for CS-MR infrastructure) from ratepayers.

4.1.1 Implementation Update

During the first quarter of 2021, PSEG Long Island engaged a third-party EV expert consultant to develop an implementation plan to identify target EVSE infrastructure levels, make-ready costs and associated incentives, and business models for make-ready and EVSE infrastructure deployment. This research provided guidance on how to scale up the EV Make-Ready Program through 2025.[12]

In the second half of the year, PSEG Long Island developed the Phase 1 program application form and terms and conditions and made key resources available to its customer web portal. Ahead of Phase 2 launch in 2022, PSEG Long Island also designed the end-to-end business process to support successful program implementation through clarification of the necessary activities, roles, and tools, as well as identifying key risks and improvement opportunities.

Scope Update

Overall, PSEG Long Island targets supporting the adoption of 178,500 EVs on Long Island through various transportation electrification initiatives. Long Island's share of the State ZEV adoption goal (850,000) is based on the ratio of vehicles registered on Long Island to those in the state, which is approximately 21%.

To directly support this goal, PSEG Long Island proposed in the 2021 Utility 2.0 Plan to make incentives available for 498 new DCFC ports and 4,247 new Level 2 ports through 2025. PSEG Long Island has since reevaluated annual program enrollments and budget requirements, as detailed in the following sections.

Ports
Based upon progress in both 2021 and early 2022, PSEG Long Island expects that enrollment in the Make-Ready Program will gradually increase over time.

Table 4-1 and
Table 4-2 show the total number of ports estimated to be enrolled and energized, respectively, by year and port type.[13] The total number of ports expected to be deployed through the program remains as previously proposed.

Table 4-1. EV Make-Ready Program Estimated Enrolled Ports by Type

Port Type	2021	2022	2023	2024	2025	Total
Level 2	16	250	450	1,000	2,531	4,247
DCFC	0	100	110	130	158	498
Total	**16**	**350**	**560**	**1,130**	**2,689**	**4,745**

The expected number of energized ports as shown in
Table 4-2 is based upon the assumption that Level 2 projects would take approximately six months on average from committing funds to construction and that DCFC projects would take approximately 15 months.

[12] Included as Appendix B in the 2021 Utility 2.0 Plan.

[13] Enrolled is defined as ports with committed funds or pre-approval letter. Energized is defined as the total population of DCFC and Level 2 ports that have meters set and put into service in a given year.

Table 4-2. EV Make-Ready Program Estimated Energized Ports by Type

Port Type	2022	2023	2024	2025	2026	Total
Level 2	204	400	863	2,148	633	4,247
DCFC	25	103	115	137	119	498
Total	**229**	**503**	**978**	**2,285**	**752**	**4,745**

The infrastructure targets are based on assumptions regarding the amount of infrastructure required to support New York State targets for EV adoption. Recognizing that actual EV adoption may vary from forecasts based on charging infrastructure availability, PSEG Long Island intends to monitor EV registrations in total and by EV type on an annual basis so that any deviations from forecasts can quickly be acknowledged and addressed. Depending on the types of deviation experienced (if any), PSEG Long Island would expect to identify the deviations and any resultant programmatic change to address as part of the annual Utility 2.0 reconciliation process in future years.

Infrastructure Costs

The make-ready costs are divided into two categories: Utility-Side Make-Ready (US-MR) and Customer-Side Make-Ready (CS-MR). Table 4-3 shows the infrastructure costs updated based upon actual average project cost data. Notably, the updated total make-ready infrastructure costs by port type are higher than previously estimated with CS-MR comprising the bulk of the costs.

Table 4-3. EV Make-Ready Program Infrastructure Costs per Location[14]

Port Type	US-MR	CS-MR	Total
Level 2	$2,100	$28,900	$31,000
DCFC	$22,000	$200,000	$222,000

Business Model

In the 2021 Utility 2.0 Plan, PSEG Long Island proposed a lease-to-buy model for all DCFC. In this model, LIPA would own all US-MR and CS-MR infrastructure and lease the CS-MR infrastructure to the customer over a ten-year period, after which the customer would own the CS-MR after the term of the lease. Since the 2021 Utility 2.0 Plan, PSEG Long Island experienced situations with DCFC projects where the avoided rebate cost is so small that it's not worth establishing a lease or the incentive is less than the US-MR cost. To address these issues, PSEG Long Island is proposing that the lease-to-buy model only be applicable for large DCFC projects with incentives above $50k. The rebate model, which is applicable for all Level 2 projects, would then be applicable for small DCFC projects (less than or equal to $50k).

In line with the model recommended by the DPS in its Make-Ready Order, for both Level 2 and DCFC infrastructure, the incentive strategy is a three-tier structure based on the relative value of a given port to the market. Projects will be eligible for an incentive equal to 100%, 90%, or 50% of costs depending on specific requirements based on power, location, technology, and other factors. The updated expected allocation of locations per incentive tier is shown in Table 4-4.

[14] Assumes 3 Level 2 ports and 4 DCFC ports per location

Table 4-4. EV Make-Ready Program Customer Incentive Breakdown (by location)

Port Type	100% Incentive	90% Incentive	50% Incentive	Total
Level 2	425	780	213	1,418
DCFC	13	39	78	130
Total	**438**	**819**	**291**	**1,548**

Schedule Update

PSEG Long Island finalized the implementation plan, program design, and funding process in 2021. Phase 1 of the program launched in mid-2021, and Phase 2 launched in early 2022.

The schedule to deploy infrastructure and incentives remains as previously proposed in the 2021 Utility 2.0 Plan —from 2021 through 2025—though the assumed amount of infrastructure planned to be deployed in each year varies. All aspects of program management and data collection will span the full duration of infrastructure and incentive deployment.

Risks and Mitigation

Table 4-5 outlines the potential risks and proposed mitigation steps for implementing the EV Make-Ready program.

Table 4-5. Risk and Mitigation Assessment – EV Make-Ready Program

Category	Risk	Mitigation
EV Adoption	Customers may adopt electric vehicles at a slower pace than the state targets require, despite the availability of sufficient charging infrastructure.	PSEG Long Island is offering a portfolio of electric vehicle programs (home charging, managed charging, outreach) to address barriers associated with electric vehicle adoption on Long Island.

4.1.2 Funding Reconciliation

Table 4-6 shows the updated project budget for the EV Make-Ready Program. Due to the shift in business model for small DCFC projects (i.e., rebate model) and reassessment of make-ready infrastructure costs (i.e., CS-MR comprising the bulk of total make-ready infrastructure costs), majority of the budget shifted from capital to O&M.

Table 4-6. EVMR Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Request 2023	Projected (Not Requested) 2024	Projected (Not Requested) 2025	Total
Capital	-	-	0.06	0.24	2.56	3.21	4.76	**10.83**
O&M	-	-	-	4.24	7.41	12.68	25.87	**50.20**
Total	**-**	**-**	**0.06**	**4.48**	**9.97**	**15.89**	**30.63**	**61.03**

Table 4-7. EVMR Capital and Operating Expense Variance

	2021	2022	2023	2024	2025
Capital	1.39	9.61	15.00	13.15	15.09
O&M	1.20	(1.25)	(1.41)	(5.75)	(17.06)
Total	**2.59**	**8.36**	**13.59**	**7.40**	**(1.97)**

The updated budget forecast for 2023 largely consists of the costs associated with make-ready infrastructure as discussed in detail in the “Scope Updates” Section above. At a high level, the capital expenses include US-MR costs for DCFC and Level 2 chargers and the CS-MR costs for large DCFC projects, which are capitalized and partially reimbursed through the lease payments (lease payments are not accounted for in the budget, as they will be realized as added utility revenue in later years). The operating costs include the make-ready incentives paid to developers to cover the Level 2 and small DCFC CS-MR costs.

The budget for program management (O&M) was increased to account for the costs of two additional FTEs responsible for overall implementation of the program. Instead of working with third-party contractors to manage the components of the program, PSEG Long Island proposes to leverage internal staff for the program.

To gain value from the large amounts of data associated with the program, PSEG Long Island proposed several IT-related investments in the 2021 Utility 2.0 Plan: EV Salesforce database, data aggregation, and data collection. Since the 2021 Utility 2.0 Plan, PSEG Long Island is no longer pursuing the EV Salesforce database and instead will leverage the existing LM Captures system, a software used to collect data in-house. PSEG Long Island still expects to procure a third-party contractor to be responsible for the data aggregation and work with the internal IT team to develop the process for automating data collection.

PSEG Long Island also proposed in the 2021 Utility 2.0 Plan to include Fleet Advisory Services within the scope of the EV Make-Ready Program. These services will be available to advise customers on site feasibility, rate analysis, cost savings and bill impacts, and optimized charging strategies. The increased budget for Fleet Advisory Services includes costs for a Full-Time Equivalent (FTE) to manage the program internally and for a calculator tool to better advise customers on cost savings.

Building on this program, PSEG Long Island is considering a similar make-ready infrastructure program for MDHD vehicles. Given the scale and multi-faceted aspects of the full-scale program, as well as uncertainties in the evolving statewide frameworks for MHDVs, PSEG Long Island is proposing to develop an implementation plan in the second half of 2022 that forecasts MDHD vehicle penetration, identifies target ports, charger requirements, costs and budget, and optimal business models. The study will focus on a variety of MHDVs, including the electrification of school buses and transit. The overall intent of this implementation plan is to build a foundation by incorporating learnings from the light-duty EV Make-Ready Program and determine MDHD-specific program elements that will support the development of a broader program.

4.1.3 Performance Reporting

Through Q1 2022, 62 Level 2 and 68 DCFC ports have enrolled in the EV Make-Ready Program. Due to the decrease in program costs as shown in Table 4-6, the updated SCT benefit-cost ratio is 1.45.
To calculate realized benefits and costs of the EV Make-Ready Program, PSEG Long Island will continue to track number of ports enrolled and energized, make-ready costs, utility funds committed, and overall EV adoption on Long Island.

4.2 Suffolk County Bus Make-Ready Pilot

2022 Status	Active
2023 Status	Active
Start Year	2022
Funding Approved Through	2025
Description and Justification	PSEG Long Island is supporting the EV Make-Ready infrastructure for Suffolk County's electric buses to better understand the needs, costs, and challenges of electrifying public MDHD transit fleets. The lessons learned through this initiative will be utilized to support and scale up future programs related to electrifying transit fleets in PSEG Long Island's service territory.

The proposed pilot goes beyond the scope of the EV Make-Ready Program, which is focused on electric charging infrastructure for light-duty vehicles, to explore Make-Ready infrastructure requirements for MDHD electric vehicles. Through this pilot, PSEG Long Island will work with Suffolk County to construct and contribute funds to Make-Ready infrastructure for two charging sites. The Make-Ready infrastructure deployed is expected to support the charging requirements of approximately 40 buses by 2025.

4.2.1 Implementation Update

See the scope and schedule updates below for the Suffolk County Bus Make-Ready Pilot.

Scope Update

The scope remains as previously proposed in the 2021 Utility 2.0 Plan.

Schedule Update

The schedule is shifted by approximately six months to account for delays in acquiring the electric buses. Suffolk County issued a solicitation to procure the busses and chargers and expects the buses to be delivered by Q3 of 2023, and the Make-Ready infrastructure is expected to be deployed and ready by the end of 2022. While the schedule is slightly delayed, PSEG Long Island still expects the pilot to be completed by end of 2023 as originally proposed.

Risks and Mitigations

Table 4-8 outlines the potential risks and proposed mitigation steps for this initiative.

Table 4-8. Suffolk County Bus Make-Ready Pilot Risk and Mitigation Assessment

Category	Risk	Mitigation
Technical	Charging infrastructure may not be sufficient for the planned bus routes and operation.	Coordinate with Suffolk County to confirm assumptions around charging requirements. An objective of the initiative is to assess this risk and implement learnings in future support.
Project Management	Delays in delivery of the electric buses would lead to project delays and underutilization of the make-ready infrastructure.	Build flexibility into the project schedule to accommodate delays.

4.2.2 Funding Reconciliation

The total updated budget is slightly less than the approved budget. The decrease is due to lower make-ready infrastructure costs expected at the two sites. Annual budget is shown in Table 4-9.

Table 4-9. Suffolk County Bus Make-Ready Pilot Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Request 2023	Projected (Not Requested) 2024	Projected (Not Requested) 2025	Total
Capital	-	-	-	0.10	-	-	-	**0.10**
O&M	-	-	-	0.71	0.04	-	-	**0.75**
Total	**-**	**-**	**-**	**0.81**	**0.04**	**-**	**-**	**0.85**

Table 4-10. Suffolk County Bus Make-Ready Pilot Capital and Operating Expense Variance

	2021	2022	2023	2024	2025
Capital	-	0.50	-	-	-
O&M	-	(0.30)	-	-	-
Total	**-**	**0.20**	**-**	**-**	**-**

4.2.3 Performance Reporting

Once completed, PSEG Long Island will assess the pilot hypotheses as proposed in the 2021 Utility 2.0 Plan.

4.3 EV Program

2022 Status	Active
2023 Status	Active
Start Year	2019
Funding Approved Through	2025
Description and Justification	The current EV Programs consist of outreach and marketing, a DCFC program, a Residential Smart Charger rebate program, and a Smart Charge Rewards program. Since launch in 2019, 77 ports have been energized, 3,583 customers have enrolled in the Smart Charge Rewards program, and 3,766 Smart Charger rebates were distributed to customers. Parts of the program will continue through 2025.

The EV Programs aim to enhance penetration of EVs on Long Island, align EV customer adoption strategy with reducing GHG emissions, empower customers, animate the EV charging infrastructure market, improve system efficiency, and deploy smart EV charging systems to encourage off-peak charging. The current EV Programs consist of Smart Charger Rebate, Smart Charge Rewards, and DCFC incentives.

4.3.1 Implementation Update

Since its launch in 2019 through end of 2021, 77 DCFC ports have been energized, 3,583 customers have enrolled in the Smart Charge Rewards Program, and 3,766 Smart Charger rebates were distributed to customers.[15]

Success Snapshot

Customers can easily access the Smart Charger rebates in the online marketplace and over 3,766 rebates were distributed to customers

Scope Update

The scope of the EV Program remains as previously reported in the 2021 Utility 2.0 Plan.

Schedule Update

The Residential Smart Charger Rebate Program and the DCFC Incentive Program are continuing as scheduled through 2025. Enrollment in the Smart Charge Rewards Program was open through end of 2021 with payouts continuing through the end of 2022, after which the program will close and EV owners will be encouraged to sign up for TOU rates.

4.3.2 Funding Reconciliation

The EV Program spent approximately $1.5 million in O&M in 2021. The spending was slightly less than planned, largely due to the lack of DCFC incentive payouts. The forecasted budget for 2023 is greater than the approved budget primarily due to increased costs associated with increased incentives available for DCFCs and data collection licensing.

[15] Smart Charge Rewards Program offer participants incentives when they use their qualified smart charger between the off-peak hours of 11 PM and 6 AM. Smart Charger Rebate Program offers participants a cash rebate with the purchase of a Level 2 Smart Charger.

Table 4-11. EV Program Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Request 2023	Projected (Not Requested) 2024	Projected (Not Requested) 2025	Total
Capital	-	-	0.06	0.24	2.56	3.21	4.76	**10.83**
O&M	-	-	-	4.24	7.41	12.68	25.87	**50.20**
Total	**-**	**-**	**0.06**	**4.48**	**9.97**	**15.89**	**30.63**	**61.03**

Table 4-12. EV Program Capital and Operating Expense Variance

	2021	2022	2023	2024	2025
Capital	-	-	-	-	-
O&M	0.13	(0.30)	(0.59)	(0.04)	(0.09)
Total	**0.13**	**(0.30)**	**(0.59)**	**(0.04)**	**(0.09)**

4.3.3 Performance Reporting

The metrics for the EV Program track the participation rates in the residential and public charging programs. For the residential programs, the number of participants is tracked via the number of Smart Charger rebates paid to customers. The participation in the public program is tracked as the number of DCFC ports committed. The take-rate is a key metric that combines the program participation with the total expected number of EVs sold and offers insight into the success of participant acquisition. The take-rate through 2021 exceed the target of 13% (Table 4-13). Similarly, the total number of participants in the residential programs was higher than expected.

Table 4-13. EV Program Performance KPIs

Metric	Target Through 2021	Realized Through 2021	Realized %
Program Take-Rate	13%	18%	N/A
EV's Sold on Long Island[16]	21,271	26,301	124%
Residential Smart Charger Rebate Program Participants	2,755	3,766	137%
DCFC Program Ports Committed	360[17]	196	48%
% of EV Charging Off-Peak	N/A	69%	N/A

The DCFC Incentive Program has met 48% of its five-year target. Participation in the Smart Charger Rebate Program continues to exceed expectations, and as a result allowed for all benefits to exceed targets through 2021, as shown in Table 4-14.

[16] Extracted from the NYSERDA Charge NY Electric Vehicle Registration Map filtered for PSEG Long Island: https://www.nyserda.ny.gov/All-Programs/chargeny/support-electric/map-of-ev-registrations.

[17] Target represents five-year target.

Table 4-14. EV Program Benefit Reporting

Benefit	Target Through 2021 ($M)	Realized Through 2021 ($M)	Realized %
Participant Benefit	2.10	2.41	115%
Added Revenue	3.36	4.06	121%
Avoided Fuel Emissions	0.77	0.94	123%

4.4 Outside of Utility 2.0: Electrification of PSEG Long Island Fleet

In the 2021 Utility 2.0 Plan, PSEG Long Island proposed procuring a third-party consultant to develop an implementation plan for purchasing an electric bucket truck to inform future programs aimed at electrifying the broader population of medium-and heavy-duty vehicles. Per DPS recommendations, instead of procuring a consultant, PSEG Long Island explored the potential for fleet electrification with internal experts.

PSEG Long Island determined that converting internal utility fleet vehicles is not appropriate at this time due to the following factors:

- **Nascent Market**: PSEG Long Island met with several bucket truck manufacturers to discuss potential available electric vehicles and found that the technology is still in the preliminary stages and is not expected to be available until at least 2024. PSEG Long Island will be evaluating light duty pick-up truck and SUV availability for 2023 and forward, as well as evaluating plug-in electric tractor and straight truck for warehouse delivery applications.

- **Existing Vehicles**: PSEG Long Island's existing fleet has not yet reached the end of their useful life. Typically, PSEG Long Island utilizes vehicles to the point where they are at or past the point of economic repair. PSEG Long Island will continue to monitor vehicle condition and operation to identify vehicles for electrification.

- **Suitability**: Initial designs of the electric vehicles were not determined to be suitable for PSEG Long Island. Specifically, PSEG Long Island found that range and cycle time and weight studies did not meet operation needs.

- **Unclear Infrastructure Needs**: As with all electric vehicles, charging infrastructure is required to allow charging of the vehicles when they're not being used. While a limited number of charging stations have been installed, a full-scale infrastructure campaign would be required to support any large-scale vehicle acquisitions. PSEG Long Island will continue discussions with its landlord to assess feasibility.

PSEG Long Island will continue to monitor progress of the electric bucket truck technology and plans to reassess suitability for its needs once technology has matured.

5. Demand and Grid-Edge Flexibility

Driven by the electrification of buildings and transportation, New York's clean energy future will see gradual increases in load on the electric system. These load increases, in addition to increased renewable energy integration, will ultimately require the electric system to be more flexible to accommodate 100% carbon-free electricity. Historically, demand response (DR) programs required customers to make active behavior changes in response to peak events. Demand flexibility, on the other hand, allows for real-time shifting of behind-the-meter resources.

Some examples of demand and grid-edge flexibility initiatives include energy storage and non-wires alternatives (NWA). Energy storage helps integrate clean energy into the grid, increases system efficiency, provides hosting capacity to support integration of more renewables and DER, and provides resiliency to keep critical systems online during an outage. NWAs allow for avoiding or deferring traditional T&D investments by using alternative solutions such as energy storage, renewable energy, EE, and DR. They can deliver cost savings to customers and achieve system-wide and localized benefits (e.g., environmental).

As detailed in Section 1.1, PSEG Long Island evolved its Utility 2.0 vision and framework to align with statewide priorities. Initiatives included in this chapter contribute to *Demand and Grid-Edge Flexibility* in different ways. For example, the BTM Storage with Solar Program and the proposed Residential Energy Storage System Incentive Program promote adoption of storage. The latter is uniquely capable to support DERs by storing solar generation and utilizing it during critical peak demand periods.

The Connected Buildings Pilot aims to deploy smart electric panels within residential buildings for ease of integrating energy storage and solar PV, as well as insight into circuit-load energy usage, resulting in contributions to the state's solar and storage goals. The DER Visibility Platform increases distribution system operational capabilities as DER are added to the distribution grid, which in turn enables the safe and effective addition of DER. And the Locational Value Tool estimates the value that is used to defer T&D capital investment, which is needed to incentivize the interconnection of DER within PSEG Long Island's service territory. The values derived from the tool are used as inputs to NWA Planning Tool to assess NWA solutions for the traditional proposed capital projects.

The NWA Process Development program and Planning Tool promote NWAs which animate customer measures and markets as an alternative to traditional utility construction. These initiatives promote the identification, selection and procurement of NWAs and enable PSEG Long Island to calculate system benefits and costs more comprehensively. The Super Savers program in North Bellmore and Patchogue is an example of an NWA already deployed in PSEG Long Island's territory.

The Rate Modernization initiative included in this chapter is foundational to all priority areas, specifically grid-edge flexibility, by encouraging customer energy patterns that are beneficial to load balancing efforts and by providing customers with greater choice and convenience. By promoting load shifting through TOU rates, PSEG Long Island can encourage lasting customer behavioral changes that can reduce overall supply and delivery costs to all customers and protect the integrity of existing infrastructure by reducing peak load usage. Rate Modernization provides additional incentives for customers to purchase electric vehicles, energy storage, heat pumps, solar PV as well as participation in other energy efficiency and demand response programs.

This chapter is organized into nine subsections that provide an update for Utility 2.0 initiatives that directly align with the *Demand and Grid-Edge Flexibility* priority area. PSEG Long Island notes that the initiatives in this chapter are not limited to only supporting this priority area and likely contribute to others.

Chapter Contents

5.1 Proposed for 2023: Residential Energy Storage System Incentive

2022 Status	Proposed
2023 Status	TBD
Start Year	2023
Funding Approved Through	N/A
Description and Justification	PSEG Long Island is seeking to carry on the existing state-supported incentive program that provides residential customers with financial support for purchasing and installing BTM energy storage systems paired with solar. This initiative will be an extension of NYSERDA's NY Sun Retail Energy Storage Incentive Program and will commence directly after current NYSERDA funding expires expected in Q3 2023.

PSEG Long Island proposes an incentive program to provide customers with financial support for purchasing and installing energy storage systems (ESS). The upfront incentives will be available for PSEG Long Island residential customers (including LMI) installing ESS paired with new or existing solar.

This program proposes to continue leveraging NYSERDA's existing Long Island Single-Family Residential Energy Storage Incentive program.[18] The program will continue utilizing NYSERDA's terms and conditions set out in the Program Manual and Energy Storage Participating Contractor base. PSEG Long Island expects to make available the additional funding once the current incentive block expires.

Incentives provided will leverage participation in the BTM Storage plus Solar Demand Response program by requiring enrollment prior to payment. Approved in the 2018 Utility 2.0 Plan, the 10-year tariff program helps accelerate the residential storage market by providing participants reservation and performance compensation and helps alleviate system peak demand load.

The funding is also expected to be made available to LMI customers in Long Island who could benefit the most from cost savings but are typically the last to gain access to them. As a result, PSEG Long Island is considering increased incentives for qualified LMI customers (see in the "Scope" Section).

PSEG Long Island proposes an additional $2 million in incentives are made available through this program. The funding is expected to be placed in a declining Block incentive structure based upon a system's usable installed capacity (kWh).

[18] https://www.nyserda.ny.g Webov/all-programs/energy-storage/developers-contractors-and-vendors/retail-incentive-offer

Objectives

The objective of the Incentive Program aligns with state priorities and regional commitments. The Climate Leadership and Community Protection Act (CLCPA) signed into law in July 2019 to address climate change and reach net zero emissions in New York State. The Act sets the goals to reduce emissions to 40% below 1990 levels by 2030 and then to 85% below 1990 levels by 2050.

The Energy Storage Roadmap, developed by the DPS and NYSERDA was released in June 2018, and set forth recommendations to build a sustainable, market-driven energy storage sector which called for programs that stimulate third-party investment alongside public and utility investments that help spur the pace of cost reductions.

In July 2019, New York State announced funding to support a collaboration between NYSERDA and PSEG Long Island to support Solar-Plus-Storage Deployment with $55 million for energy storage for commercial and residential storage projects on Long Island with an initial rollout of nearly $15 million from NYSERDA.[19] The announcement stated that Energy storage projects supported by this Long Island initiative will advance progress toward achieving New York's target of 3,000 megawatts of energy storage deployed by 2030. The $15 million was committed through NYSERDA's NY Sun Energy Storage Incentive Program and the remainder of the $40 million funds was to be allocated within three to five years and targeted in a manner to drive down costs and scale up the market.[20]

NYSERDA and PSEG Long Island jointly launched a residential solar-plus-storage program that provided new residential energy storage systems on Long Island with an upfront incentive via NYSERDA's NY-Sun Program. Incentive Block 1 of the program provided $4 million in up-front incentives for approximately 1,200 systems with a total of 850 customers, while Incentive Block 2, which is currently funded at $3 million, will provide for an additional 600 customers with a total of 950 systems.

Providing additional funding to support customer incentives will directly promote adoption of energy storage in Long Island by helping to lower the upfront cost of purchasing and installing battery storage. PSEG Long Island found that the attachment rate, defined as the rate at which residential solar applications to the NYSERDA NY Sun program also included battery storage systems, increased significantly from 1% in 2019 to 10% in 2022. The attachment rate is expected to further increase with the proposed additional incentive blocks.

In a December 2021 announcement, LIPA and New York State Solar Energy Industries Association (NYSEIA) agreed on a roadmap to develop a modern standard residential rate for electric customers on Long Island. In that agreement LIPA committed to fund an additional "declining block" of incentives for residential solar projects paired with an energy storage system that participate in LIPA's Dynamic Load Management program.

Scope

PSEG Long Island proposes making an additional $2 million in funding available through this program starting in Q3 2023. The funding will be placed in a declining Block incentives structure based on a per kWh of usable installed storage capacity. For this program, PSEG Long Island proposes two blocks with each block consisting of $1 million. The incentives will be available to PSEG Long Island single-family residential customers, with higher incentives proposed for LMI customers.

The first Block will offer $200 per kWh installed capacity (capped at $5,000 per project with a 25-kWh limit) for non-LMI customers and $400 per kWh for LMI (capped at $10,000 per project). The second

[19]Governor Cuomo Announces $55 Million for Energy Storage – Including Commercial and Residential Storage Projects – on Long Island, NYSERDA 2019 Report

[20]New York’s Regional Greenhouse Gas Initiative Operating Plan Amendment for 2021. NYSERDA. 2021.

Block will offer lower incentives: $150 per kWh and $300/kWh for non-LMI and LMI customers, respectively. Table 5-1 shows the proposed Block incentives.

Table 5-1. Residential Energy Storage System Incentive Program Incentive Rates by Block

Block	Available Funding	Non-LMI	LMI
1	$1,000,000	$200/kWh	$400/kWh
2	$1,000,000	$150/kWh	$300/kWh

Based upon the declining Block incentives structure, PSEG Long Island expects to enroll a total of approximately 850 systems through the program, assuming a battery capacity of 13.5 kWh/5kW. Table 5-2 outlines expected systems by customer segment and block.

Table 5-2. Residential Energy Storage System Incentive Program Expected Enrollment by Block

Segment	Block 1	Block 2	Total
Non-LMI	363	484	847
LMI[21]	4	5	9
Total	**367**	**489**	**856**

In order to be eligible for the incentive, storage systems must be paired with PV solar and meet the following requirements:

- Be permanently installed
- Be new and commercially available
- Be certified to UL 1973 and UL 9540 specifications by the time of installation
- Meet all AHJ requirements
- Be warrantied for at least 10 years
- Maintain a minimum 70% round-trip efficiency during the system life

Additionally, customers must also enroll their systems in the PSEG Long Island Dynamic Load Management (DLM) Tariff program to be eligible for the upfront incentive.[22] PSEG Long Island will encourage these participants to enroll in the Time of Use (TOU) rates but will not be required as a condition of being eligible for the upfront incentive. DLM participants receive performance incentive payments every year based upon the average measured load relief the battery contributes to the grid during critical periods.

As with NYSERDA's Incentive Blocks 1 and 2, PSEG Long Island will work directly with NYSERDA-approved solar contractors and developers to help offset the cost for installing ESS. Customers will need to work with a NYSERDA-approved participating contractor in order to receive the incentives, which is provided directly to the contractors. Contractors will install the system and must enroll the systems in PSEG Long Island's DLM Tariff program and commit to actively participate for a minimum of five years. Systems must also have at least 80% of usable capacities available for dispatch during the PSEG Long Island Energy Storage Rewards program capability period.

[21] 2% of total systems expected to be LMI; based upon battery storage systems enrolled through the NYSERDA Long Island Single-Family Residential Incentive for PSEG Long Island residential customers

[22] While all systems enrolled in the new Residential Storage Incentive Program must enroll in the DLM tariff to be eligible for the incentive, not all systems enrolled in the DLM tariff participate in the incentive program.

5.1.1 Implementation Plan

The Residential Energy Storage System Incentive Program aims to make funding available by Q3 2023, when the current NYSERDA Incentive Block 2 is expected to expire. Although projected to be fully subscribed by mid-2023, it is possible that the funding remains available for a longer period of time than expected. PSEG Long Island, therefore, proposes to make the additional funding available once the current incentive block expires. The following sections describe the tentative projected schedule of activities.

Schedule

The implementation plan consists of two main steps:

1. **Program Design and Setup:** PSEG Long Island will start working on finalizing program design and coordinating with NYSERDA on leveraging the existing customer enrollment platform. Once program design is finalized, PSEG Long Island will conduct customer outreach to promote the incentive program.

2. **Launch Solicitation:** PSEG Long Island expects to launch the first block of incentives in Q3 2023. On an ongoing basis, PSEG Long Island will be responsible for program and incentive management.

Table 5-3. Residential Energy Storage System Incentive Program Project Schedule

Workstream	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Program Design and Setup								
NYSERDA Coordination								
Finalize Program Design								
Launch Solicitation								
Marketing and Outreach								
Enroll Customers								
Ongoing Program Administration								

Customer Engagement and Communications

The customer engagement approach for the Residential Energy Storage System Incentive Program will be a multimodal strategy. Upon project approval, a detailed customer engagement plan will be developed. The objective of the plan will be to inform customers about the new incentive program, primarily focusing on incentive funding availability and new incentive structure and eligibility requirements.

Marketing efforts will focus on outreach to contractors and potential customers to identify participants who may have a propensity to install battery storage alongside a new solar installation. The engagement plan will include but not be limited to the following components:

- **Website**: Promote the new program on its website by making edits and updating the existing battery storage page to include information for the new program.
- **Digital/Printed Brochures / Billing Inserts**: Design and develop billing inserts and digital brochure that can be printed later for use by distributors to generate contractor interest.

- **Press Releases**: Generate press releases to provide information on where to find more details on the program.
- **Social Media**: Launch digital campaigns that will target potential energy storage program participants, such as LMI customers and customers with existing battery storage systems installed but not enrolled in the PSEG Long Island battery storage program.
- **Email**: Send out email blasts to inform PSEG Long Island residential customers of new storage incentive program.
- **Search Engine Optimization**: Implement Search Engine Optimization to promote the new storage incentive program web portal.

Known Risks & Mitigations

Potential risks and mitigations for the Residential Energy Storage Incentive Program are identified in Table 5-4.

Table 5-4. Residential Energy Storage System Incentive Program Risk and Mitigation Assessment

Category	Risk	Mitigation
Schedule	Although PSEG Long Island anticipates the current NYSERDA Incentive Block 2 to be available until Q2 2023, it is possible that the Block 2 incentive will be fully subscribed earlier, leading to delays in making available the proposed additional funding.	Track progress of NYSERDA Incentive Block closely to update projections and coordinate with NYSERDA on a regular basis ahead of launch. Extend NYSERDA funding by decreasing the incentive level ($/kWh) to increase the number of customers participating.

5.1.2 Funding Request

Request for capital and operating expenses for the proposed Residential Energy Storage System Incentive are included below.

Capital Expenditure

There is no capital expenditure associated with the proposed program.

Operating Expenditure

PSEG Long Island is requesting O&M funds for upfront customer incentives and marketing efforts (see the “Customer Engagement and Communications” Section for details on customer outreach plan).

Table 5-5. Residential Energy Storage System Incentive Operating Expenses

Funding Subcategory	O&M Expenditure ($M)			
	2023	2024	2025	3-Year Total
Customer Incentives	1.00	1.00	0.00	**2.00**
Marketing & Outreach	0.20	0.00	0.00	**0.20**
Total	**1.20**	**1.00**	**0.00**	**2.20**

5.1.3 Project Justification

The two subsections below detail the benefit cost analysis (BCA) along with the performance measurement and reporting metrics developed for the Residential Energy Storage System Incentive Program.

Benefit Cost Analysis

Benefit streams considered include net non-energy benefits, avoided outage costs, avoided energy (LBMP), avoided generation capacity cost (AGCC), avoided transmission capacity infrastructure, and avoided distribution capacity infrastructure. The benefits are largely driven by avoided outage costs, which consider the avoided costs associated with acquiring a home backup generator in the event of an outage. The analysis assumed that approximately 850 systems would enroll in the program and contribute to benefits.

Program costs include program administration costs and participant DER costs. The participant DER cost represents the majority of total program costs, consisting of the hardware and installation cost of the storage system.

Based on the above, the proposed Residential Energy Storage System Incentive Program has a societal cost test (SCT) benefit-to-cost ratio of 0.39. The largest driver of this result is the participant costs of the systems, as described in Section 3, the hardware and installation costs of energy storage systems remain high. For example, in 2018 when PSEG Long Island filed the original BTM Storage program (see Section 5.2), battery storage costs were approximately $500/kWh by 2022; however, actual program enrollment data shows that system costs are presently $950/kWh on average.

Although this may not appear favorable, PSEG Long Island believes that the overall business case is strong. Specifically, this program will ensure the following:

- **Statewide Clean Energy Targets:** Supporting statewide energy storage targets of 1,500 MW by 2025 in NYS and 188 MW by 2025 in Long Island

- **Leveraged Investment:** Stimulating third-party investment alongside public and utility investments and promote market competition at scale

- **Upfront Financing Support**: Removing barriers to energy storage adoption due to soft costs

Additionally, battery storage offers many non-energy benefits that are not presently assigned an economic value so by default they are valued at zero in the benefit-cost analysis. Examples of potential non-energy benefits include, but are not limited to[23]:

- **Property values**: Increased property values due to added resiliency and increased leasable space
- **Avoided safety-related emergency calls**: Reduced risk of emergencies associated with power outages
- **Job creation**: Creates jobs in engineering and research & development among others
- **Less land used for power plants**: Makes available land for other uses besides peaker plants

Furthermore, energy storage is a unique technology that can reduce peak demand or peak shifting on demand that cannot be effectively achieved with traditional, passive efficiency measures, but it can be achieved with battery storage. As more renewables come onto the electric grid, the ability to shift peak loads becomes more important and valuable. As solar generation begins to decline in the early evening hours, there is a drop in energy supply, however, demand for electricity continues to increase due to customers coming home from work and turning on their air conditioners and other appliances. This will be exacerbated by accelerated deployment of electric vehicles which if left unmanaged, will further increase

[23] Clean Energy Group. Energy Storage: The New Efficiency. April 2019.

peak demand. It remains to be important that PSEG Long Island deploy battery storage technology for peak shaving capabilities before this becomes an issue.

With a diverse fuel mix, New York State also suffers from what's called the "tale of two grids"[24], meaning that the fuel mix in upstate New York is much cleaner than the fuel mix in New York city and Long Island. Upstate New York consists mainly of hydropower, wind and solar, where Long Island and New York City hosts the majority of fossil fuel generation in the state. Deploying battery storage paired with solar for peak shaving capabilities will reduce the need for fossil fuel peaker plants on Long Island. Although not reflected in the BCA, this also results in greater environmental benefits through reductions in greenhouse gas emissions due to the fact that battery storage is reducing the need for dirty, peaker plants to operate as often on Long Island. These peaker plants produce twice the carbon emissions and twenty times the NOx emissions per unit of energy generated as compared to a typical thermal plant[25].

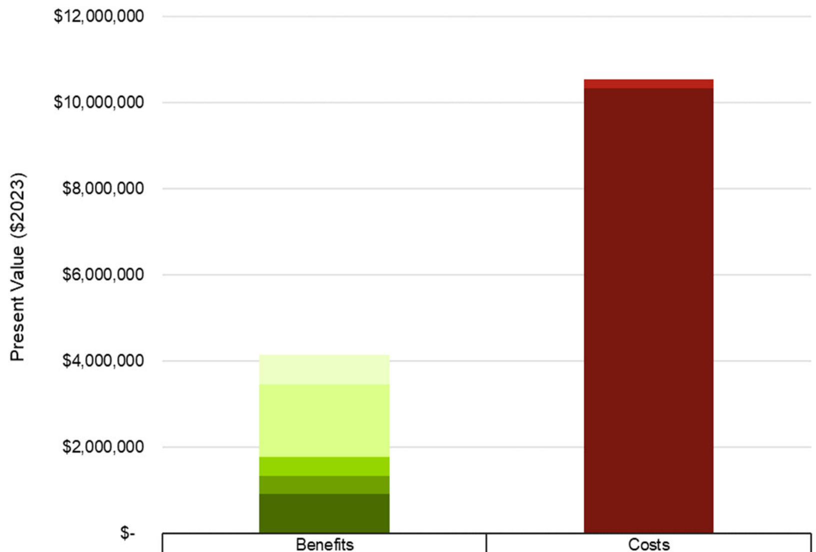
Some fossil fuel peaker plants may be located in disadvantaged communities causing air pollution to predominantly lower income residents in the area. Therefore, lowering peak demand through use of residential battery storage paired with solar will help provide cleaner air to low-income residents in a disadvantaged community.

Even though the benefit-to-cost ratios for the Residential Energy Storage System Incentive Program are below 1.0 (SCT = 0.38, UCT = 0.68, RIM = 0.65), PSEG Long Island believes that energy storage can be cost-effective for its customers and society. As costs fall and energy storage becomes more economically attractive over time, PSEG Long Island can use lessons from this program to help accelerate the market.

One important parameter that impacts the UCT for the program is the incentive level. PSEG Long Island estimates that reducing the per kWh incentive to $125-$150/kWh (from $200/kWh) will result in a UCT benefit-to-cost ratio close to or over 1.0. While PSEG Long Island is currently proposing the incentive level at $200/kWh, PSEG Long Island is open to considering a lower level of incentive for the new block of storage incentives. As the program progresses, PSEG Long Island intends to track costs of the storage systems participating in the program on an ongoing basis and evaluate whether incentive levels should be adjusted.

[24] The New York ISO & Grid Reliability, February 2021 report
[25] Energy Storage Roadmap, 2018

Figure 5-1. Residential Energy Storage System Incentive Program Present Value Benefits and Costs of SCT



	Benefits	Costs
Net Non-Energy Benefits	$688,446	$-
Avoided Outage Costs	$1,663,856	$-
Avoided Energy (LBMP)	$14,634	$-
Avoided Generation Capacity Cost (AGCC)	$452,610	$-
Avoided Transmission Capacity Infrastructure	$406,640	$-
Avoided Distribution Capacity Infrastructure	$919,858	$-
Program Administration Costs	$-	$197,600
Participant DER Cost	$-	$10,345,371
Total	$4,146,045	$10,542,971

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Avoided Distribution Capacity Infrastructure**	Based upon marginal capacity costs and estimated peak demand reduction	0.92	
2	**Avoided Transmission Capacity Infrastructure**	Based upon marginal capacity costs and estimated peak demand reduction	0.41	
3	**Avoided Generation Capacity Cost (AGCC)**	Based upon marginal capacity costs and estimated peak demand reduction	0.45	
4	**Avoided Outage Costs**	Calculated by valuating the avoided cost of acquiring a home backup generator	1.66	
5	**Net Non-Energy Benefits**	Includes Investment Tax Credit (ITC) applied to upfront storage system costs (22% for 2023)	0.69	
6	**Avoided Energy (LBMP)**	Based upon 5% and 10% of systems enrolled in TOU rates in 2023 and 2024, respectively	0.01	
7	**Participant DER Cost**	Accounts for participant cost of energy storage system hardware and installation cost		10.35
8	**Program Administration Costs**	Includes costs for customer outreach and marketing		0.20
	Total Benefits		**4.15**	
	Total Costs			**10.54**
	SCT Ratio		**0.39**	

NPV = Net present value

Performance Measurement and Reporting

To calculate the realized benefits and costs of the Residential Energy Storage System Incentive Program, PSEG Long Island will track the following metrics:

- **Number of Systems Enrolled –** Measure the level of participation in the incentive program, broken out by LMI and non-LMI. PSEG Long Island will use this information to determine whether increased incentives for LMI communities are effective in increasing participation for ESS.
- **ESS Costs –** Collect data on the total hardware and installation costs of energy storage systems enrolled in the program. This data will be used to verify the projected cost estimates or adjust incentive levels.
- **Utility Funds Committed –** Track the funds committed to assess the total program costs.

5.2 BTM Storage with Solar Program

2022 Status	Operational
2023 Status	Operational
Start Year	2019
Funding Approved Through	2022
Description and Justification	The BTM Storage with Solar program offers the opportunity for third-party aggregators to install batteries paired with new or existing solar for residential PSEG Long Island customers. The costs associated with aggregation and enrollment outweigh the compensation customers would receive through the DLM tariff. The initiative was completed in 2021 and is now operational.

The BTM Storage with Solar Program offers the opportunity for third-party aggregators to install batteries paired with new or existing solar for residential PSEG Long Island customers. The program utilized a tariff-based incentive through which third-party aggregators and participants were compensated for verifiable load reductions. It was designed to alleviate overloading in target areas, increase customer engagement and energy literacy, and support state storage goals. The program was implemented in 2019 and was ongoing through end of 2021.

5.2.1 Implementation Update

In 2021, PSEG Long Island continued to experience lower-than-expected enrollment in the DLM tariff due to the COVID-19 pandemic. By end of 2021, 865 battery storage customers had applied for the NYSERDA NY Sun Storage Incentive Program, and 764 projects have been completed and issued rebate payments, of which there were 17 participants enrolled in the DLM tariff.

Success Snapshot

This initiative was completed in 2021 and as a result, 865 battery storage customers applied for the NYSERDA Sun Storage Incentive Program, and 764 projects were completed and issued rebate payments.

While only 17 systems participated in the DLM tariff in 2021, the number of customer applications for solar PV paired with battery storage exceeded PSEG Long Island's expectations. The high rate of adoption is likely due to the incentives offered by NYSERDA, which have resulted in increasing rates of developer interest in and adoption of storage. The success of the NYSERDA program indicates the incentives and rebate model is attractive to customers and developers for battery storage installations; however, unless such storage is discharged on peak days, the Utility does not realize any benefits.

Scope Update

The scope of the BTM Storage program and the DLM tariff program was completed in 2021. Beyond the scope of this project, PSEG Long Island is exploring expanding this program by incorporating learnings and addressing challenges experienced in the implementation of this project (see Residential Energy Storage System Incentive in Section 5.1).

Schedule Update

BTM Storage with Solar program was completed in 2021 and is now operational.

5.2.2 Funding Reconciliation

The budget remains as previously reported in the 2021 Utility 2.0 Plan. The overall actual spend tracked closely to the budgeted amount of $0.16 million, which only included budget through 2020.

5.2.3 Performance Reporting

See the two subsections below for information regarding the lessons learned and next steps for the BTM Storage with Solar program.

Lessons Learned

Through the duration of the program, PSEG Long Island learned about numerous challenges that aggregators face when enrolling their systems in the DLM tariff. The costs associated with aggregation and enrollment outweighed the compensation they would receive through the tariff. Under current participation levels, aggregators do not have sufficient capacity to warrant participation.

Next Steps

PSEG Long Island is working to overcome these challenges by working closely with aggregators and OEMs and will implement lessons learned through this program as part of the proposal for the new Residential Storage Program (Section 5.1).

5.3 Connected Buildings Pilot

2022 Status	Active
2023 Status	Active
Start Year	2022
Funding Approved Through	2025
Description and Justification	The Connected Buildings Pilot will demonstrate how insights into and control of consumption help provide customers with bill savings, add grid value through reduced supply and infrastructure costs, and support beneficial electrification. This initiative is expected to launch in 2022 and run through 2023.

This technology pilot demonstrates the benefits of integrated controls that enable customer insight into and control of consumption which can lead to more efficient and optimal energy management, providing customers with bill savings, adding grid value through reduced supply and infrastructure costs, and supporting beneficial electrification.

The pilot tests a smart electric panel to integrate and control end-use devices. The pilot will be conducted with PSEG Long Island residential customers (the device is only designed for residential homes), beginning with single-family homes seeking to add significant new DERs such as solar, storage, electric vehicle supply equipment (EVSE), and heat pumps. The smart panel enables breaker-level monitoring, better insight into customer loads, and more granular control of certain DER (e.g., storage).

5.3.1 Implementation Update

The Connected Buildings Pilot is currently in the contracting stage for the smart electric panels and the installation of the panels. The pilot will launch to customers in the second half of 2022 and run through 2023.

Scope Update

PSEG Long Island initially proposed targeting 150 residential single-family homeowners for the pilot. However, in response to Staff recommendations to the 2021 Utility 2.0 Plan, PSEG Long Island will instead target 75 customers. While PSEG Long Island will offer and encourage these participants to enroll in the TOU rates and other applicable offerings, participants will not be required to commit to enrolling in any of the offerings as a condition of participating in the Project.

Schedule Update

The schedule remains as previously proposed in the 2021 Utility 2.0 Plan. The pilot will launch to customers in the second half of 2022 and run through 2023.

Risks and Mitigations

Table 5-6 identifies potential risks and mitigations for the Connected Buildings Pilot.

Table 5-6. Connected Buildings Risk and Mitigation Assessment

Category	Risk	Mitigation
Technical	Vendor technology may not support all desired DER or event types.	Coordinate with vendor to ensure detailed pilot design is compatible with technology capabilities.

5.3.2 Funding Reconciliation

No net changes to the overall budget are expected for this initiative, aside from shifting a portion of the budget associated with customer outreach and evaluation from 2022 to 2023.

Table 5-7. Connected Buildings Pilot Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Request 2023	Projected (Not Requested) 2024	Projected (Not Requested) 2025	Total
Capital	-	-	-	-	-	-	-	**-**
O&M	-	-	-	0.57	0.08	-	-	**0.65**
Total	**-**	**-**	**-**	**0.57**	**0.08**	**-**	**-**	**0.65**

Table 5-8. Connected Buildings Pilot Capital and Operating Expense Variance

	2021	2022	2023	2024	2025
Capital	-	-	-	-	-
O&M	-	0.08	(0.08)	-	-
Total	**-**	**0.08**	**(0.08)**	**-**	**-**

5.3.3 Performance Reporting

Once implemented, the Connected Buildings Pilot is expected to:

- Enable device monitoring and control, and allows additional electric loads and DER to be easily integrated
- Help achieve New York State climate and energy goals
- Better inform related projects proposed in the Utility 2.0 Plan and other innovative beneficial electrification projects

5.4 DER Visibility Platform

2022 Status	Active
2023 Status	Active
Start Year	2021
Funding Approved Through	2025
Description and Justification	The DER Visibility Platform enables PSEG Long Island's distribution operators to better manage DER under various system conditions. Development of the platform began in mid-May 2022 and is expected to continue as scheduled with the platform going live in late 2023.

The DER Visibility Platform is an operational platform that enables PSEG Long Island's distribution operators to monitor and manage DER under different system conditions.

The platform supports the increase of DER penetration and interconnection to the PSEG Long Island distribution system by providing visibility to operators so that operational decisions can be made under different system conditions considering the impact of DER connected onto the circuit. The platform is envisioned to provide additional capabilities such as visualizing the output and status of the DER, displaying custom aggregated Supervisory Control and Data Acquisition (SCADA) data, and accommodating any other controls and data that are available through SCADA.

Once it is fully implemented and the data from all existing sites is migrated, PSEG Long Island will continue to connect new DER locations with SCADA data to the new platform. The finalization of requirements and project kickoff are expected to begin in 2022.

5.4.1 Implementation Update

See the scope and schedule updates below for the DER Visibility Platform.

Scope Update

Additional scope has been added for the product vendor's engineering consulting services to support re-engineering of the GIS interface for DER, integration of a 3rd party weather interface and PSEG Long Island performance test cases. Additionally, the third-party system integrator will provide project management and subject matter expert services that were not previously identified.

Schedule Update

As reported in the previous filing, the project kick-off had been delayed from its original 2021 start date to 2022 due to constraints with IT resources and delays with the product vendor. The kickoff for the project was in mid-May and the project is expected to continue as scheduled thereafter with the platform going live in late 2023. "Go live" here means that the DER are fully integrated into the existing DSCADA platform to display feeder connectivity as well as SCADA data. All existing DER over 1 MW with available SCADA data and considered "distribution-type DER" will be integrated (a minimum of 27 DER).

Risks and Mitigations

The potential risks and proposed mitigation steps for developing the DER Visibility Platform are outlined in Table 5-9.

Table 5-9. DER Visibility Platform Risk and Mitigation Assessment

Category	Risk	Mitigation
Timeline	Delays in project timeline due to IT integration delays	Incorporate contingencies in project schedule by considering timeline buggers
Budget	Uncertain budget because the cost of the software platform depends on the selected third-party vendor	Incorporate 50% risk and contingency in project budget
Stakeholder Engagement	Delays in project timeline due to constraints on IT staff	Ensure availability of IT team to support installation of the platform

5.4.2 Funding Reconciliation

The initiative's capital budget includes IT system integration costs, such as product vendor software design and configuration, engineering and implementation services, cybersecurity network architecture reviews and testing, interface design and integration services, user and system testing, and product licenses. Ongoing O&M expenditure will be required to cover annual IT maintenance of the platform.

The additional funding requested for the system integrator to provide project management and subject matter expertise support is the largest source of variance from the previously forecasted budget. Another source of additional funding request is for the product vendor to support re-engineering the GIS interface for DER. Additionally, the project kickoff delay increased product vendor costs, system integrator costs, and increased ongoing O&M costs due to cost escalations. Separate contracts with the system integrator and the product vendor have been finalized.

The need for GIS interface re-engineering to support DER Visibility was identified in pre-planning and contract discussions with the product vendor. A GIS interface to import DER data into the Distribution Supervisory Control and Data Acquisition (DSCADA) eMap must be designed and implemented to display the DER in the eMap. The product vendor has proposed a more direct and automated GIS data connection into DSCADA than currently exists to improve the import process.

The system integrator will provide project management and subject matter expertise to ensure the project can be successfully delivered. The system integrator brings product knowledge as well as industry experience in deploying Distributed Energy Resources Management System (DERMS) solutions, which PSEG Long Island does not currently have.

The DER Visibility project budget is reflective of the recommendation by the DPS[26] to utilize the annual Utility 2.0 filing to request the associated capital funding to support the IT Labor, developer-required licenses, and other capital costs for the upcoming year. As such, 2023 capital costs, including the product vendor and system integrator costs described above, were not included in the previously approved budget and now appear as a variance. In addition, the DPS recommendation to reduce the project risk and contingency from 50% to 20% was adopted in the previously approved DER Visibility budget. Ultimately, the additional identified scope and escalated vendor costs discussed in this section led to an increase in required budget, contributing to a budget variance.

Table 5-10. DER Visibility Platform Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Request 2023	Projected (Not Requested) 2024	Projected (Not Requested) 2025	Total
Capital	-	-	-	4.41	3.31	0.17	0.17	**8.06**
O&M	-	-	-	-	0.06	0.07	0.08	**0.20**
Total	**-**	**-**	**-**	**4.41**	**3.37**	**0.24**	**0.25**	**8.26**

Table 5-11. DER Visibility Platform Capital and Operating Expense Variance

	2021	2022	2023	2024	2025
Capital	-	(0.46)	(3.31)	(0.17)	(0.17)
O&M	-	0.07	(0.01)	(0.02)	(0.02)
Total	**-**	**(0.39)**	**(3.32)**	**(0.19)**	**(0.19)**

5.4.3 Performance Reporting

Once implemented, the DER Visibility Platform is expected to:

- Monitor and enable increased DER penetration levels on PSEG Long Island's system
- Help achieve New York State climate and energy goals

[26] 1. DPS Matter 14-01299: Review of and recommendations regarding the Long Island Power Authority and PSEG Long Island's 2020 Utility 2.0 Plan Annual Update and 2020 Energy Efficiency and Demand Response (EEDR) Plan

- Better inform related projects proposed in the Utility 2.0 Plan and other DSP-related projects

5.5 Locational Value Study

2022 Status	Completed/Continuous Improvement
2023 Status	Operational
Start Year	2019
Funding Approved Through	2022
Description and Justification	The Locational Value Study developed a methodology to calculate the deferral value of T&D capital projects. The Locational Value Tool utilizes this methodology which feeds into the NWA Planning Tool to evaluate potential candidates for NWA projects.

The Locational Value Study utilized probabilistic load forecasting methodology combined with contingency analysis to identify T&D constraints. The study also developed a methodology to calculate the deferral value of T&D capital projects. Under this effort, the team also built a locational value tool, which estimates the value that is used to defer T&D capital investment.

The Locational Value Study and its associated tool and report were completed in late 2020. Outputs of the tool are used as an input into the NWA Planning Tool, which has been completed and evaluates potential candidates for NWA projects. The Locational Value Tool evaluates parameters such as the load relief required for circuits under consideration and growth rates to calculate the value of the DER to the project.

5.5.1 Implementation Update

See the scope and schedule updates below for the Locational Value Study.

Scope Update

The scope of the Locational Value Study and Tool are as originally proposed.

Schedule Update

The Locational Value Tool is complete and continues to be maintained.

5.5.2 Funding Reconciliation

Capital Non-Labor spend for third-party support was slightly higher in 2021 than expected due to late payments from the vendor. The 2022 budget is forecasted to remain as previously forecasted, after which time the project will not require Utility 2.0 budget.

Table 5-12. Locational Value Study Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	0.20	0.32	0.01	-	**0.52**
O&M	-	-	0.00	0.03	**0.03**
Total	**0.20**	**0.32**	**0.01**	**0.03**	**0.55**

Table 5-13. Locational Value Study Capital and Operating Expense Variance

	2021	2022
Capital	(0.01)	-
O&M	0.03	-
Total	**0.02**	**-**

5.5.3 Performance Reporting

Although the Locational Value Study does not have any projected direct KPIs or benefits, the study and tool is being used as an input to evaluate NWA projects that aim to defer the need for capital investments.

Lessons Learned & Next Steps

The Locational Value Tool, developed from the findings of the Locational Value Study, will continue to be maintained and utilized as a tool for PSEG Long Island to evaluate NWA projects that aim to defer the need for capital investments.

5.6 Non-Wires Alternatives Planning Tool

2022 Status	Active
2023 Status	Operational
Start Year	2020
Funding Approved Through	2022
Description and Justification	The NWA Planning Tool offers PSEG Long Island the ability to assess the feasibility of an NWA as an alternative to planned capital construction. In 2020, a vendor was selected, and PSEG Long Island worked with the Data Analytics and T&D organizations to develop the tool. The Tool was expected to be complete in 2021 but is delayed to mid-2022 due to data language conversion from STATA to Python.

The NWA Planning Tool offers PSEG Long Island the ability to assess the feasibility of an NWA as an alternative to a planned capital construction project by computing achievable customer penetration percentages of different customer-sited capacity reduction measures based on known customer data for that circuit and price elasticity for the customer percentage of the measure(s) cost.

The tool incorporates data from the Data Lake, leverages outputs from the Locational Value Study (see Section 5.5) and other customer inputs (usage data, prior program participation) to forecast whether a solution set could be achievable by a third-party contractor that would meet the load requirements necessary to defer a planned capital construction project. If PSEG Long Island finds a feasible solution, it will solicit for an RFP or Request for Information (RFI) and will review technical proposals submitted to determine if it could reliably defer the planned capital construction project while being cost effective. If a solution was found not to be feasible through either the NWA Screening Tool or RFP/RFI submission, PSEG Long Island would recommend the capital construction project proceed to resolve the load constraint. If a solution was to be found feasible, and economic, compared to the capital construction project, a bidder would be selected, awarded the bid, and would target customers to take on measures by the specified need dates as part of the energy services agreement (See Section 5.7 for details on NWA Process Development).

5.6.1 Implementation Update

A vendor was selected in the first quarter of 2020 and worked with the Data Analytics and T&D organizations to develop the tool throughout 2020. The NWA Planning Tool and relevant instructions and documentation were completed in 2021. PSEG Long Island is currently working with the third-party vendor to convert the data language from STATA to Python. This will allow PSEG Long Island to update relevant data (on their own) that the tool can utilize so that the results are relevant to the area(s) being assessed.

Scope Update

The scope remains as previously reported in the 2021 Utility 2.0 Plan.

Schedule Update

The initial NWA Planning Tool scope was completed in 2021. Additional scope providing for modeling data assumptions (STATA to Python) is expected to be completed by Q3 2022. Unless there are other enhancements requested, this should be the completion of the project scope.

5.6.2 Funding Reconciliation

No net changes to the overall budget are expected, but some costs are shifting from 2021 to 2022 due to delays in schedule.

Table 5-14. NWA Planning Tool Capital and Operating Expense Budget and Forecast

	Actual 2019	Actual 2020	Actual 2021	Updated Forecast 2022	Total
Capital	-	-	-	-	**-**
O&M	-	0.08	0.09	0.03	**0.19**
Total	**-**	**0.08**	**0.09**	**0.03**	**0.19**

Table 5-15. NWA Planning Tool Capital and Operating Expense Variance

	2021	2022
Capital	-	-
O&M	0.03	(0.03)
Total	**0.03**	**(0.03)**

5.6.3 Performance Reporting

There are no direct projects KPIs or benefits for the NWA Planning Tool, but indirect benefits of the tool will include improved insights for DER, BTM customer solutions, and grid investments.

5.7 NWA Process Development

2022 Status	Active
2023 Status	Complete
Start Year	2021
Funding Approved Through	2021
Description and Justification	PSEG Long Island is developing a formalized, replicable, and transparent process for identifying, selecting, procuring, and deploying NWA for T&D-level deferral opportunities. Due to schedule delays, the cost of $0.5M will be incurred in 2022 rather than in 2021, but the total project cost remains as previously reported.

PSEG Long Island is developing a formalized, replicable, and transparent process for identifying, selecting, procuring, and deploying Non-Wire Alternatives (NWA) for transmission and distribution-level deferral opportunities. This process includes defining market solicitation principles, developing a bidders list and templates for solicitation, bid screening, contracting, and developing a funding mechanism that enables PSEG Long Island to properly charge NWA solution costs without lengthy budget re-appropriation efforts or postponement to future budget cycles.

5.7.1 Implementation Update

PSEG Long Island is currently working with a third-party consultant to develop an NWA Process Playbook that will include detailed guidelines around the following components:

- NWA opportunity identification
- Market solicitation process
- Accounting process
- NWA relevant Contract Terms

PSEG Long Island expects to use the NWA Process Playbook for all future NWA opportunities.

5.7.2 Funding Reconciliation

Due to schedule delays, the cost of $0.50M will be incurred in 2022 rather than in 2021. The total project cost remains as previously reported.

Table 5-16. NWA Process Development Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	-	-	-	-	**-**
O&M	-	-	-	0.50	**0.50**
Total	**-**	**-**	**-**	**0.50**	**0.50**

Table 5-17. NWA Process Development Capital and Operating Expense Variance

	2021	2022
Capital	-	-
O&M	0.50	(0.50)

Total	**0.50**	**(0.50)**

5.7.3 Performance Reporting

NWA Process Development does not have specific KPIs or benefits. The goals of this work remain the same as originally proposed and are expected to ensure the following for PSEG Long Island's NWA solution implementation:

- Avoid delays in budgeting and approval that may lead to missed NWA opportunities
- Avoid issues associated with limitations in O&M budget that lead to de-prioritization of NWA opportunities
- Procure the most cost-effective solutions to address NWA opportunities
- Improve the alignment of NWA planning and procurement with other New York utilities

5.8 Rate Modernization – Time of Use

2022 Status	Active
2023 Status	Operational
Start Year	2019
Funding Approved Through	2023
Description and Justification	AMI deployment enabled PSEG Long Island to offer a wider variety of pricing plans and energy management tools helping customers take advantage of the new AMI-enabled capabilities. PSEG Long Island implemented the Advanced Billing Engine enhancing its legacy billing systems to introduce variable pricing options. Four new residential and one small commercial Time-of-use (TOU) rate options were introduced in 2021 and in 2022 while a new large commercial TOU rate has been designed and is planned for launch in January of 2023.

PSEG Long Island introduced its Rate Modernization initiative in the 2018 Utility 2.0 Plan. Rate Modernization aims to offer customers rate options that enable energy cost savings, are simple to understand, easy to compare, and that meet the Utility's and the customers' current and future needs. AMI deployment enables the functionality required to modernize PSEG Long Island's rates and provide customers with a wider variety pricing plan (rate) options as well as tools to better control electricity usage and make cost-effective choices with increased convenience.

To provide new interval pricing options to customers, PSEG Long Island has implemented an Advanced Billing Engine enhancing the Utility's legacy billing systems and applications. Five new TOU rate options were introduced to customers in February of 2021: three residential 3-block plans (rates 190, 191, and 192), one residential overnight 2-block plan (rate 193), and one small business 3-block plan (rate 292). In 2022, one new large commercial TOU rate has been designed (rate 294) and is planned for launch in January of 2023. Consistent with the Rate Modernization initiative, the TOU options are proposed as voluntary opt-in pricing programs, in order to enhance customer satisfaction while encouraging customers to develop new habits and routines. PSEG Long Island, in collaboration with LIPA, presented four new residential heat rate options (Rate 580 options) which DPS did not recommend moving forward with at this time.

In support of the new TOU rates rollout, PSEG Long Island developed a marketing campaign and a direct-to-customer communications strategy to raise customer awareness and help them take advantage of the variable pricing based on time-of-day electricity usage. PSEG Long Island leveraged multiple channels including emails, direct mail, public website and a MyAccount personalized rate comparison and selection feature along with a newly designed bill for customers enrolled in a TOU rate.

PSEG Long Island completed a revised BCA as part of the DPS inquiries associated with the submission of the 2021 U2.0 Filing. Under the updated BCA, Rate Modernization returns an SCT benefit to cost ratio of 2.65, a UCT benefit to cost ratio of 2.61 and a RIM benefit to cost ratio of 1.74.

In 2022 PSEG Long Island will be accelerating Year 1 of the Marketing Pilot, targeting 12,000 customer adoptions, a doubling of the original enrollment goal. In addition, the systems and processes will be updated to offer a new rate option for large commercial customers in January 2023. This will include enhancements to the Advanced Billing Engine, MyAccount self-service rate comparison tool, legacy billing systems, bill designs, and internal training required to support the new rates and associated customer service.

5.8.1 Implementation Update

See the scope and schedule updates below for Rate Modernization.

Scope Update

The scope of Rate Modernization remains as originally proposed in the 2018 Utility 2.0 Plan.

In 2021, PSEG Long Island took actions and implemented technology necessary to enable and encourage customer enrollment in TOU rates:

- Customer research informed the development of the behavioral campaign, search engine optimization (SEO), website development and content, video, emails, and direct mail
- Website development enabling more sophisticated search engine optimization content launched in November
- A production phase pilot allowed the team to test the systems with employees, friends and family and other interested early adopters leading to process improvements prior to marketing campaigns to increase mass market adoption
- Development of a communications plan finalized strategy, tactics, themes, and key messages
- MyAccount updates addressed the need for new information for TOU-enrolled customers and saw the introduction of a rate comparison tool for customers to assess their own best rate option
- Revised and refined rate brochures for 2022 residential and commercial customers
- Produced TOU promotional videos
- Finalized initial creative content for emails and direct mail campaigns, and initiated a targeted campaign shortly after the launch of the self-serve rate comparison tool

PSEG Long Island additionally built the back-end systems needed to support adoption of TOU rates among residential and commercial customers in 2021.

- CSRs in the call center have been trained to support new TOU rates enrollments
- Awareness trainings were developed and delivered to impacted business units as part of the overall change management support
- A rate conversion process review was established to formalize the development of new TOU rates to better serve customers into the future

- Marketing data has been refined and continuous improvement processes put in place
- Established a baseline with the 3rd party energy measurement and verification vendor to evaluate pilot's achieved energy conservation

Major customer facing elements of Rate Modernization:

Customer Facing Elements

An email campaign, website, bill redesign, and MyAccount rate comparison tool were developed to encourage enrollment as well as educate and engage customers.

Email Campaign: The Marketing plan includes a series of personalized promotional emails to drive customer adoption. Once enrolled, customers would transition into the educational nurture campaign that introduces key information and next steps for what the customer can expect on their new rate. Prior to active promotion of the new rates to customers, PSEG Long Island conducted a production test phase and gathered feedback through employee enrollment followed by a "friends and family" promotion of the rate options and launch of the self-serve MyAccount Rate Comparison tool. Employees and friends and family provided insights into their experiences. PSEG Long Island incorporated that feedback improving the systems, websites, marketing materials and other customer channel experiences. Starting in December of 2021, PSEG Long Island launched the first block of proactive outbound emails, targeting customer segments with a higher likelihood of benefit by enrolling in one of the TOU rates. The team analyzed seasonality and usage profiles in conjunction with the unique aspects of each rate to determine the best fit rate for customers. PSEG Long Island has seen stepped increase in customer interest since launching the targeted marketing campaign in December.

Website: Significant educational content was deployed on the PSEG Long Island public website (6.) including core information about the What's and Why's of TOU in addition to How to Switch. Rate plan details, a promotional video, FAQ's, use case articles, and customer testimonials can all be found on the Search Engine Optimized (SEO) website.

MyAccount Rate Comparison Tool: The PSEG Long Island team created an online rate comparison and selection tool. The tool is available to customers through MyAccount and provides a comparison of a customer's current rate to available rate options. It provides an estimated annual cost based on current rates and the historic 365-day AMI metered usage along with listing plan details and specifics about the peak and off-peak timing within call-to-action buttons to select a plan and enroll.

Bill Redesign: The new TOU bills incorporate best practices learned from visits and discussions with other utilities, customer research, user testing and feedback from the friends and family pilot launch to create a best-in-class bill format with insightful visually engaging new graphs and charts. Customers enrolled in any of the new TOU rate options received these bills that highlight usage and associated costs in each of the TOU time block periods.

Marketing support in 2022 is designed to target customers with potential for significant bill savings who have been identified through data analysis. With enrollment underway, further data collection and analysis has begun to assess the efficacy and continuous improvement needs of the public website, MyAccount, email and direct mail. Enhancements to the website provide customers with additional content and an optimized enrollment funnel structure. A customer-facing PDF guide to choosing TOU has been developed as a resource to further empower and educate customers on enrolling in the new rates.

One large customer TOU rate has been tentatively approved by LIPA and the DPS and is on track to be deployed in Q1 2023. Four residential space heating rates were in development jointly with LIPA, however, DPS did not recommend moving forward with them at this time.

Schedule Update

In 2021, PSEG Long Island completed the production pilot phase of Rate Modernization. 2022 marks the beginning of the customer marketing pilot in which PSEG Long Island begins targeted marketing campaigns. The enrollment goal has been doubled for 2022 to increase customer adoption.

Rate Modernization continues to add new TOU rates that align to LIPA's and DPS's vision, including a large commercial rate for Q1 2023. PSEG Long Island has implemented a continuous improvement culture within the Rate Modernization team that will build upon current progress to introduce new rates informed by customer and market research.

5.8.2 Funding Reconciliation

The Rate Modernization budget is expected to come under budget in 2022 by as detailed in Table 5-18.

Table 5-18. Rate Modernization Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	1.59	3.92	2.68	2.00	**10.19**
O&M	0.57	0.51	1.33	4.03	**6.44**
Total	**2.16**	**4.43**	**4.01**	**6.03**	**16.63**

Table 5-19. Rate Modernization Capital and Operating Expense Variance

	2021	2022
Capital	(0.49)	0.19
O&M	2.96	0.94
Total	**2.47**	**1.13**

5.8.3 Performance Reporting

Performance metrics for Rate Modernization are driven by customer adoption rates. Due to the delays in project execution, planned customer enrollment levels were not achieved in 2021. As enrollment increases in 2022, performance metrics will be solidified, and data collected will be reported out in the 2023 filing.

Lessons Learned

PSEG Long Island has taken note of specific challenges that implementing Rate Modernization has illuminated. Most notably, the importance of research, resistance to change from customers and the value of the production phase pilot have stood out throughout the Rate Modernization implementation process.

Next Steps

Rate Modernization is expected to scale with offering TOU rates to all eligible PSEG Long Island customers through an opt-in model through December 2023. Marketing tests are ongoing and customer segmentation is continuing to provide guidance on how to target different customer personas. LIPA is moving forward with a recommendation to change nearly all customers' rates to TOU rates, starting the opt-out (default rate) conversion in January of 2024. This will necessitate significant expenditures in 2023 to address numerous backend system updates, customer facing technologies, billing, as well as personalized communication to educate customers about their rate options and develop additional tools and functionality to help customers adopt to a time-of-use rate design.

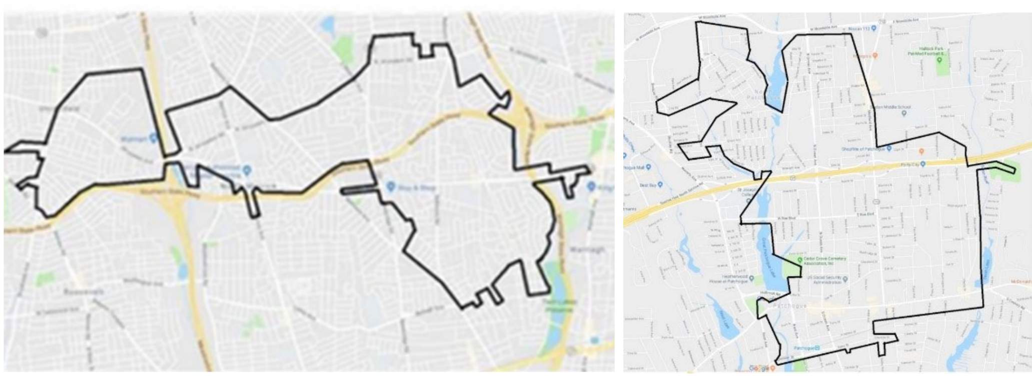
The details regarding the TOU opt out rate design are currently being developed and evaluated by LIPA, as well as the roll out plan. Once the final rate designs, alternative opt out rate options, customer segment impact analyses, and deployment plans are developed, then detailed tactical IT business requirements, business process design, staffing, training and change management, as well as customer education and engagement plans will be developed. Additional budget requests as part of the LIPA's annual budgeting and emerging project requirement will be needed to support this transition.

5.9 Super Savers

2022 Status	Active
2023 Status	Patchogue = Active and North Bellmore = Complete
Start Year	2019
Funding Approved Through	2023
Description and Justification	Super Savers is an NWA seeking to reduce peak by 4 MW to defer traditional capital investment. Through the initial pilot in North Bellmore, PSEG Long Island is learning how to encourage the community adoption of EE and DER measures and whether they can shed enough load to defer infrastructure upgrades. The Super Savers program in North Bellmore was extended to 2022 and expanded to Patchogue, which will run through 2023.

Super Savers is an NWA seeking to reduce peak demand to defer traditional capital investment. Through this pilot, PSEG Long Island is learning how to encourage community adoption of EE and DER measures and whether they can shed enough load to defer infrastructure upgrades. The Super Savers program is active on the North Bellmore (4 MW reduction) and Patchogue (2 MW reduction) circuits. Figure 5-2 illustrates the testing areas.

Figure 5-2. North Bellmore (Left) and Patchogue (Right) Super Savers Areas



5.9.1 Implementation Update

By the end of 2021, the North Bellmore Super Savers Program achieved a 2 MW peak demand reduction, representing 50% of the 4 MW peak reduction goal. The Patchogue Super Savers Program launched in early 2021 and has so far achieved 0.7 MW in peak demand reduction, representing 37% of its 2 MW goal. Increased marketing efforts in both N. Bellmore and Patchogue through emails, mailings, door to door and telecommunications have helped to achieve demand reduction by both residential and commercial customers through commercial lighting upgrades and demand response measures.

Success Snapshot

North Bellmore achieved 50% of its total 4 MW peak reduction goal in 2021 and Patchogue has so far achieved 37% of its 2 MW goal.

Scope Update

The scope remains as previously reported in the 2021 Utility 2.0 Plan.

Schedule Update

The schedule for both the North Bellmore and Patchogue Super Savers Program remains as previously reported in the 2021 Utility 2.0 Plan. North Bellmore will conclude in 2022.

Risks and Mitigations

The potential risks and proposed mitigation steps for the Patchogue Super Savers Program are outlined in Table 5-20.

Table 5-20. Super Savers Program (Patchogue) Risk and Mitigation Assessment

Category	Risk	Mitigation
Customer Engagement	Low rate of participation, even with nearly or completely free measures could impact program benefits	Build more targeted marketing strategies and higher incentives to build customer engagement

5.9.2 Funding Reconciliation

The actual spending for the Super Savers Program in 2021 was slightly less than the approved budget, largely due to the impacts of the pandemic on marketing and installation efforts. As a result, the unused budget from 2021 will be redirected specifically to Patchogue efforts for 2023. The overall budget for Super Savers remains as approved in the 2021 Utility 2.0 Plan.

Table 5-21. Super Savers Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	Request	Projected (Not Requested)	Projected (Not Requested)	
	2019	2020	2021	2022	2023	2024	2025	Total
Capital	-	-	-	-	-	-	-	**-**
O&M	0.48	0.29	0.87	1.02	0.79	-	-	**3.46**
Total	**0.48**	**0.29**	**0.87**	**1.02**	**0.79**	**-**	**-**	**3.46**

Table 5-22. Super Savers Capital and Operating Expense Variance

	2021	2022	2023	2024	2025

Capital	-	-	-	-	-
O&M	0.32	-	(0.33)	-	-
Total	**0.32**	**-**	**(0.33)**	**-**	**-**

5.9.3 Performance Reporting

The North Bellmore Super Savers Program achieved 50% of its peak demand reduction target of 4 MW through 2021. The realized savings fell below the targets largely due to the impacts of the pandemic on marketing and installations.

The Super Savers Program previously relied heavily on door-to-door marketing to target specific customers, but this marketing strategy was difficult to implement over the last couple of years.

Although the peak demand reduction targets have not been met, all incremental reduction helps in assessing whether capital expenditure deferral is possible. The demand reduction and the insights gained from this program ultimately save or postpone investments that otherwise may have occurred.

In late 2021, PSEG Long Island conducted an independent evaluation of the savings achieved at the North Bellmore circuit through Super Savers. Table 5-23. shows the difference between deemed savings (as previously reported in the 2021 Utility 2.0 Plan) and evaluated savings (conducted in 2021). The evaluated savings are lower than the deemed savings primarily due to the difference in quantification methodology (e.g., bottom-up).

Table 5-23. Super Savers North Bellmore Benefit Reporting ($M)

Benefit	Target Through 2021	Realized Through 2021 (Deemed)	Realized % (Deemed)	Realized Through 2021 (Evaluated)	Realized % (Evaluated)
Avoided F&PP Costs	1.07	0.54	50%	0.35	33%
Avoided Capital Costs (Non-Labor)	1.46	1.38	95%	0.57	39%
Avoided Carbon Emissions	0.27	0.22	79%	NA	NA

Due to the delay in the launch of the Patchogue Super Savers Program, no benefits are reported for 2021.

6. Customer Insights and Analytics

PSEG Long Island is committed to providing customers with greater access to data and information, enabling them to better manage their energy use. As detailed in Section 1.1, PSEG Long Island evolved its Utility 2.0 vision and framework to align with statewide priorities. *Customer Insights and Analytics* was a priority added by PSEG Long Island due to the significance of AMI deployment and the benefits and capabilities it enabled across the program and towards achieving the Utility 2.0 vision.

The development and deployment of AMI technology and systems is foundational to integrating clean energy options for customers. PSEG Long Island completed 95% of the planned AMI deployment by September 2021, approximately 15 months ahead of the original deployment plan. By utilizing individual and aggregate time interval usage insights and other data provided by the AMI system, PSEG Long Island implemented customer-facing and internal capabilities such as Data Analytics and Next Generation Insights to empower customers to take control of their energy usage more effectively and support efficient management of the electric grid.

The proposed Integrated Energy Data Resource (IEDR) platform will have the necessary information for DER providers to identify areas with high locational value for future interconnection planning through the availability of hosting capacity, solar siting, and aggregated customer usage data in a common platform. Promoting access to this data will support increased penetration of DERs and contribute to several New York State priorities.[27]

The Commercial and Industrial (C&I) Demand Alert Pilot intends to help customers avoid or better manage demand-driven costs through proactive alerts and recommended actions. This pilot hypothesizes that this capability will help businesses avoid exceeding rate demand threshold over two consecutive billing periods, thereby helping them stay on the cheaper rate. This could also make electrical demand more predictable and potentially reduce peak energy demand on the grid. Combining the C&I demand alert capability with established EE programs and customer education and outreach will support and bolster the state and PSEG Long Island's beneficial electrification goals.

This chapter is organized into seven subsections that provide an update for Utility 2.0 initiatives that directly align with the *Customer Insights and Analytics* priority area. PSEG Long Island notes that the initiatives in this chapter are not limited to only supporting this priority area and likely contribute to others.

Chapter Contents

[27] The Data Access Framework adopted in this Order will serve as a single source for data access policies and provide uniform and consistent guidance on what is needed for access to, and the availability of, energy-related data. Moreover, the Framework will promote data access, while preserving all the necessary protections, to facilitate New York State's policy goals, Case 20-M-0082.

Note that the following two Customer Insights and Analytics projects approved in previous Utility 2.0 Plans have been canceled and closed out of the program. Justification is provided below.

Energy Concierge Pilot

Modeled on its in-person Business Customer Advisor program, PSEG Long Island proposed Energy Concierge as a residential advisory service to increase customer engagement and adoption of PSEG Long Island offerings ultimately improving customer satisfaction. It was envisioned that in-person consultations with customers would improve customer adoption of a wide variety of products and services that PSEG Long Island offers, such as online account (MyAccount) with all the AMI-enabled, customer-facing data and tools, accessing energy insights capability and rate comparison tool, or connecting them to PSEG Long Island's EE trade allies and other third-party energy services providers.

Due to the COVID-19 pandemic, PSEG Long Island decided to adapt the approach converting in-person appointments to remote channels (virtual and phone). Energy Concierge was launched in the fall of 2020 conducting over 50 remote customer appointments over a span of 6 weeks. PSEG Long Island developed a training program, trained contractors, and developed program marketing and outreach materials to support the program.

Based on the remote appointments' limitations, PSEG Long Island concluded that the intended impacts fell short of the expectations and could not match in-person experience, the premise of the pilot. With the COVID-19 pandemic in full swing, PSEG Long Island decided to put Energy Concierge on hold. The project remained on hold throughout 2021 and into 2022 due to evolving CDC guidance and fluctuating COVID-19 risk levels. With almost two years of time elapsing and changing customer expectations and behaviors as a result of COVID and other external factors PSEG Long Island is of the opinion that the project plan, methods, outcomes, and costs need to be revisited. Therefore, PSEG Long Island will revisit this program in 2023 and may submit a revised plan, which would include an outreach and marketing plan, in next year's filing.

Enhanced Marketplace

The legacy marketplace offered to PSEG Long Island customers has been significantly improved and now offers the sale of EV charging equipment, along with a wide variety of energy efficient products such as LED lighting and smart thermostats. The marketplace has also been successful in providing customers with access to EV smart charging equipment.

The previously proposed Enhanced Marketplace was to include five key components:

1. Direct Product Purchase Online Catalog
2. Home Services Marketplace
3. Point-of-Sale Instant Rebates
4. Product Advisor
5. Program Enrollment Center

The 2021 filing indicated that the start of the Enhanced Marketplace development will be delayed to 2023 due to internal resource constraints. However, during that year, the PSEG Long Island team met with vendors to capture platform costs and spoke to other utilities about the engagement rates with their enhanced marketplaces. These utility benchmarking conversations surfaced that the engagement rates for costly enhancements were not significantly higher than engagement rates that PSEG Long Island is already achieving with their marketplace. Therefore, PSEG Long Island deems that the cost, which would consist of an initial outlay and ongoing annual software costs, to continue to invest in the marketplace to enable the listed enhancements is not justified or recommended.

6.1 Proposed for 2023: Integrated Energy Data Resource (IEDR)

2022 Status	Proposed
2023 Status	TBD
Start Year	2023
Funding Approved Through	N/A
Description and Justification	PSEG Long Island will be participating in the IEDR platform initiative lead by NYSERDA. The objective of this state-wide centralized data platform is to inform investment decisions, promote innovation, encourage new business models, and enable better policy making and operational efficiency. NYSERDA has identified the initial 3-5 use cases that can be delivered quickly, have an immediate impact, and demonstrate the powerful potential of IEDR. In line with the NY Joint Utilities, PSEG Long Island will be providing available data sets following the phased implementation of the platform. Initial use cases are expected to be delivered in Q4 2022 and Q3 2023.

NYSERDA is leading an effort to develop an Integrated Energy Data Resource (IEDR) platform to satisfy the IEDR Order and deliver upon requested data access use cases. According to the Order[28]:

> *Releasing readily available energy-related data by means of useful access mechanisms will support New York in meeting its clean energy goals and facilitate the objectives of the Reforming the Energy Vision (REV) proceeding.1 The ability of market participants to deliver smart, economically sound energy solutions and the ability of customers to share their energy usage data, will animate markets, facilitate customer choice, and provide systemic benefits to all New Yorkers. In conjunction with useful data access, it is necessary to ensure that the proper protections of information technology (IT) systems, data systems, and customers' privacy exist.*

To support this effort, NYSERDA is engaging with various stakeholders spanning Energy Consulting, Federal and Local Government, Software Providers, State Agencies, Trade Associations, and Utilities in their effort to define and design the data platform.

As a participating utility in New York state, PSEG Long Island will provide data in support of the IEDR platform.

Objectives

PSEG Long Island seeks to support the visions of the Initial Public Version (IPV) and Minimum Viable Product (MVP), articulated by NYSERDA and the IEDR team[29], including:

- **IPV vision:** "create the foundation for a powerful and accessible data platform by launching 3 -5 use cases that appeal to key users of the IEDR, that are critical for subsequent use cases, that can be done well quickly, and that have immediate impact, as well as showcase the transformational potential of the IEDR by launching one powerful use case with a limited scope."[30]

[28] In the Matter of the Strategic Use of Energy Related Data. Order Adopting a Data Access Framework and Establishing Further Process. April 15, 2021

[29] A compilation of stakeholders assigned to lead the IEDR initiative inclusive of representatives from NYSERA, Deloitte, and Pecan Street

[30] IEDR Utility Data Deep Dive Workshop - Hosting Capacity Maps April 11, 2022 – IEDR Phase 1 Vision

- **MVP vision:** "create the go-to resource for multiple stakeholders working to achieve New York State's clean energy goals by rapidly iterating on the IPV and launching new use cases that provide end -to -end solutions for key challenges."

Scope

NYSERDA, in its position of leading the IEDR Team, has defined a multi-phase platform build approach that will include multiple releases per phase. The first phase is composed of the IPV deliverable in Q4 2022 and the MVP deliverable in Q3 2023.

The scope of delivering the IPV and MVP includes:

- Attending and participating in NYSERDA and JU workshops and meetings
- Identifying the prioritized use cases and data fields
- Defining the data fields
- Inventorying data field data source(s)
- Defining technical requirements
- Developing pipelines to the data source(s)
- Transforming the data into a format for submission to the IEDR platform as defined by the IEDR Team
- Testing the data files
- Developing a mechanism to send the file(s) at the frequency defined by the IEDR Team
- Defining validation mechanisms to confirm/identify if file(s) failed to send

6.1.1 Implementation Plan

IEDR scoping (for all utilities, not just PSEG Long Island and LIPA) is still underway and will not be known until late Q2 2022. The final delivery schedule and level of execution complexity will be highly dependent on the pace at which the IEDR team progresses in securing a platform provider, defining security protocols and progressing in developing, building, and testing the platform. From the details gained from the order, attending IEDR Team led working group sessions, and weekly Utility Coordination Group meetings, the current understanding of the execution schedule is summarized below.

Schedule

The implementation plan is divided into **3** main workstreams:

1. **Workstream 1: IPV**
   The first workstream will be focused on identifying, defining, and mapping the data fields and data sources that have been prioritized for the IPV. The desired outcome being the build, test, and delivery of the IPV data file(s).

2. **Workstream 2: MVP**
   The second workstream will be focused on identifying, defining, and mapping the data fields and data sources that have been prioritized for the MPV. The desired outcome being the build, test, and delivery of the MVP data file(s).

3. **Workstream 3: Collaboration & Communications**
   The third workstream will be centered on staying aligned with the Joint Utilities, NYSERDA and the IEDR team. In concert to the information gathered during the collaboration sessions, PSEG Long Island will develop relevant materials to inform customers and internal business units about the IEDR platform.

Table 6-1. IEDR Platform Project Schedule

Workstream	2022	2023
Workstream #1: IPV		
Complete NYSERDA Data Questionnaire(s)		
Inventory & map data fields for IPV use cases		
Perform data gap analysis		
Support creation/sharing of sample data file(s)		
Attend workshops with IT and Business SMEs		
Define technical requirements		
Support build/sharing of IPV data files		
Perform testing		
Send production file(s)		
Workstream #2: MVP		
Inventory & map data fields for MVP use cases		
Perform data gap analysis		
Attend workshops with IT and Business SMEs		
Define technical requirements		
Support build/sharing of IPV data files		
Perform testing		
Send production file(s)		
Workstream #3: Collaboration & Communications		
Attend UCG Meetings		
Attend NYSERDA Workshops		
Develop FAQ/Customer educational materials about the IEDR platform data sharing		

Customer Engagement and Communications

As NYSERDA will be the host entity of the IEDR platform, customer and stakeholder engagement and communications will be owned by NYSERDA. However, as custodians of customer data, PSEG Long Island will need to be prepared to address questions from customers about how the data is being shared, what data is being shared and what security measures have been put in place to ensure data privacy. PSEG Long Island will prepare FAQs and educational messaging for employees and customers based on guidance and information collected from NYSERDA and the IEDR Team.

Known Risks & Mitigations

Table 6-2 identifies potential risks and mitigations for the IEDR Platform.

Table 6-2. IEDR Platform Risk and Mitigation Assessment

Category	Risk	Mitigation
Technical	Unknown IEDR platform technology may result in integration issues and timeline delays.	Stay connected with the IEDR Team by attending workshops and meetings to remain informed of technology decisions and raise concerns as needed.
Project Management	The Data Analytics team is resource constrained and does not have a PM readily available to oversee the project.	Source the PM role externally.
Stakeholder Engagement	Business units have not provided insights to the data fields for the data analytics team to complete definition of technical requirements for build out	Engage business units in a series of working sessions to develop a data inventory and data source map that the Data Analytics team can then maintain for requirements definition.
Dependencies	Completion of development will require additional information from the IEDR Team about the data platform that is not yet available.	Stay connected with the IEDR Team by attending workshops and meetings to remain informed of dependencies.
Constraints	The development of the files to support the IEDR platform was not originally included in the 2022 work plan and thus resources were not originally allocated. There are limited resources on the Data Analytics team and any work on IEDR will result in reprioritization of already scheduled high priority work.	Request additional FTEs for the IEDR project.
Constraints	Some data elements that the IEDR Team is requesting to be made available to the IEDR platform are not currently shared or require password access. There is a risk that PSEG Long Island will not be able to provide all of the data being requested if the IEDR Team does not require any security verification or does not obfuscate sensitive information, particularly around substation location information.	The sensitivity of substation data is shared by all of the Utilities. The JU and PSEG Long Island are actively attending working sessions to talk through these topics.
Constraints	Some data elements do not exist in a source system. Instead, they are manually created through analysis. There is no way to upload them directly and with increased frequency of data sharing (the IEDR platform will expect monthly updates) this will put a strain on existing personnel to complete analysis more frequently.	The PSEG Long Island team will document verification and analysis processes associated with data creation and data availability to identify areas where automation is possible in order to minimize the workload impact on impacted business units.

6.1.2 Funding Request

At this point, information regarding the IEDR platform required data file format, final data field requirements, and deadlines for delivery are still being defined. Therefore, the capital budget estimates are based on the information collected to date including baseline budget estimates from the recent rate cases of several NY investor-owned utilities. In addition, LIPA will share in the platform service fees similarly to the Joint Utilities. The portion attributable to LIPA is approximately $1.6M. This cost is added to the 2023 capital dollar projections.

IEDR was not included in the 2022 workplan so there are no dollars allocated in the 2022 budget; however, the IEDR Team has defined the IPV as a deliverable in Q4 2022. As such, PSEG Long Island is supporting these efforts ahead of having additional funding approved for 2023.

Capital Expenditure

Table 6-3 showcases the Capital Expenditures planned for the IEDR Platform. The capital cost for 2023 include the platform service fees for NYSERDA attributable to LIPA. This contribution has already been committed to and approved by the LIPA board and solidified in a memorandum of understanding (MOU).

Table 6-3. IEDR Platform Capital Expenses

Funding Subcategory	Capital Expenditure ($M)
	2023
PM, Labor & Training	0.53
IT Labor	2.00
Third Party Support	0.40
IT Infrastructure	0.20
N/A	1.58
Total	**4.70**

Operating Expenditure

While the exact details of the IEDR platform solution are not yet defined there is an expectation that as part of developing the IPV, PSEG Long Island will have to stand up an intermediary cloud instance to enable delivery from the data sources to the IEDR platform. This intermediary platform will require annual operating and maintenance fees that will grow over time as more data is brought in to be supported.

Table 6-4 showcases the Capital Expenditures planned for the IEDR Platform.

Table 6-4. IEDR Platform Operating Expenses

Funding Subcategory	O&M Expenditure ($M)
	2023
IT Infrastructure	0.10
Total	**0.10**

6.1.3 Project Justification

IEDR is a state-wide initiative, in which all utilities, including investor-owned utilities, will participate; as such, a utility-specific BCA is not meaningful.

6.2 AMI Technology and Systems

2022 Status	Active
2023 Status	Operational
Start Year	2018
Funding Approved Through	2022
Description and Justification	PSEG Long Island met 145% of its annual goal with over 367,000 meters installed in 2021. By September 1, 2021, more than 95% of AMI meter installations were achieved, signaling the transition from full scale deployment to "clean up" phase. The opt-out rate was reduced from 0.57% at the beginning of 2020 to 0.45% by the end of 2021. The schedule for meter deployment is expected to remain on target for completion in 2022 as originally projected.

PSEG Long Island expanded its initial ~100,000 smart meters deployment to a full-scale deployment in 2019. The Utility deployed AMI across its service territory to maximize customer benefits and operational savings. Smart meters with AMI offer increased accuracy and enable new capabilities such as remote metering, automated move-in and move-out requests, and remote connect and disconnects. Implementing these capabilities are key components to unlocking the full benefit of AMI. PSEG Long Island planned to deploy more than 1.1 million smart meters between 2019 and 2022.

PSEG Long Island met 145% of its annual goal with over 367,000 meters installed in 2021. The opt-out rate was reduced to 0.45% at the end of 2021, a 21% improvement from the beginning of 2020. The Utility also met its mass deployment saturation levels and has begun close out of the project and transition to core operations.

In the November 26, 2021, DPS Recommendation Letter, Staff recommended that PSEG Long Island "…assess what would be required to allow for other utility equipment that are currently not communicating via fiber optic lines, to do so where fiber optic lines are installed for AMI. Where it is determined to be cost effective to connect other utility equipment to the fiber optic lines, PSEG Long Island should present a proposal for implementation starting in calendar year 2022."[31]

In response, PSEG Long Island is evaluating possible integrations with the existing fiber network. The majority of the PSEG Long Island substations utilize the fiber network for SCADA[32]. As part of the AMI deployment, collector units were installed in close proximity to existing substations. The team is planning to perform a pilot in 2022 to determine the feasibility of connecting a subset of AMI collectors to the fiber network as a backup to the primary 4G LTE network. The team will be monitoring impacts to network communications as well as NERC CIP compliance[33]. In terms of other grid assets, there are no plans to expand connection of the distribution automation equipment to the fiber network because these assets already leverage a dedicated private network that connects to the Advanced Distribution Management System (ADMS).

AMI is a foundational technology that enables additional products and services to be offered to customers. By taking a mass deployment approach, PSEG Long Island has increased the level of digital

[31] Matter 14-01299 State of New York Department of Public Service Interoffice Memorandum (November 26, 2021). Review and recommendations regarding the Long Island Power Authority and PSEG Long Island's 2021 Utility 2.0 Plan Annual Update and 2021 Energy Efficiency and Demand Response (EEDR) Plan.

[32] SCADA stands for Supervisory Control and Data Acquisition and is a form of control system architecture used to monitor and control networked devices

[33] NERC CIP compliance – The North American Electric Reliability Corporation has defined a set of standards for the protection of Critical Infrastructure that includes both physical and cyber security

equity in terms of data availability across businesses and households that can influence future customer offerings and empower customers with information about their usage patterns.

6.2.1 Implementation Update

See the scope and schedule updates below for AMI Meter Deployment.

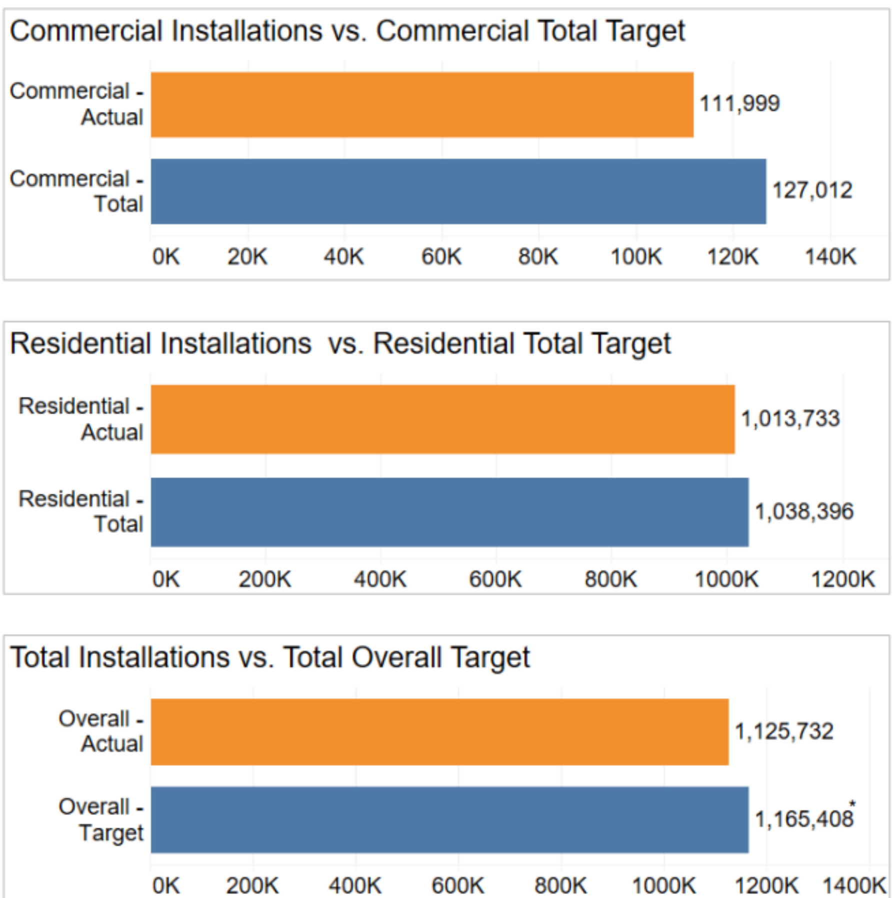
Scope Update

PSEG Long Island has deployed more than 1 million smart meters across its service territory to maximize customer benefits and operational savings (Figure). There is just over 3% of the original meter population remaining, which is inclusive of customer opt-outs.

Continuity during COVID-19

Despite the ongoing challenges of the COVID-19 pandemic, PSEG Long Island met 145% of its annual goal with over 367,000 meters installed in 2021 and over 1 million meters installed to date across its service territory.

Figure 6-1. AMI Actual and Target Installations as of March 31, 2022



PSEG Long Island will continue to deploy AMI meters through 2022 and transition to its post-AMI deployment operations for meter maintenance and operations.

Schedule Update

95% deployment was completed by September 2021, approximately 15 months ahead of the original deployment plan. Through Q1 2022 deployment reached 97%. The schedule for meter deployment is expected to remain on target and be largely completed in 2022 as originally projected.

6.2.2 Funding Reconciliation

In 2021 the AMI Meter Deployment budget was underspent as detailed in Table 6-5. A portion of the underspend was due to sufficient inventory reducing the need for additional meters to be purchased.

Table 6-5. AMI Meter Deployment Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019[34]	2020	2021	2022	Total
Capital	57.11	56.14	58.39	11.93	**183.56**
O&M	1.18	1.87	3.25	4.69	**10.98**
Total	**58.29**	**58.01**	**61.64**	**16.62**	**194.54**

Table 6-6. AMI Meter Deployment Capital and Operating Expense Variance

	2021	2022
Capital	6.89	(1.72)
O&M	(0.19)	(0.86)
Total	**6.70**	**(2.58)**

6.2.3 Performance Reporting

PSEG Long Island concluded 2021 exceeding Year-to-Date (YTD) and Program-to-Date benefit projections in the area of Avoided O&M Costs due to Reduced Labor Costs for Meter Reading and Meter Services. This was achievable by reallocating meter reading resources to the accelerated meter deployment effort.

In the area of Avoided O&M Costs due to Reduced Vehicle Costs for Meter Reading and Meter Services, 68% of YTD benefits were achieved and 72% of Program to Date benefits. Vehicle attrition lagged behind labor attrition due to the need to maintain fleet vehicles in order to adhere to COVID single occupancy restrictions and changing Center for Disease Control guidance.

Avoided Carbon Emissions are directly related to the rate of reduction of meter reading vehicles. Because the vehicle attrition rates lagged, the carbon emission benefits did not achieve projected levels. Benefit capture was also impacted by the make/model of vehicles varying from the original BCA. In 2021 41% of YTD benefits were achieved and 40% of Program-to-Date.

Lessons Learned

In 2021 COVID restrictions continued to introduce challenges to meter replacements for inside installations. And efforts continued to address locations requiring customer appointments, substandard conditions first requiring customer action, non-geographic spread across Long Island, and revisiting opt outs. Despite the challenges, PSEG Long Island was able to redeploy internal Meter Reader and Field Collections resources to accelerate meter deployments across the territory.

[34] 2019 spending includes costs incurred in 2018

Next Steps

The AMI Meter Deployment initiative has reached the completion stage. When the 95% saturation level was achieved in 2021, the business transitioned to a "clean up" phase and will be fully active in the post deployment phase in 2022. Meaning, they will be fully operationalizing the new capabilities and processes.

6.3 AMI Customer Engagement

2022 Status	Active
2023 Status	Operational
Start Year	2019
Funding Approved Through	2022
Description and Justification	The AMI Customer Engagement Plan was introduced in 2019 in parallel with full-scale AMI deployment to inform and communicate with customers throughout the process. The pre and post deployment of educational series and outreach to customers has been completed and meter opt-out rate has decreased over time and is currently at 0.45%.

The Customer Engagement program, introduced in 2019 with the launch of full-scale AMI deployment, aimed to inform customers of the AMI installation process and actively promote and incorporate feedback. In coordination with the AMI meter deployment schedule, PSEG Long Island is engaging and informing local communities about smart meter and AMI-enabled benefits through education sessions and marketing material to ensure customers can access the benefits. With the completion of the AMI deployment, the Customer Engagement program has completed the pre and post deployment educational series and outreach to customers who chose to opt out of AMI.

PSEG Long Island made sure to include a variety of different media to share educational materials with customers be it letters, postcards, bulletins, email, in person events, or website features there was a means for every customer to be touched by these communications. The communication plan involved specifically timed touchpoints relevant to the timing of the meter deployments within the customer's area included pre and post installment materials. This holistic approach ensure that no customer was left without means to access educational materials or information on the deployment plans.

6.3.1 Implementation Update

See the scope and schedule update below for AMI Customer Engagement.

Scope Update

In 2021 the AMI Customer Engagement team had many successes. In 2021, all three phases of the "MY – MyAccount" campaign were completed. The omni-channel media strategy intended to drive new enrollments and re-engagement with MyAccount and brought in over 22,000 new MyAccount users. Also, all phases of the AMI Energy Portal Customer Research, which included an online survey, was launched, and completed. The research findings will serve as a guide in developing upcoming communication/educational and customer engagement campaigns.

Within the 2021 DPS Recommendation Letter, staff recommended that PSEG Long Island include future plans for customer segmentation research. Segmentation research was completed at the end of 2021 and will continue to be updated to represent changing customer views and beliefs.

The development of the My Smart Energy Lab has been completed and is considered an operationalized asset, available for future PSEG Long Island Customer Engagement efforts.

Schedule Update

The global segmentation research was fully completed at the end of 2021 and from now on, it will be frequently updated to ensure it not only represents customer views and beliefs, but also fully meets their expectations.

6.3.2 Funding Reconciliation

Planned in person events and expenditures for materials were not realized due to COVID19 protocols resulting in an underspend of the 2021 forecasted budget as depicted in Table 6-6.

The original AMI business case defined a budget for Global Segmentation. Due to timing delays this work was not able to be executed in 2019 or 2020 and was initiated in the beginning of 2021. It was completed at the end of 2021 and enhancement of the research will be conducted in 2022 and future years as needed.

Table 6-6. AMI Customer Engagement Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	**2020**	**2021**	**2022**	**Total**
Capital	-	-	-	-	**-**
O&M	1.01	2.34	2.45	2.60	**8.39**
Total	**1.01**	**2.34**	**2.45**	**2.60**	**8.39**

Table 6-7. AMI Customer Engagement Capital and Operating Expense Variance

	2021	2022
Capital	-	-
O&M	0.37	(0.12)
Total	**0.37**	**(0.12)**

6.3.3 Performance Reporting

Through execution upon the comprehensive communication plan PSEG Long Island was able to maintain a very low opt-out rate that decreased over time and is currently at 0.45%.

Over the course of 2021 communications leveraged numerous channels to create hundreds of thousands of customer touch points:

Table 6-8. AMI Customer Engagement Performance KPIs

Channel	Customers Touched
Digital Communications (email only)	~250,000
Direct Mail (Letter, Postcard, Newsletter – Postage)	~350,000
MyAccount / MyAlert Campaign	~460,000
Marketing Campaign (Print, Media, Social Media, etc.)	All

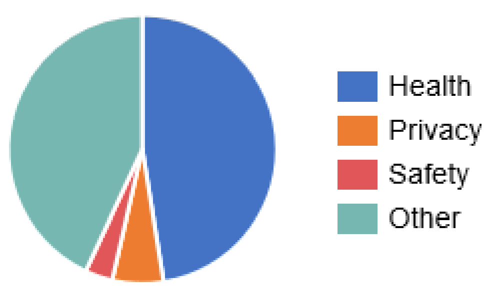
Lessons Learned

Throughout the life of the AMI Engagement plan, the focus has been to create a communication campaign supporting meter installation to educate and avoid pre or post-installation opt-outs. As more customers have smart meters installed, focus increasingly shifted towards post installation engagement around benefits and offerings due to AMI. Customers receive a variety of educational collateral (direct mail – letters, postcards, bulletins, and email) to increase their knowledge of the AMI benefits, including follow-on encouragement to explore the customer portal two months after installation. This focus and execution of the plan aligns with the following mission elements cited in the Annual Customer Experience Report:

- Developing and executing a customer service strategy which informs, serves, and satisfies customers
- Providing high quality, accurate and timely responses to customer requests
- Providing communication tools for service by phone, in person, and through various forms of technology such as web and social media

The communication mechanisms initiated in 2019 continued in 2020 and 2021 with some modifications due to the ongoing COVID-19 pandemic to ensure the safety of PSEG Long Island staff and those that they interface with in government. Social distancing and CDC recommendations continue to be closely adhered to. Requests for in-person meetings as well as utilization of "My LIPA IR-2021-12-22-0017A Page 4 of 6 Smart Energy Lab" are reviewed and provided only if public health guidelines and social distancing can be maintained. These efforts combined with execution of the engagement plan, as a whole, have enabled PSEG Long Island to maintain a continuously decreasing opt out rate. The opt-out rate started at 0.77% in 2019, decreased to 0.53% in 2020 and as of Q3 2021 has further reduced to 0.45%.

Figure 6-2. Reasons for Smart Meter Installation Opt Out Q1 2019- Q4 2021



Next Steps

The AMI Customer Engagement effort was defined in direct support of the AMI Meter Deployment initiative. As the meter deployment is operationalized, so will the customer engagement efforts. The team will continue to support the post deployment communication campaigns through 2022 and build communication campaigns into their business-as-usual plans for future years, such as new customer move-in educational materials about AMI meters and annual messaging for opt-out customers. Ongoing AMI communications will be similar to the direct marketing and Mass Media advertising currently in market, which highlight the benefits and capabilities the new technology delivers, as well as the Opt Out communications that were launched in June 2022.

6.4 AMI-Enabled Capabilities

2022 Status	Completed/Continuous Improvement
2023 Status	Operational
Start Year	2019
Funding Approved Through	2022
Description and Justification	To capture the full benefits of smart meter deployment, additional capabilities that leverage data made available by AMI are being implemented across Long Island. The existing implemented AMI-Enabled Capabilities initiatives will be operationalized in 2023. Future AMI Enabled capabilities will be assessed as part of the stage gate process in the 2023 filing and 5 year planning process.

PSEG Long Island's Utility 2.0 roadmap includes the phased implementation of capabilities that use the data from smart meters for data-driven insights. Some examples of PSEG Long Island's AMI-enabled capabilities include the following:

- <u>Revenue Protection:</u> Solutions that reduce theft of service and decrease energy losses, including automating disconnect and reconnect capabilities through Remote Connect Switch (RCS).
- <u>Outage Management:</u> Assess status of reported outages by "pinging" individual AMI-enabled meters to determine if the customer has been restored. This is done both for storms and non-storm outages to avoid truck rolls.
- <u>Customer Experience Tools:</u> Software tools offered to customers, including multiple account energy aggregation, energy-saving tips, energy use benchmarking, and enabling third-party access to customer energy data with customer consent and awareness.

Revenue Protection:

Remote meter reading, conducted for all AMI metered customers, provides increased meter reading accuracy that has associated revenue protection benefits. As stated in Section 2.1, PSEG Long Island enabled the AMI Remote Control Switch (RCS), i.e., the remote connect and disconnect capability in the first quarter of 2020, automating the move-in and move-out process. The launch of this capability was successful and included a robust process for addressing situations when communication with the meter cannot be established remotely, known as exception handling. By the end of 2020 the remote reconnect after disconnect for non-pay (cut on) process was completed. RCS capability use has continued successfully through 2021 and into 2022 and has become a business-as-usual operation.

Outage Management:

Outage Management related upgrades and integrations transitioned out of U2.0 in 2021 and are being managed through operating budgets.

Customer Experience Tools:

Customer experience tools have had the most emphasis to date under AMI-Enabled Capabilities and focus heavily on improving customer experience through the following key initiatives:

- The C&I Portal enables PSEG Long Island to engage commercial customers with personalized energy insights through the web portal and email reports. The portal offers commercial customers new insights like energy-saving tips and energy use benchmarking. Customer-facing applications will allow PSEG Long Island to better engage business customers with personalized energy insights through digital channels.
- To further enhance customer experience, Pick Your Due Date is a program that allows customers to pick their own billing cycle allowing them to better manage the timing of their bill payment. Made possible by automated meter reading capabilities removing dependency on manual meter reading schedules, this optionality is an added customer benefit. Timing for Pick Your Due Date will be evaluated during the 2023 planning process.
- The Next Best Action (NBA) recommendations have been rolled out via email alerts to a large-scale pilot group of over 200,000 residential customers. The NBA recommendations have also been embedded in the internal energy management tools available to PSEG Long Island Call Center Representatives for all residential customers.

6.4.1 Implementation Update

See the scope and schedule updates below for AMI-Enabled Capabilities.

Scope Update

The Customer Technology team was primarily dedicated to storm resiliency improvements throughout 2021. This reallocation of resources reduced the availability to enhance the features within AMI Enabled Capabilities and the focus was shifted to ongoing support, which was minimally required.

In 2022 the team will be delivering RCS and enhancements to alerts utilizing AMI technology.

The RCS enhancements will be split into 2 phases to enable remote turn offs for collections. The first phase will consist of development of a web form for remote turn off request submission. The second phase will include building an interface with OMS. This scope update is in alignment with the 2022 LIPA PIPs.

The team will be expanding the customer alerts scope of the Next Generation project utilizing AMI disaggregated data. Alerts will include EV TOU, balanced billing, and opt out budgeting as well as expanding the CSR-facing functionality to include insights for all PSEG Long Island residential AMI customers.

Schedule Update

The existing implemented AMI-Enabled Capabilities initiatives will be operationalized in 2023. Future AMI Enabled capabilities will be assessed as part of the stage gate process in the 2023 filing and 5 year planning process.

6.4.2 Funding Reconciliation

Due to the shift in resources, costs within the AMI Enabled Capabilities initiative in 2021 were primarily driven by software licensing. The budget was underspent as depicted in

Table 6-9.

In 2022 PSEG Long Island anticipates continued software licensing fees and support labor costs. There will be funding required to expand the cloud SaaS Next Generation Insights platform functionality. $450,000 of Capital will go toward building new alerts. $545,000 of O&M will provide the ability to send alerts to an additional 30,000 electric vehicle customers and an additional 100,000 balance billing customers. This cost will also expand the CSR-facing functionality to include energy disaggregation information for all PSEG Long Island residential AMI customers.

Table 6-9. AMI-Enabled Capabilities Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	3.53	2.67	0.20	2.30	**8.70**
O&M	0.26	0.61	1.01	2.83	**4.71**
Total	**3.79**	**3.28**	**1.21**	**5.13**	**13.41**

Table 6-10. AMI-Enabled Capabilities Capital and Operating Expense Variance

	2021	2022
Capital	4.01	1.74
O&M	0.86	(0.19)
Total	**4.87**	**1.55**

6.4.3 Performance Reporting

Performance for Revenue Protection and Outage Management in 2021 is summarized below.

Revenue Protection:

AMI-enabled remote disconnects continue to prevent unbilled revenue loss. Remote Control Switch (RCS) allows the Utility to disconnect service promptly after a requested move-out instead of waiting a day or more for manual power shut-off. Revenue protection capabilities expanded through 2021 with continued partnership with the data analytics team. Functionality was added to the data analytics dashboard to identify revenue loss through which PSEG Long Island was able to optimize the utilization of RCS. As part of the 2022 scheduled enhancements, the remote cut off process will be completed, rounding out the system.

Remote disconnect capabilities enabled 84% achievement of the 2021 YTD target for Revenue Loss Avoided during Move-in/Move-out Program to Date benefits metrics equates to 82% of the originally forecasted benefit. In addition, approximately 35% of the persisting theft identified was by using data analytics. Theft and tamper savings are estimated based on two different values:

- **One-time debit benefit:** When revenue loss due to theft or tampering is detected, the back-billed dollar amount is assigned as benefits to the year in which the money was collected. This is a one-time benefit for each instance of detected theft associated with previously consumed electricity that would have otherwise not been paid for.
- **Ongoing avoided theft benefit:** Theft or tampering that is detected using AMI would have continued to persist into the future, resulting in avoided future revenue loss. Before AMI, PSEG Long Island's theft detection capability was solely based on manual processes. It is estimated that these cases would have otherwise persisted longer into the future if it were not for AMI and data analytics capabilities.

Outage Management:

Similar to revenue protection, AMI data informs data analytics outage dashboards which report out on outages on the division, feeder, fuse, and transformer level. The dashboards are separate from the Q2 2022 efforts to integrate the AMI and OMS. These dashboards are part of the Data Analytics platform that use AMI data as a source for reporting purposes. Through these dashboards, PSEG Long Island analyzes AMI data to gain additional visibility on outages during storm events and project total outages. Detailed outage information enables the Utility to proactively manage storm response and avoid unnecessary truck rolls. Through Q1 2022, use of the AMI system data resulted in more efficient dispatching, reduced customer callback time, and avoided crew supervisor time from reduced truck rolls. This also benefited customers by reducing customer hours interrupted by improving crew availability time resulting from avoiding unnecessary truck rolls.

Next Steps

PSEG Long Island has developed foundational digital platforms that leverage AMI data to create unique capabilities and experiences for both external customers and internal employees. These platforms have been launched, stabilized, and enhanced to a point that they can transition to an ongoing support model typical of business-as-usual for the Customer Technology team.

6.5 Data Analytics

2022 Status	Active
2023 Status	Operational
Start Year	2019
Funding Approved Through	2022
Description and Justification	The benefits of the Data Analytics program, which leverages insights from AMI data, continued to grow with the increased installation of smart meters. Currently over 210 terabytes of data are stored, and more than 1 billion AMI meter readings are processed each day.

PSEG Long Island launched the Data Analytics Program in 2019, creating a new enterprise-wide capability that provides actionable insights. Over the last 3 years, this capability has been embedded in the Utility’s business and structured around several AMI-enhanced use cases. Through data collection and analysis, every department has the opportunity to improve operations for the Utility and benefit customers.

Foundational to the success of data analytics is the cloud-based data analytics platform called the Data Lake. The core platform of the Data Lake was implemented in 2019; it now stores over 210 terabytes of data, with over 1 billion AMI meter readings (across all meter channels) processed daily. The Data Lake is growing fast with the ongoing AMI meter deployment and the development of new data analytics use cases.

The Data Analytics team partners with departments across PSEG Long Island to select use cases and deliver value in collaboration with business champions. Much of the focus for 2021 was on storm response analysis which encompassed building solutions for business continuity planning (BCP), storm remediation and communications. In 2021 the team successfully launched the BCP solution for use of AMI data during storm events and completed the Revenue Integrity use case for Advanced Consumption. As a result of the team’s efforts, the Data Analytics program achieves greater visibility and communication of key storm metrics across PSEG Long Island business units, thus increasing awareness, efficiency, and consistency in the dissemination of critical information during a storm.

6.5.1 Implementation Update

See the scope and schedule updates below for the Data Analytics Program.

Success Snapshot

The Data Lake (cloud-based platform) currently stores over 210 terabytes of data with over 1 billion AMI meter readings processed daily.

Scope Update

The Data Analytics program continues to deliver functionality and enhance automated processes across multiple use cases. In 2021 the program completed the Revenue Integrity use case for Advanced Consumption by leveraging AMI data and completed the BCP solution for use of AMI data to identify outages related to Major Accounts during storm events. The Advanced Consumption use case predicts accounts that may be utilizing energy without an active account and when an account will reach/exceed a set threshold. The team has also recently completed the Situational Awareness dashboard, providing a consolidated view of key storm related updates for the organization.

AMI Based BCP Storm Restoration Use Case:

In 2021, PSEG Long Island launched a storm response solution that supports T&D Operations as part of its business continuity plans. Dashboards were developed by the Analytics and T&D business teams to allow operators to view AMI-reported outages that roll up by transformer, fuse, or circuit level so that they can manage the storm restoration effort. Build out of the BCP Dashboard satisfied several business needs:

1. Insights into what has been restored and what remains to be restored
2. The ability to perform an electronic circuit sweep to ensure full restoration
3. The ability to validate that outages are recognized and restored, regardless of whether or not the customer called
4. The ability to determine the current state of the distribution network based on AMI meter data

To address these needs the team built a collection of dashboards that provide distribution grid asset status (i.e., fuse, transformers, and meters) as well as multi-level outage information and the scattered outage report that includes all devices. Through adoption of the dashboards and report by T&D operations, PSEG Long Island was able to improve crew dispatch efficiency, accelerate storm restoration, and reduce truck rolls. Specific benefits associated with outage benefits is included in Section 1.4.

Advanced Consumption Use Case:

In the first quarter of 2020, PSEG Long Island enabled the AMI remote connect-and-disconnect capability. This capability automates customers' move-in and move-out process. The remote connect-and-disconnect capability delivers savings by avoiding onsite visits and advanced consumption. The Advanced Consumption Dashboard, built in 2021, utilizes AMI data to track and visualize the advancing consumption accounts and inform PSEG Long Island's Revenue Integrity Team. Build out of the Advanced Consumption Dashboard provides the following direct benefits to the business:

1. Decreased revenue loss by addressing advanced consumption cases sooner
2. Detection of resolved cases allowing resources to focus on true advancing cases

3. Identification of remote functionality allows for an expedited process

4. Increased turn off frequency

This year the team will also begin working on the AMI Theft Detection project. The purpose of the AMI Theft Detection project is to improve the identification of potential occurrences of energy theft based on the AMI meter information available. By increasing the ability to identify potential cases with analytics, the final analytical solution will add benefits to the business and drive the effectiveness and efficiencies of a data-driven method to detect revenue loss. The Revenue Integrity department will utilize the solution to assist in the determination of usage anomalies in an effort to pinpoint revenue loss that would have otherwise persisted. The project end state will consist of an analytical solution that can be leveraged to identify remotely suspicious patterns of energy use. Any potential cases will be forwarded to the field organization and investigated accordingly. The results of each investigation will be captured and tracked to assist in the determination of the success rate associated with the use case.

Other Use Cases:

In 2022 and beyond, PSEG Long Island will undergo the effort to develop a Standardized Data Access Platform. This will begin by developing a Master Data Analytics Project Plan and Phase 1 is expected to be launched this year. This work effort is outside of the U2.0 scope and will impact the availability of team resources. This reinforces the need to increase internal team staffing.

In parallel, the team will continue to build upon the outage reporting momentum from 2021 by completing the build out of the Situational Awareness dashboard in the first half of 2022. As of Q1 2022, the team has completed Phase 1 of the Situational Awareness dashboard providing a consolidated view of key storm related updates for the organization on customer outages, job incidents and proactive communications status. Crew/Resource and material status information will be added in the next phase.

In addition, the team will begin working on a Non-Wires Alternative Use Case. Currently, PSEG Long Island utilizes a modeling tool for evaluating potential deferred investment opportunities. The tool requires data inputs from multiple data sources. The Non-Wires Alternative Use Case will create a single source of data with centralized, curated data sets. The curated data sets will be available to use within PSEG Long Island's modeling tool, introducing efficiencies in the non-wires alternatives analysis process.

Schedule Update

The Data Analytics initiative will be operationalized in 2023.

6.5.2 Funding Reconciliation

The 2021 budget was underspent due to dedication of the Data Analytics team to storm and outage reporting work, which was not charged to the U2.0 budget. The team also experienced unexpected attrition which reduced the number of available resources for building out new use case solutions. However, the team was able to supplement resources and continue support and enhancement of existing use cases.

The team expects to increase hiring in 2022 with a goal of increasing headcount to the full compliment. This will enable work on prioritized use cases to continue into 2023.

Underspend totals are available within Table 6-11.

Table 6-11. Data Analytics Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	2.08	1.53	0.16	1.23	**5.00**
O&M	0.08	0.78	1.37	1.85	**4.08**
Total	**2.16**	**2.31**	**1.53**	**3.08**	**9.08**

Table 6-12. Data Analytics Capital and Operating Expense Variance

	2021	2022
Capital	0.73	-
O&M	0.25	0.23
Total	**0.98**	**0.23**

6.5.3 Performance Reporting

Data Analytics has contributed to the detection of theft/tamper cases and reduction of No Trouble Found truck rolls.

Lessons Learned

Throughout 2021, the team looked for ways to improve timeliness, accuracy, and reliability of data pipelines. The enhancements made to the architecture, data pipelines and scalability of the framework have paid dividends for future use cases.

Next Steps

In 2022 the team will continue to refine use cases that have completed initial development to better serve the business and customer.

In addition, the team will continue to work through remaining use cases, including Customer Communications BCP and Stata – Python migration (NWA).

6.6 Next Generation Insights

2022 Status	Active
2023 Status	Operational
Start Year	2020
Funding Approved Through	2022
Description and Justification	The Next Generation Insights initiative is intended to improve customer engagement via a suite of proactive digital communications containing personalized insights based on an energy disaggregation platform. The solution encompasses self-serve and CSR-enabled functionality. 2022 will be an evaluation year to determine the path forward for customer and CSR experiences.

PSEG Long Island has a foundational suite of energy efficiency, billing and payment, and home energy management education and awareness programs. With this foundation, customers have started to better understand opportunities to save energy and money; however, the typical usage alerts can be challenging for customers to associate a potential cost saving to the energy usage information.

The Next Generation Insights Pilot demonstrates how AMI interval data and machine learning can be used to gain deeper energy insights. By delivering personalized cost breakdown by appliance with specific tips and next best action recommendations, customers are provided with increased opportunities for sustained behavior changes.

The Next Generation Insights Pilot is conducting testing to evaluate customer engagement via a suite of proactive email communications as well as self-serve and CSR-facing energy management tools. PSEG Long Island believes that the energy disaggregation approach will be the key component to unlocking personalized customer insights based on actual usage of major appliances in the home. Appliances leave fingerprints or signatures on the whole home energy waveform. This Next Generation Insights service uses market-available pattern recognition and machine learning to extract and classify these appliance fingerprints. This foundational disaggregation associates the delivery cost of usage throughout the month and assigns costs to appliance categories to provide customers with meaningful relatable insights.

6.6.1 Implementation Update

See the scope and schedule updates below for Next Generation Insights.

Scope Update

The overall scope of Next Generation Insights has not changed since the 2021 Filing. The pilot has been increased to 200,000+ enrolled customers as stated in the 2021 Filing (2.5.3). The suite of customer alert emails has been expanded to include Next Best Insight, providing customers with rebates on home improvement products and appliances that improve the energy efficiency of their homes. This email alert is in addition to the existing electric usage by appliance alert, mid-bill projection of electricity usage alert and opt-in budget alert.

CSR-facing complimentary Next Generation Insights platform functionality is under evaluation in the call center.

Schedule Update

Next Generation Insights suite of proactive email alerts continue to go out to customers as scheduled while the call center and technology teams evaluate and test the CSR-facing functionality. Next steps will be decided after findings are assessed post pilot.

Evaluation of Next Generation Insights focuses on the energy savings and peak demand reductions attributable to the behavioral change. Results will be captured in 2022 and reported out in the 2023 filing.

6.6.2 Funding Reconciliation

Next Generation Insights spending was below budget in 2021, as depicted in

Table 6-13. The underspend is due to shifting O&M non-labor funds from delays due to Storm Isaias in 2020 to 2021. An additional spend was added to the 2021 budget to cover costs incurred by expanding the email alert suite, the CSR-facing functionality pilot and includes costs for the EM&V plan.

Funding is required for 2023 to close out the 3-year contract with the third party cloud SaaS provider. The shift in the funds is from the contract execution happening in early 2020 as opposed to the expected 2019 execution, resulting in final payment being due in 2023.

Table 6-13. Next Generation Insights Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	
	2019	2020	2021	2022	Total
Capital	-	0.56	-	-	**0.56**
O&M	-	0.23	1.03	1.02	**2.28**
Total	**-**	**0.79**	**1.03**	**1.02**	**2.84**

Table 6-14. Next Generation Insights Capital and Operating Expense Variance

	2021	2022
Capital	0.20	-
O&M	0.62	0.06
Total	**0.82**	**0.06**

6.6.3 Performance Reporting

In 2021 PSEG Long Island worked with project stakeholders to discuss and solidify metrics reporting methodologies. Customer satisfaction and call volumes will be captured throughout 2022 for benefits reporting in 2023.

Lessons Learned

Next Generation Insights is in an evaluation period. Once the pilot has been completed, PSEG Long Island will assess the feasibility and value of incorporating the costs of scaling Next Generation Insights to more customers and training all CSRs on the CSR-facing functionality within the Base Operating Budget. This assessment will include the metrics in the "Scope Update" Section as well as qualitative feedback from call center pilot CSRs. Lessons learned in this evaluation period include scoping out SSO functionality as a business requirement when setting up the initial project.

Next Steps

2022 will be an evaluation year to determine the path forward for the Next Generation Insights external customer experience and internal CSR experience.

6.7 C&I Demand Alert Pilot

2022 Status	Active
2023 Status	Active
Start Year	2022
Funding Approved Through	2022
Description and Justification	The C&I Demand Alert Pilot will test to what extent a real-time demand alert with actionable insights helps commercial customers manage energy costs that are incurred through demand charges. The exploratory period of the pilot will take place through 2022 and the execution period of the pilot will take place beginning in 2023.

PSEG Long Island believes that its C&I customers should have the ability to better manage energy costs incurred through demand charges. C&I Demand Alert is aimed at helping commercial customers on rate 280 avoid exceeding the demand threshold resulting in roll over to rate 281, helping customers who have already been rolled over to rate 281 switch back to 280 (or rate 285 to 281) and helping customer set a self-defined demand threshold designed to empower the customer to control their own costs and consumption.

C&I Demand Alerts provide value to customers in the form of reduction of demand charges or avoidance of increased demand charges. Demand charges can constitute between 50% and 60% of the delivery portion of a commercial customer's bill. The alerts will put greater awareness and ability to control demand in the hands of commercial customers, leading to long term improvements in customer satisfaction. For PSEG Long Island, benefits of C&I Demand Alerts would lessen demand during peak hours.

PSEG Long Island will initiate a pilot to test a vendor supplied solution.

Pilot Assumptions:

- Non-residential/business customers lack timely information on demand use.
- Non-residential/business customers want proactive communications about how to lower their demand to save money and avoid being switched to another rate
- Non-residential/business customers will engage with proactive communications
- Real-time alerts will not provide enough lead time for the customer to take an action and adjust operational drivers of demand usage

6.7.1 Implementation Update

See the scope and schedule updates below for the C&I Demand Alert Pilot.

Scope Update

The scope of the C&I Demand Alert Pilot has been modified since originally proposed in the 2020 Utility 2.0 Filing. The updated proposed hypothesis and methodology are detailed in the scope section.

The exploratory period will have three distinct phases: scope, define and generate. To validate the process, PSEG Long Island will conduct benchmarking and best practices prior to finalizing the targets, as described below. Marketing and outreach efforts will not begin until 2023, once the solution has been fully scoped and designed.

Scope the problem: This stage will focus on defining the ultimate impact that C&I Demand Alerts are intended to have on customer experience. Additionally, PSEG Long Island will identify the context and constraints faced when trying to solve for the problem addressed by C&I Demand Alerts and confirm hypotheses that can be used to define the C&I customer experience. PSEG Long Island will use industry benchmarks to guide the design of the hypotheses. PSEG Long Island has identified the following initial hypotheses to be explored:

- By providing timely alerts and educational materials, PSEG Long Island expects participating non-residential customers to increase awareness around their ability to manage demand in near-real time.
- By providing timely alerts and educational materials, PSEG Long Island expects X% of participating non-residential customers that are within X% of the demand threshold to avoid being transferred to a higher rate
- By providing timely alerts and educational materials, PSEG Long Island expects X% of participating customers to provide a 'Satisfied' or 'Highly Satisfied' rating in response to customer surveys

Gather data & analyze stakeholders: This stage will focus on information gathering and helps define the breadth of stakeholders, internal and external, who are either contributors to or recipients of the eventual solution. PSEG Long Island will gather feedback from internal groups that interact with customers as well as external customers. Questions to consider include, but aren't limited to:

- What information needs to be gathered to test the hypotheses? Define what conclusions can be drawn from existing sources of data and analysis and what conclusions need to be tested by collecting and analyzing new data.
- Which stakeholders need to be heard to ensure that the future solution accomplishes the goal of solving the C&I customer problem?
- Evaluate the internal and external solutions that can be leveraged with alert delivery.

Generate criteria: In this stage, PSEG Long Island will take a holistic view of which hypotheses were proven true and how they interact and what data points most strongly relate to desired outcomes of the C&I Demand Alert project. Additionally, PSEG Long Island will develop functional criteria necessary to include in a solution and define metrics that correspond directly to measuring the desired outcome of each functional criteria.

After completing all three of the steps, PSEG Long Island will be able to engage with vendors and vet solutions based on the defined criteria. When vendors have shown that their solutions fulfill all criteria necessary to accomplish the goals of C&I Demand Alert, PSEG Long Island will be able to confidently choose a solution to best serve C&I customer needs.

Schedule Update

Pilot Execution:

- 2022 Objectives:
  - The exploratory period of the pilot will take place through 2022. The primary objectives will be:
    - Defining requirements and process maps
    - Analyzing customer usage patterns to identify population sizes and customer characteristics that would benefit from proactive outreach about demand use.
    - Evaluating the feasibility of building an in-house data analytics solution vs. evaluating quotes from 3rd party solutions and technical architecture mapping
    - Defining pilot sample size and alert logic
    - Defining marketing and outreach strategy
- 2023 Objectives:
  - The execution period of the pilot will take place beginning in 2023:
    - Design, build and launch pilot
    - Inform internal stakeholder groups impacted by the pilot and offer training as needed
    - Execute the marketing and outreach plan
    - Monitor customer engagement metrics
    - Capture customer feedback and lessons learned
    - Assess pilot expansion options

Risks and Mitigations

The potential risks and proposed mitigation steps for implementation of the C&I Demand Alert pilot are outlined in Table 2-3.

Table 2-15. Risk and Mitigation Assessment – C&I Demand Alert Pilot

Category	Risk	Mitigation
Scope	The timing delays and resource availability requires adjustment to the implementation approach of the pilot.	Due to the length of the delay, the pilot will be reassessed and the team will use AMI usage data to analyze usage patterns to determine the best path forward for delivering value-added alerts for C&I customers.

6.7.2 Funding Reconciliation

The C&I Demand Alert Pilot effort has not yet launched. The deferred implementation will allow an amount of the budget to be used in 2022 to conduct research and explore solutions and defer the rest of the budget and spend accordingly to 2023, but total forecasted spending has not changed.

Table 6-16. C&I Demand Alert Pilot Capital and Operating Expense Budget and Forecast

	Actual	Actual	Actual	Updated Forecast	Request	Projected (Not Requested)	Projected (Not Requested)	
	2019	2020	2021	2022	2023	2024	2025	Total
Capital	-	-	-	0.25	1.52	0.00	-	**1.78**
O&M	-	-	-	-	0.10	0.11	-	**0.21**
Total	**-**	**-**	**-**	**0.25**	**1.62**	**0.11**	**-**	**1.99**

Table 6-17. C&I Demand Alert Pilot Capital and Operating Expense Variance

	2021	2022	2023	2024	2025
Capital	-	(0.25)	0.25	-	-
O&M	-	-	-	-	-
Total	**-**	**(0.25)**	**0.25**	**-**	**-**

6.7.3 Performance Reporting

This effort does not have any projected direct benefits. However, through a combination of real-time alerts and actionable insights for demand management, PSEG Long Island believes the C&I Demand Alert capability will help C&I customers reduce their demand charges.

Over the course of the pilot, PSEG Long Island will measure and report the following metrics:

- **Demand reduction:** Measure the demand of the participating customers on a regular basis and compare expected demand versus actual demand, noting alert events.
- **Customer satisfaction:** Deploy a survey designed to gauge customer sentiment for the customers participating in the pilot.

7. Utility 2.0 Portfolio-Level Summary Tables

7.1 Funding Requested for New and Active Utility 2.0 Initiatives

Table 7-1 summarizes the updated funding request for proposed and active projects, broken out by Capital and O&M expenditures. As this Filing is representative of a one-year outlook only, funding requests reflect 2023 only. Estimated spending forecasts are provided for 2024-2025, however, these outer years will be revisited in next year's filing. Detailed budgets for each initiative with costs organized by funding subcategory (for new projects only) can be found in Chapters 3-6. Note – 2022 spending is estimated through year end and includes YTD spending.

Table 7-1. Funding Request for Active and Proposed Projects

		Capital Expenditure ($M)				O&M Expenditure ($M)				
		Request	Projected			Request	Projected			
	Funding Subcategory	2023	2024	2025	3-Year Total	2023	2024	2025	3-Year Total	3-Year Total Request
Proposed	**EV & Storage Hosting Capacity Maps**	1.94	0.00	0.00	**1.94**	0.00	0.10	0.10	**0.20**	**2.14**
	IEDR Platform	4.61	1.83	1.83	**8.27**	0.10	0.40	0.60	**1.10**	**9.37**
	Residential Energy Storage System Incentive	0.00	0.00	0.00	**0.00**	1.20	1.00	0.00	**2.20**	**2.20**
Active	**C&I Demand Alert Pilot**	1.52	0.00	0.00	**1.52**	0.10	0.11	0.00	**0.21**	**1.73**
	Connected Buildings Pilot	0.00	0.00	0.00	**0.00**	0.08	0.00	0.00	**0.08**	**0.08**
	DER Visibility Platform	3.31	0.17	0.17	**3.65**	0.06	0.07	0.08	**0.21**	**3.86**
	EV Make-Ready Program	2.56	3.21	4.76	**10.53**	7.41	12.68	25.87	**45.96**	**56.49**
	EV Program	0.00	0.00	0.00	**0.00**	2.74	2.56	3.11	**8.41**	**8.41**
	Grid Storage (Miller Place)	6.29	2.23	0.00	**8.52**	0.00	0.92	0.19	**1.11**	**9.63**
	Suffolk County Bus Make-Ready Pilot	0.00	0.00	0.00	**0.00**	0.04	0.00	0.00	**0.04**	**0.04**
	Super Savers (Patchogue)	0.00	0.00	0.00	**0.00**	0.79	0.00	0.00	**0.79**	**0.79**
	Total	**20.23**	**7.45**	**6.76**	**34.43**	**12.52**	**17.84**	**29.95**	**60.31**	**94.74**

7.2 Budget Variance for Ongoing Utility 2.0 Initiatives

PSEG Long Island reconciled actual spend in 2021 with the approved budget that was filed for each of the approved initiatives through the 2021 Utility 2.0 Plan. The Utility also re-forecasted the budget for all ongoing initiatives for the period between 2022 and 2025 with the exception of operationalized initiatives, which were only re-forecasted to 2022.

Table 7-2 shows the variance between the approved budget and the actual and updated projected spending from 2021-2025 and Table 7-3 shows the variance by project broken out by year. Initiative-level details for the actual spend and the forecast are included in Chapters 3-6. Please note, as in other variance tables throughout this document, negative values reflect an actual or projected overspend of the previously filed budget.

Table 7-2. Variance Between Approved Budget and Updated Project Spending

2023 Status	Project	Capital ($M) 2021 Budget 2021-2025	Capital ($M) Updated Forecast 2021-2025	Capital ($M) Total Capital Variance	O&M ($M) 2021 Budget 2021-2025	O&M ($M) Updated Forecast 2021-2025	O&M ($M) Total O&M Variance	Total Variance
Active	**C&I Demand Alert Pilot**	1.78	1.78	**0.00**	0.21	0.21	**0.00**	**0.00**
Active	**Connected Buildings Pilot**	0.00	0.00	**0.00**	0.64	0.65	**(0.01)**	**(0.01)**
Active	**DER Visibility Platform**	3.95	8.06	**(4.11)**	0.22	0.20	**0.02**	**(4.10)**
Active	**EV Make-Ready Program**	65.07	10.83	**54.24**	25.93	50.20	**(24.27)**	**29.97**
Active	**EV Program**	0.00	0.00	**0.00**	11.56	12.44	**(0.89)**	**(0.89)**
Active	**Grid Storage (Miller Place)**	11.99	15.37	**(3.38)**	1.07	1.11	**(0.04)**	**(3.42)**
Active	**Suffolk County Bus MR Pilot**	0.60	0.10	**0.50**	0.45	0.75	**(0.30)**	**0.20**
Active	**Super Savers (Patchogue)**	0.00	0.00	**0.00**	2.15	2.16	**(0.01)**	**(0.01)**
Operational[35]	**AMI Customer Experience**	5.59	0.87	**4.72**	2.97	2.37	**0.60**	**5.32**
Operational[35]	**AMI Meter Deployment**	75.48	70.31	**5.17**	6.89	7.94	**(1.05)**	**4.12**

[35] Operational budgets reflect only actual and forecasted spend in 2021 and 2022

AMI Outage Management	1.66	1.13	**0.53**	1.54	1.47	**0.07**	**0.60**
AMI Revenue Protection	1.00	0.50	**0.50**	0.00	0.00	**0.00**	**0.50**
BTM Storage Program[36]	0.00	0.00	**0.00**	0.00	0.00	**0.00**	**0.00**
Customer Engagement	0.00	0.00	**0.00**	5.30	5.05	**0.25**	**0.25**
Data Analytics	2.12	1.39	**0.73**	3.70	3.22	**0.48**	**1.21**
Hosting Capacity Maps Phase 3	1.70	0.01	**1.69**	0.92	0.42	**0.50**	**2.19**
Locational Value Study	0.00	0.01	**(0.01)**	0.06	0.03	**0.03**	**0.02**
Next Generation Insights	0.20	0.00	**0.20**	2.73	2.05	**0.68**	**0.88**
NWA Planning Tool	0.00	0.00	**0.00**	0.12	0.12	**0.00**	**0.00**
PMO	4.18	4.17	**0.01**	0.10	0.00	**0.10**	**0.11**
Rate Modernization	4.38	4.68	**(0.30)**	9.26	5.36	**3.90**	**3.60**
Utility of the Future	0.62	0.36	**0.25**	1.99	1.98	**0.01**	**0.26**
Total	**180.31**	**119.57**	**60.74**	**77.79**	**97.73**	**(19.94)**	**40.80**

[36] BTM Storage Program became operational in Q1 2022

Table 7-3. Annual Variance Between Approved Budget and Updated Project Spending

2023 Status	Project	Total Variance from 2021 Filed Plan 2021	2022	2023	2024	2025	Total
Active	C&I Demand Alert Pilot	0.00	(0.25)	0.25	0.00	0.00	**0.00**
	Connected Buildings Pilot	0.00	0.07	(0.08)	0.00	0.00	**(0.01)**
	DER Visibility Platform	0.00	(0.39)	(3.32)	(0.19)	(0.19)	**(4.10)**
	EV Make-Ready Program	2.59	8.36	13.59	7.40	(1.97)	**29.97**
	EV Program	0.13	(0.30)	(0.59)	(0.04)	(0.09)	**(0.89)**
	Grid Storage (Miller Place)	3.76	(1.38)	(2.45)	(3.15)	(0.19)	**(3.42)**
	Suffolk County Bus MR Pilot	0.00	0.20	0.00	0.00	0.00	**0.20**
	Super Savers (Patchogue)	0.32	0.00	(0.33)	0.00	0.00	**(0.01)**
Operational	AMI Customer Experience	3.77	1.55	0.00	0.00	0.00	**5.32**
	AMI Meter Deployment	6.70	(2.58)	0.00	0.00	0.00	**4.12**
	AMI Outage Management	0.60	0.00	0.00	0.00	0.00	**0.60**
	AMI Revenue Protection	0.50	0.00	0.00	0.00	0.00	**0.50**
	BTM Storage Program	0.00	0.00	0.00	0.00	0.00	**0.00**
	Customer Engagement	0.37	(0.12)	0.00	0.00	0.00	**0.25**
	Data Analytics	0.98	0.23	0.00	0.00	0.00	**1.21**
	Hosting Capacity Maps Phase 3	2.03	0.16	0.00	0.00	0.00	**2.19**
	Locational Value Study	0.02	0.00	0.00	0.00	0.00	**0.02**
	Next Generation Insights	0.82	0.06	0.00	0.00	0.00	**0.88**
	NWA Planning Tool	0.03	(0.03)	0.00	0.00	0.00	**0.00**
	PMO	0.11	0.00	0.00	0.00	0.00	**0.11**
	Rate Modernization	2.47	1.13	0.00	0.00	0.00	**3.60**
	Utility of the Future	(0.15)	0.40	0.00	0.00	0.00	**0.26**
	Total	**25.05**	**7.10**	**7.06**	**4.02**	**(2.44)**	**40.80**

7.3 Rate Impact Analysis

The rate impact on residential customers from both ongoing Utility 2.0 initiatives and the initiatives proposed for funding in the 2022 Utility 2.0 Plan is illustrated in Figure 7-1**.** PSEG Long Island expects on average a net reduction in residential bills through 2025 as a result of Utility 2.0 initiatives. A key driver for this net reduction is the savings expected to be realized through the implementation of the EV Make-Ready Program.

Figure 7-1. Residential Customer Bill Impacts from Utility 2.0 Initiatives

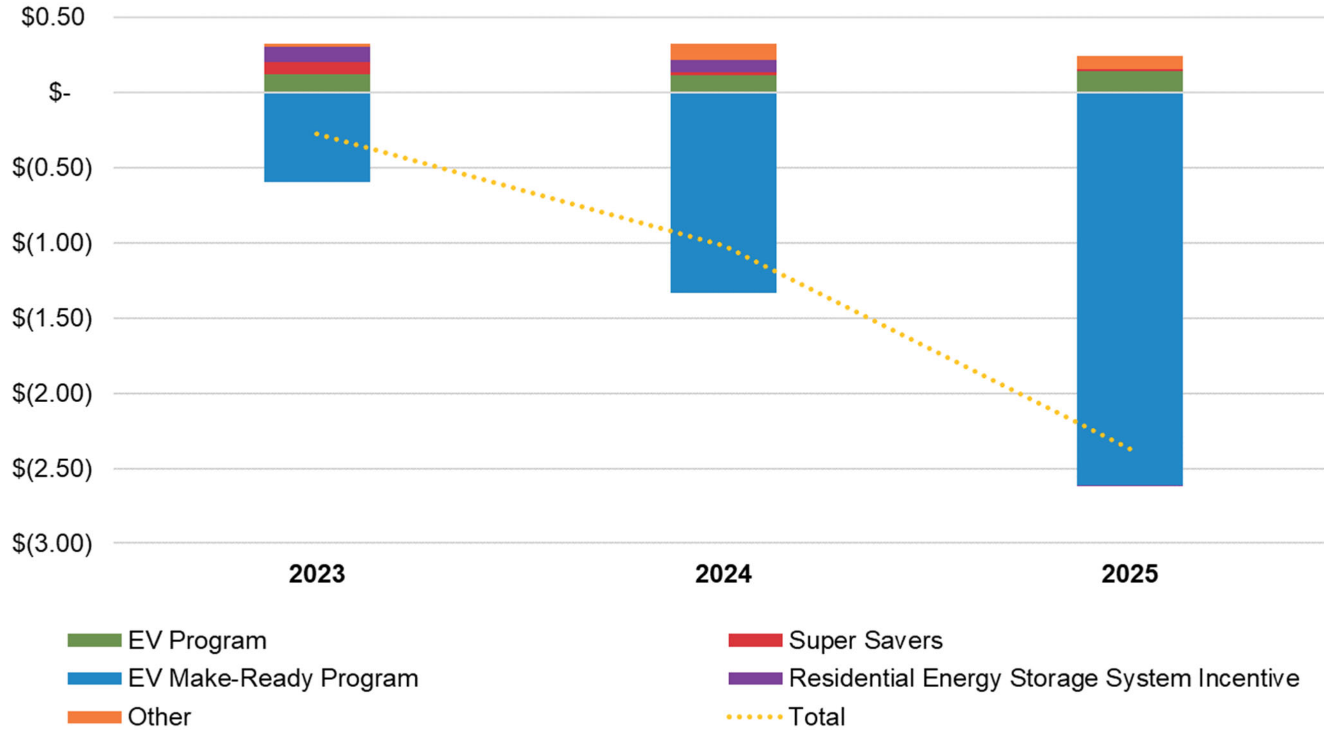


Table 7-3 and Table 7- illustrate the estimated rate impact on residential and commercial customers, respectively. These rate impacts reflect the capital, O&M, net revenue change, and power supply costs for each program, initiative and project included in the 2022 Utility 2.0 Plan's funding requirements, including both ongoing initiatives and new initiatives proposed in the 2022 Plan. Positive impact indicates an increase and negative impact a decrease in the rates.

Table 7-3. Residential Rate Impacts

Initiative	2023 ($)	2024 ($)	2025 ($)
C&I Demand Alert Pilot	0.00	0.01	0.00
DER Visibility Platform	0.00	0.01	0.01
EV Program	0.12	0.11	0.14
Utility-Scale Storage - Miller Place	0.00	0.05	0.02
Super Savers	0.08	0.02	0.02
EV Make-Ready Program	(0.60)	(1.34)	(2.61)
Connected Buildings Pilot	0.01	0.00	0.00
Suffolk County Bus Make-Ready Pilot	0.00	0.00	0.00
EV & Storage Hosting Capacity Maps	0.00	0.01	0.01

IEDR Platform	0.00	0.03	0.04
Residential Energy Storage System Incentive	0.10	0.08	(0.00)
Total	**(0.28)**	**(1.02)**	**(2.37)**

Table 7-5. Commercial Rate Impacts

Initiative	2023 ($)	2024 ($)	2025 ($)
C&I Demand Alert Pilot	0.03	0.07	0.03
DER Visibility Platform	0.02	0.10	0.10
EV Program	0.92	0.86	1.05
Utility-Scale Storage - Miller Place	0.00	0.46	0.17
Super Savers	0.04	0.01	0.01
EV Make-Ready Program	(4.86)	(11.27)	(22.66)
Connected Buildings Pilot	0.00	0.00	0.00
Suffolk County Bus Make-Ready Pilot	0.01	0.00	0.00
EV & Storage Hosting Capacity Maps	0.00	0.08	0.08
IEDR Platform	0.04	0.24	0.36
Residential Energy Storage System Incentive	0.00	(0.00)	(0.00)
Total	**(3.80)**	**(9.45)**	**(20.87)**

Appendix A. Energy Efficiency, Beneficial Electrification and Demand Response Plan

2023 Annual Update

Contents

A.1 Introduction

PSEG Long Island (the Utility) is a subsidiary of Public Service Enterprise Group Incorporated (PSEG), a publicly traded diversified energy company with annual revenue of $11 billion and operates the Long Island Power Authority's (LIPA's) transmission and distribution (T&D) system under a 12-year contract.

PSEG Long Island is submitting this Energy Efficiency, Beneficial Electrification, and Demand Response Plan (EEBEDR Plan) for review by LIPA and the New York State Department of Public Service (DPS). This submittal is in accordance with Public Authorities Law Section 1020-f(ee) and the Amended and Restated Operations Services Agreement dated December 31, 2013. PSEG Long Island seeks a positive recommendation on the Plan from DPS and funding approval from LIPA for 2023.

A.1.1 Portfolio Budget and Target Summary

PSEG Long Island's energy efficiency (EE), beneficial electrification (BE), and demand response (DR) programs make a wide array of incentives, rebates, and programs available to PSEG Long Island residential and commercial customers to assist them in reducing their energy usage and lowering their bills. PSEG Long Island has partnered with TRC Companies (TRC) to deliver the EEBEDR programs to the public. The proposed 2023 EEBEDR initiatives consist of programs for residential customers and multifaceted programs for commercial customers. Two recently introduced programs will continue as standalone programs in 2023: All Electric Homes and Multifamily. In addition, the Behavioral Initiative/Home Energy Management (HEM) program will continue. In 2020, in support of broader New York State policy objectives, PSEG Long Island's offerings were expanded to include rebates and incentives for installing EE measures that supply beneficial electrification to the grid and allow customers to save on their fossil fuel-based costs.

As part of its overall goal of reducing greenhouse gas (GHG) emissions by 40% by 2030, New York State set new statewide EE strategy in the New Efficiency: New York Order that was issued in 2018. In the Order, New York State establishes savings targets on an energy basis (Btu) for New York State as a whole and specifically for Long Island and establishes estimated reductions in forecasted sales by 2025 that would be the result of the actions described in the Order. New Efficiency: New York established fuel-neutral targets to accommodate beneficial electrification of buildings because increased electrification in the building and transportation sectors is necessary to achieve the State's carbon reduction goals.

PSEG Long Island has been actively engaged in rolling out utility-leading residential and commercial savings programs for customers. The 2023 EEBEDR Plan focuses on continuing to deliver EE savings programs to residential and commercial customers, while expanding efforts to include BE initiatives. Adopting fuel-neutral savings targets allows PSEG Long Island to aggregate efficiency achievements across electricity, natural gas, and delivered fuels such as oil and propane, which requires a shift toward investments in non-lighting opportunities, especially an expanded focus on heat pumps and other BE opportunities.

Early in program implementation efforts, PSEG Long Island recognized the importance of aligning the business trades with its program offerings. The residential portfolio promotes the ENERGY STAR message through its media campaigns, website, marketing materials, and outreach. In addition, collaboration with trade allies, state agencies, local utilities, and municipalities supports a coordinated effort to reach goals. These stakeholder partnerships facilitate attractive incentives and services to be offered through the residential programs, which make participants' homes energy efficient, safe, and comfortable.

PSEG Long Island's program philosophy and delivery is structured to respond to market changes and cost-effective EE opportunities during any given year. The Plan targets **900,730 total MMBtu savings** (which includes 234,534 MWh of EE savings), which are similarly reflected on a gross basis at site.

The proposed 2023 budget of $93.1 million for EEBEDR an increase over 2022's budget request of $88.9M. Much of this increase reflects an incremental increase of $7.5 million of additional funding towards energy affordability initiatives embedded within the budget. PSEG Long Island has budgeted for some initiatives that will not have any MMBtu savings associated with them in 2023—e.g., the Direct Load Management (DLM) Program at $1.5 million, as well as some NYSERDA collaboration that is expected to be a multi-year partnership with savings in subsequent years. Lastly, the budget includes a budget under Market Development to reflect funds that can be utilized to buttress existing programmatic efforts based on forthcoming studies or reports: LIPA's study on heat pumps (expected in the last quarter of 2022), NENY Mid-Term Review, and NYSERDA's statewide energy efficiency potential study.

Given the increased emphasis on advancing energy affordability by developing initiatives focused on energy solutions for low-to-moderate income (LMI) consumers, enhanced heat pump rebates and programmatic changes designed to enhance the Home Performance and Residential Energy Affordability Partnership (REAP) programs will total about $11 million in spending in 2023, more than double the amount in 2022. This includes substantial programmatic fund investments in income-qualified whole house heat pump rebates with the anticipation that current enhanced rebates from Attorney General Settlement funds will be exhausted prior to the end of 2023. These energy affordability initiatives are screened to ensure that energy burden impacts, such as the cost of running heat pumps, for LMI customers have been factored into any economics analysis as part of the decision to provide enhanced rebates towards these measures or programs.

PSEG Long Island will also continue to monitor the definition and tracking for disadvantaged communities (DACs), the definition of which is out for a public comment period at the time of this filing. The Marketing section that follows in this Appendix includes further details on how PSEG Long Island plans to target, educate, and perform outreach to defined DACs and individually income-qualified households.

New York State has set a statewide target of one million homes heated with highly efficient electric heat pumps by 2030 and an additional one million electrification-ready homes by that same year. Long Island's proportional share of the electrification goal would yield a target of 125,000 to 150,000 homes heated with heat pumps by the end of the decade, or an average of about 15,000 annual whole house heat pump deployments a year. While next year's filing is expected to show a multi-year heat pump push in line with these targets and PSEG Long Island's forthcoming Integrated Resource Plan filing, this year's filing shows directional alignment with that goal, building on the success PSEG Long Island has shown in deploying nearly 7,000 heat pumps across all types and sectors in 2021. In particular, in 2023 PSEG Long Island plans a greater level of stress on whole house heat pumps (including for income-qualified customers) and an increasing emphasis on pushing customers towards cold climate models while deemphasizing non-cold climate offerings.

PSEG Long Island continues to lead New York State in ongoing solar PV deployments. PSEG Long Island also continues to locally administer the NY-Sun Incentive Program for projects that receive Green Jobs – Green New York financing and Affordable Solar incentives for income-eligible households. Incentives are available for new residential and commercial projects that pair solar PV with energy storage, and those customers are also afforded enrollment opportunities in the DLM tariff to allow for capacity-based payments for system or local relief. The budget also reflects a small carryover of community solar projects that receive an incentive.

PSEG Long Island monitors program performance and consumer uptake on a continual basis. By doing this, the Utility can respond to changes in market conditions in a timely and efficient manner, which allows for the revision of offerings throughout the year in response to changing market conditions. Depending on the program, PSEG Long Island does an annual, quarterly, or monthly review to help respond to market conditions.

A.1.2 Portfolio Summary

Table A-1 summarizes the expected EE savings (on an MMBtu and MWh basis), along with the associated budgets, for the various residential and commercial components that comprise PSEG Long Island's portfolio of EE, BE, and DR programs.

Table A-1. 2023 EE and BE Goals

Program	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Energy Efficient Products	339,857	103,400	16. 9
Home Comfort	110,518	2,340	14.1
REAP (Low-Income)	10,884	2,020	1.9
Home Performance	31,426	1,906	7.5
Multifamily	8,928	1,839	0.79
All Electric Homes	1,038	28	0.15
Commercial Efficiency	286,309	90,242	38.9
HEM (Behavioral)	111,770	32,758	2.00
Total, Budget Components with Programmatic Savings	**900,730**	**234,534**	**82.21**
DLM Program	N/A	N/A	1.53
Market Development Fund	N/A	N/A	0.40
Clean Green Schools	N/A	N/A	0.05
PSEG Long Island Labor	N/A	N/A	3.20
Outside Services	N/A	N/A	2.16
Advertising	N/A	N/A	2.30
G&A	N/A	N/A	0.90
Community Solar	N/A	N/A	0.40
Total, Budget Components Not Associated with Programmatic Savings	**-**	**-**	**10.94**
Total	**900,730**	**234,534**	**93.15**

Table A-2 summarizes the expected budgets, participation, and savings (on an MMBtu basis) for the various residential and commercial heat pumps across PSEG Long Island's portfolio of programs. Full details on unit types and associated rebates and incentives can be found in the program sections that follow. Note that the savings and budgets listed below are subsets of the overall goals outlined in Table A-1.

Table A-2. 2023 Heat Pump Goals

Program	Savings (MMBtu)	Participation (Units)	Rebates & Incentives Budget ($M)
Heat Pump Water Heaters (Energy Efficiency Products only)	2,288	225	0.25
Heat Pump Pool Heaters (EEP)	29,439	1,000	1.1
Home Comfort Program – Whole House ASHPs	64,659	1,436	7.68
Home Comfort Program – Partial House ASHPs	41,882	2,415	1.41
Home Comfort Program - GSHPs	10,919	190	1.40
Home Comfort Program – Water Heaters	1,454	153	0.16
Heat Pumps (All Electric Homes Program)	925	30	0.07
Commercial Heat Pumps (Commercial Efficiency Program and Multifamily)	1,000	200	0.10
Total	**152,566**	**5,649**	**12.16**

Plans for 2023 also include substantial additional investments in energy affordability for customers through increased investments for LMI customers in energy efficiency programs and heat pump offerings. These investments in customer programs offer broad benefits, including: permanently lowering household energy bills, reducing carbon emissions, supporting Climate Justice, and reducing bill impacts on all customers. In 2022, PSEG Long Island planned for approximately $5M in spending on LMI customers across the Home Comfort, REAP, and Home Performance with ENERGY STAR programs[37]. As shown below, PSEG Long Island plans incremental spending of nearly $7.5M in 2023 for energy affordability.

Table A-3 summarizes the expected budgets, participation, and savings (on an MMBtu basis) for the various programs focused on income-eligible customers across PSEG Long Island's portfolio of programs. Full details on unit types and associated rebates and incentives can be found in the program sections that follow. Note that the savings and budgets listed below are subsets of the overall goals outlined in Table A-1.

Table A-3. 2023 Income-Eligible Customer Goals

Program	Savings (MMBtu)	Program Budget ($M)
Home Comfort – Whole House LMI	10,634	3.9
REAP	10,884	1.9
Home Performance - LMI	13,292	5.5
Marketing & Outreach	-	1.00
Total	**34,810**	**12.35**

[37] 2022 spending also included Attorney General settlement funds used for LMI whole house heat pump incentives, but these were not part of the base budget.

A.1.3 Benefit-Cost Analysis

While PSEG Long Island's EE planning is done on a gross basis at the customer meter to align with state objectives, the cost-effectiveness screening is still done on a net basis that takes into account potential free riders and spillover effects as a result of the program offerings.

PSEG Long Island has historically used two separate tests to screen each program and for the overall portfolio: the utility cost test (UCT) and the societal cost test (SCT). The tests are similar but consider slightly different benefits and costs in determining the benefit-to-cost ratios.

- The UCT includes the net costs of an EE or renewable program as a resource option based on the costs incurred by the program administrator, including all program costs and any rebate and incentive costs, but excludes costs incurred by the participant.
- The SCT considers costs to the participant but excludes rebate costs because these are viewed as transfer payments at the societal level. The SCT also includes the benefits of non-electric (i.e., gas and fuel oil) energy savings where applicable, resulting in different benefit totals than the UCT test.

To be consistent with the Benefit-Cost Analysis (BCA) Order that was issued in 2016, the rate impact measure (RIM) test is also conducted for each EE and renewable program and for the overall portfolio. The RIM test provides an assessment of the preliminary impact on customer rates and compares utility costs and utility bill reductions with avoided costs and other supply-side resource costs.

PSEG Long Island now uses the SCT as the primary method and has applied the June 2022 BCA Handbook (see Appendix B), including the avoided capacity and energy costs from including the carbon costs, to screen its 2023 EE programs and portfolio. The UCT and RIM tests are used as secondary reference points to assess the impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT.

Table A-4 presents the benefit-to-cost ratios for the SCT, UCT, and RIM tests for each program and for the overall EE portfolios. This includes LMI components that are part of various programs.

Table A-4. BCA for 2023 EE Portfolio

Program/Sector	SCT	UCT	RIM
Commercial Efficiency Program (CEP)	**2.07**	**1.37**	**0.18**
Multifamily	**2.03**	**0.82**	**0.17**
Commercial	**2.07**	**1.36**	**0.18**
Efficient Products	1.58	0.72	0.18
Home Comfort	1.23	-0.14	1.31
REAP	0.54	0.15	0.08
Home Performance	0.12	0.03	0.03
All Electric Homes	1.56	-0.11	2.12
HEM	1.25	0.88	0.22
Residential	**1.19**	**0.31**	**0.33**
Overall Portfolio	**1.52**	**0.79**	**0.22**

Table A-5 presents the benefit-to-cost ratios for the SCT, UCT, and RIM tests for each program and for the overall EE portfolios without the inclusion of the income qualified spending.

Table A- 5. BCA for 2023 EE Portfolio without inclusion of Income Qualified Spending

Program/Sector	SCT	UCT	RIM
Commercial Efficiency Program (CEP)	2.07	1.37	0.18
Multifamily	2.03	0.82	0.17
Commercial	2.07	1.36	0.18
Efficient Products	1.58	0.72	0.18
Home Comfort	1.39	-0.20	1.64
Home Performance	0.42	0.10	0.07
All Electric Homes	1.56	-0.11	2.12
HEM	1.25	0.88	0.22
Residential	**1.45**	**0.44**	**0.36**
Overall Portfolio	**1.72**	**0.95**	**0.22**

Table A-6 presents the benefit-to-costs ratios for the income qualified portions of the portfolio.

Table A-6. BCA for 2023 EE Portfolio – Income Qualified Programs

Program/Sector	SCT	UCT	RIM
Home Comfort	0.46	-0.03	0.36
REAP	0.41	0.11	0.07
Home Performance	0.04	0.01	0.01
Residential	**0.28**	**0.02**	**0.13**

Table A-7 outlines the levelized costs on an MMBtu-basis for each program.

Table A- 7. Levelized Cost Comparisons for 2023 EE Portfolio

Program/Sector	$/MMBtu
Commercial	**$7.09**
Multifamily	**$5.95**
Efficient Products	$3.95
Home Comfort	$8.93
REAP	$3.58
Home Performance	$57.99
All Electric Homes	$8.53
HEM	$17.87

Levelized cost reflects the total incentive divided by the total savings over the measure life.

A.1.4 TRC Companies Implementation

PSEG Long Island has partnered with TRC to deliver the Utility's EE and beneficial electrification programs. This partnership is governed by a master services agreement that has been effective since 2015 with Lockheed Martin, whose Distributed Energy Solutions group was acquired by TRC Companies in November 2019. TRC is a global consulting, engineering, and construction management firm that provides technology-enabled solutions to the power, oil & gas, environmental, and infrastructure markets. The scope of the master services agreement includes design and implementation of residential and commercial EE. TRC implements and manages most of the EE and BE programs offered under the PSEG Long Island brand. PSEG Long Island retains overall planning, budgeting, and advertising functions.

Program implementation includes ongoing analysis and continuous improvement of implementation methods, market conditions, and measure mix. Implementation also includes activities such as qualifying products, qualifying projects, validating project scopes, conducting pre- and post-inspections, processing rebates, issuing payments, engaging contractors, and training stakeholders. TRC provides customer service and technical assistance, including customer consultations, design collaboration, and customer support in developing energy plans and customized engineering studies. TRC is responsible for program analytics, including pipeline, product, and results reporting. TRC works in collaboration with the PSEG Long Island's program planning and evaluation team, participating in annual program evaluation and ensuring best practices are established and followed throughout the programs.

A.1.5 New Efficiency: New York

As part of its overall goal of reducing GHG emissions by 40% by 2030, New York set a new statewide EE target of 185 TBtu by 2025. Of the 185 TBtu goal by 2025, the New Efficiency: New York December 2018 Order established an incremental target of 31 TBtu of reduction by the State's utilities toward the achievement of the goal. Of the incremental target of 31 TBtu, LIPA was assigned a proportional share of increased EE savings of at least 3 TBtu over the 2019-2025 period, or 7.85 TBtu when combining base-level electric savings and the incremental amount established in the December 2018 Order.

Beginning with PSEG Long Island's 2020 EEDR Plan, offerings were expanded to include rebates and incentives for installing EE measures that supply beneficial electrification to the grid and allow customers to save on their fossil fuel-based costs. As such, Long Island became the first region in New York State to convert all electric savings metrics to an MMBtu basis to better conform with the New Efficiency: New York goals. This effort was supported by converting the entire PSEG Long Island Technical Resource Manual to calculate MMBtu for all measures offered.

As detailed further below, PSEG Long Island and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") have been developing a memorandum of understanding to support a more holistic and coordinated approach to deliver energy efficiency and beneficial electrification opportunities to shared customers on Long Island. The first part of this applies to market rate customers pursuing residential weatherization. Given current ongoing discussions about expanding the memorandum of understanding scope to include non-market rate residential customers and/or commercial programs, PSEG Long Island is proposing a slight modification to 2023 commercial savings to reflect the loss of natural gas savings, whereby PSEG Long Island's commercial programs would be calculated on an EE MWh savings at site metric with a straight conversion to MMBtu for the commercial programs. Residential programs would continue to reflect net MMBtus, per the above, as would any heat pump related efforts for commercial customers.

Adopting fuel-neutral savings targets allows PSEG Long Island to aggregate efficiency achievements across electricity, natural gas, and delivered fuels such as oil and propane, which requires a shift toward investments in heat pumps and other beneficial electrification opportunities. Shifting rebate and incentive opportunities to a fuel-neutral basis de-emphasizes electric (kWh) savings and, by consequence, EE savings as a percentage of overall load in pursuit of the primary target of reducing overall energy use on a TBtu basis. As PSEG Long Island and the market gain greater insights from implementing fuel-neutral programs, programs can be modified to target Btu savings rather than electric consumption or demand savings more effectively, which served as prior metrics.

A.1.6 Energy Savings Portfolio of Programs

Table A-8 lists the programs offered under this Plan that are administered by TRC and PSEG Long Island.

Table A- 8. Summary of EEBEDR Programs Offered by TRC and PSEG Long Island

Programs Administered by TRC	Programs Administered by PSEG Long Island
• Energy Efficient Products (EEP) Program • Home Comfort Program • REAP • Home Performance with ENERGY STAR (HPwES) • All Electric Homes • Multifamily • Commercial Efficiency Program (CEP)	• Behavioral Initiative (HEM Program) • DLM Tariffs

A.1.7 Evaluation, Measurement, and Verification

PSEG Long Island typically hires a third-party consulting firm to conduct annual program and portfolio evaluations of the EEBEDR programs as well as any ad hoc evaluation studies deemed necessary.

As part of the annual evaluation cycle, the third-party evaluator produces two volumes: Volumes I and II. Together, these volumes comprise the entire Annual Evaluation report. Volume I provides an overview of evaluation findings, including impact and process results for 2021. Volume II of the 2021 Annual Evaluation Report, the Program Guidance Document, provides detailed program-by-program review of gross and net impacts of the EEBEDR portfolios along with process evaluation findings and a discussion of data collection and analytic methods. The program guidance document is developed to provide PSEG Long Island and its implementation contractor, TRC, with data-driven planning actions moving forward and full transparency for the methods employed to calculate energy and demand savings. Annual evaluation reports consist of the following three overarching categories:

Impact Evaluation

- Determine energy, demand, and environmental impacts achieved from each EE and BE program.
- Conduct cost-effectiveness analysis for each EE and BE program.

Process Evaluation

- Assess how efficiently a program is being implemented by evaluating the operational efficiency of program administrators and contractors.
- Gap analysis conducted to identify strengths, opportunities, and improvements in program tracking data collections necessary for savings calculations and other evaluation processes and studies.

Economic Impact Analysis

- As part of their annual evaluation efforts, the evaluation team assesses the economic impacts of the EEBEDR portfolios' investments on the economy of Long Island.
- The third-party evaluator will provide 1-year and 10-year economic impacts estimates associated with the 2021 EEBEDR portfolio investments, where the 10-year economic impacts accrue from measures installed in 2021 over their remaining measure life.

A.1.8 Coordination with National Grid

The NENY Order that codified the energy efficiency and heat pump goals for New York also allows for greater opportunities for alignment around shared goals between utilities. PSEG Long Island and KEDLI are in the process of developing a memorandum of understanding to support a more holistic and coordinated approach to deliver energy efficiency and beneficial electrification opportunities to shared customers on Long Island. As KEDLI expands their own offerings to customers, particularly around market rate residential weatherization programs, PSEG Long Island is working with KEDLI to pursue opportunities to align the customer journey where possible. Beyond a smoother customer journey, the benefits to customers may also include the ability to provide coordinated incentives for defined measures or programs.

Through the Statewide LMI Portfolio, NYSERDA and KEDLI are aligning program design between their EmPower and HEAT programs to have the same offerings to create symmetry with the rest of the state. As part of this, the programs are leveraging administrative infrastructure to help simplify enrollment for customers that participate in HEAT and a NYSERDA-administered/HEAP funded retrofit and having the same program guidelines for contractors. In addition, PSEG Long Island and KEDLI are in discussions to expand this shared approach to savings and rebates for future measures or programs, particularly for income-qualified residential weatherization and/or commercial programs. An aligned program design between PSEG Long Island and KEDLI further streamline the administration of the NYSERDA-provided weatherization services provided on Long Island through HEAP Funds, further streamlining the administration of these funds.

As with market rate residential weatherization, KEDLI would claim natural gas savings and PSEG Long Island would claim electric (kWh) and other delivered fuel (if applicable) savings. Future points of collaboration may also include KEDLI offering a bonus incentive for customers who install whole house cold climate heat pumps and disconnect their gas account entirely. A partnership with KEDLI may help address the challenges faced by contractors working on Long Island who must navigate different program rules in the downstate region, which may create barriers and add cost burdens for those contractors who participate in both programs.

A.1.9 Marketing and Outreach

PSEG Long Island markets and advertises its EE programs with the goal of increasing:

- Awareness about the programs offered by PSEG Long Island.
- Participation in PSEG Long Island's EE programs.
- Customer satisfaction, ultimately leading to driving up J.D. Power scores.

Research by J.D. Power suggests that customers who are aware and participate in PSEG Long Island's programs tend to trust and think of the Utility more favorably. As part of its strategy to increase awareness of the Utility's EE programs, PSEG Long Island uses J.D. Power and its own demographic data to target media messaging through select channels aimed specifically at demographic segments including:

- Mass media (print, radio, TV)
- Tactical (emails, direct mails, newsletters)
- Targeted (digital, social media, Online Energy Analyzer)

These combined tactics help transmit a broad message about EE but also communicate the benefits of EE to niche sectors of the audience, such as age, income level, homeowner versus renter, and those more inclined to embrace green technology.

PSEG Long Island continues to push the message of “save energy and money.” Research conducted by PSEG Long Island indicated that customers want to hear from them most about how to save energy and money on their bill. Explaining to them that they have a choice when it comes to lowering their bill makes customer opinions toward PSEG Long Island more favorable.

PSEG Long Island believes the right media mix and frequency is important to enforce the message of EE. To reach households in Nassau, Suffolk, and the Rockaways, a mix of TV, radio, newsprint, digital banners, and occasional billboards on trains and buses are used. This mix ensures that a broad audience is being reached. When it comes to marketing actual programs such as Home Comfort, Geothermal, or Home Performance, PSEG Long Island uses a more tactical approach with targeted emails, direct mail, and digital ads.

Efforts promoting EE continue to achieve positive results. Customers who are “somewhat familiar” with EE programs/services rank PSEG Long Island 145 points higher in the J.D. Power survey. Over the last 4 years, PSEG Long Island has successfully implemented multiple campaigns into the market on the Home Comfort (formerly Cool Homes) and Geothermal programs, as well as overall EE awareness. These campaigns resulted in two TV commercials, four different radio spots, 12 print ads, dozens of social posts, four train/bus billboards, and 12 digital ads.

A.1.9.1 *Disadvantaged Communities*

PSEG Long Island is formulating a plan in consultation with its strategic marketing and advertising agency to support the Utility’s goal of delivering at least 35% of energy efficiency benefits to residential and business customers in disadvantaged communities or in income-qualified households. While the benefits accruing to disadvantaged communities are expected to be economy-wide investments that are broader in scope than just clean energy and energy efficiency programs, this Appendix is primarily concerned with the energy efficiency benefits.

In addition to the mass media advertising that PSEG Long Island uses to communicate the multiple benefits of its energy efficiency programs, in 2023 the plan will be to supplement that messaging with more local targeting though digital ads, social media, and specific community papers. In addition, PSEG Long Island may also look to do targeted traditional marketing collateral, such as direct mail, bill messages, and bill inserts.

Prior to implementing any campaigns or marketing collateral into market, PSEG Long Island will discuss internally across its strategic marketing agency and customer intelligence business if any additional segmentation or research is needed. Spanish translations for some collateral will be available for download from the PSEG Long Island website. The effectiveness of the campaigns will be monitored, measured, and optimized by engagements, site traffic, sales, energy efficiency conversions and any other KPIs that are established to help us meet goal.

In addition to marketing and advertising, communications, public affairs, and PSEG Long Island’s business customer advocates will also help in the ongoing outreach and awareness of the Utility’s energy efficiency programs.

A.2 Products and Programs

The following sections provide details on the programs that are being offered in 2022. Each section includes an outline of the program delivery channels, the target market, and the list of measures and incentives. Where applicable, details on outreach efforts and the cost-effectiveness of the program are also provided.

A.2.1 Energy Efficiency Products

The objective of the EEP program is to increase the purchase and use of energy efficient appliances, beneficial electrification equipment, and lighting among PSEG Long Island residential customers. The EEP strives for market transformation, increasing the market penetration of efficient products primarily by financially incentivizing consumers. These rebates and incentives are distributed either through direct consumer rebates in a downstream program or to manufacturers or retailers in upstream/midstream models.

The program provides rebates or incentives for energy efficient measures like ENERGY STAR-certified lighting, ENERGY STAR appliances, storm windows, heat pump pool heaters, advanced power strips, and water heating equipment. Rebates and incentives are offered through upstream and downstream promotions. ENERGY STAR certified products meet the energy efficiency standards set by the US Environmental Protection Agency and US Department of Energy. ENERGY STAR provides the program an independent third-party review and vetting of measures. As ENERGY STAR specifications change, PSEG Long Island adjusts its program offerings to remain in alignment, ensuring that program offerings meet the latest efficiency standards. In 2023, in recognition of the Energy Independence and Security Act (EISA) lighting standards, ENERGY STAR LED common lamps and specialty lamps will only be incentivized for the first six months of 2023. The rebate and promotion of battery-operated lawn care equipment will also be phased out in 2023.

In addition to financial incentives, the program educates customers about the benefits of using energy efficient products and beneficial electrification equipment in their homes and outdoor spaces through a variety of marketing channels. The PSEG Long Island EEP program supports the stocking, sale, and promotion of efficient residential products at retail locations within its service territory. To support New York State's greenhouse gas reduction goals, PSEG Long Island's metrics shifted to MMBTU reduction. Resultantly, in 2020 the EEP began promoting and incentivizing beneficial electrification equipment, along with the more traditional electric energy saving ENERGY STAR offerings. The program uses a variety of mechanisms, most notably financial incentives, to increase the market penetration of these energy efficient products and beneficial electrification equipment in their homes. These incentives are distributed either through direct consumer rebates or upstream/midstream incentives paid directly to manufacturers or retailers.

PSEG Long Island reviews and adjusts EEP program offerings in order to maximize customer engagement, incorporate new technologies trending in the industry, and to retire other measures from the portfolio when the market is saturated.

A.2.1.1 *Program Delivery*

The EEP program is delivered through partnerships between TRC, subcontractors, retailers, distributors/installers, and product manufacturers. Customers who purchase qualifying ENERGY STAR appliances and beneficial electrification equipment are eligible for rebates or point-of-sale incentives.

Upstream Incentives

Upstream incentives are payments to manufacturers or retailers to stock, promote, and sell ENERGY STAR-certified lighting products. PSEG Long Island is able to buy-down the wholesale price rather than the retail product price by directing the incentive to the retailer or manufacturer. This typically results in a greater reduction of the retail price. Retailer and manufacturer reimbursement is based on the submission and verification of sales data.

Markdowns focus on working directly with manufacturers and retailers to reduce the final retail price of specified products. A markdown is structured to provide a participating retailer a per-unit incentive for all sales of a particular product sold during a specified period.

In order to implement an upstream program, Program Agreements (PA) are required between appropriate parties, including the retailers and manufacturers. Several program agreements have been negotiated with lighting manufacturers and retailers to support the EEP. PA's provide a budget cap and number of products to be sold during a specified period. For each upstream promotion a PA is established that identifies:

- Model numbers and quantity of products to be promoted
- PSEG Long Island per-unit incentive
- Total allocated funding for the promotion
- Retail price for each specific product model during the promotional period
- Promotion duration including start and end dates
- Location of each retail store participating in the promotion
- Sales data reporting requirements
- Frequency of sales data submissions
- Marketing requirements, e.g., placement of PSEG Long Island-branded point of purchase (POP) materials

Processing Upstream Incentives

TRC's subcontractor partner is responsible for the following upstream rebate processing procedures:

- Obtaining point-of-sale (POS) data from retailers to confirm appropriate measures were incentivized and to track quantities, etc.
- Maintaining a database that can track sales data. Data must include fields like product name, store/retailer, date/time, promotional PA numbers, manufacturer. Data must be exportable to reports.
- Ensuring that incentives are paid only for eligible products sold through participating stores during an active promotional period
- Standardizing various sales reports supplied by different industry partners and into a central 6.7program database and, after reviewing and subjecting inputted data to various quality assurance checks, distribute funds to industry partners
- Issue incentive payment to manufacturers and retailers
    - Payments are issued twice a month
- Host an online catalog or marketplace where customers can purchase energy efficient products through the PSEG Long Island website

Twice monthly sales data is communicated to the EEP team who validates that the sales data accurately reflects program participation and requirements. On validation, the subcontractor is paid the sum of incentives.

Downstream Rebates

Processing Online Application and Mail-In Rebates
Downstream rebates are payments paid to end-use customers who purchased qualifying equipment and applied for a rebate. TRC processes all rebates but engages with an Implementation Contractor to

support the program by developing marketing collateral and promotions and establishing relationships and engaging with a large number of retailers to support the program. That engagement includes providing training to retailer and distributor sales staff on program participation and product eligibility, providing staffing for instore promotions and seeking opportunities for upstream promotion.

Processing Online Application and Mail-In Rebates
TRC provides a user-friendly Online Application (OLA) portal that allows customers to complete their rebate applications in a digital format. The OLA is integrated with the ENERGY STAR Qualified Product List which validates product eligibility that the customer is applying for. The OLA is also integrated with the Captures database which allows for the instant verification of a customer's CIS account number. After customer submittal of the OLA, the OLA migrates directly to Captures for review by the TRC processing team.

Under the umbrella of the EEP program, PSEG Long Island offers an Appliance Recycling program that is planned to continue through 2025. The goal of the program is to promote the removal of older, but operable and in use, inefficient appliances from the customer home/business. The program provides checks to residential and commercial customers who participate in the refrigerator/freezer recycling program, and vouchers for customers who participate in the dehumidifier recycling program. Vouchers can be used on the PSEG Long Island marketplace (Online Energy Efficient Products Catalog). The EEP program engages an appliance recycling subcontractor who is responsible for the removal and proper disposal of the recycled equipment.

Customers receive a $50 incentive for each refrigerator or freezer recycled. Customers can also earn an additional $35 voucher per unit for recycling up to three working room dehumidifiers in conjunction with a qualifying refrigerator or freezer pickup.

On behalf of PSEG Long Island, TRC subcontracts appliance recycling. Subcontractors have been vetted to ensure that they have experience providing the services offered and responsibly disposing of the appliances. Responsibilities include:

- Scheduling pickups from customer homes or businesses
- Verifying appliance qualifies for program
- Appliance removal from customer homes or businesses
- Rebate processing and payment (check/voucher)
- Program tracking and reporting against goals
- Identifying opportunities for improvement

The Program Manager engages the subcontractor to develop innovative and creative marketing strategies and materials. Marketing may include, but not be limited to, mailers, bill inserts, direct mail, e-blasts, flyers, website, print ads, and giveaway promotions.

The EEP model described above is intended to remain in place through 2025.

A.2.1.2 *Target Market*

All PSEG Long Island residential customers.

A.2.1.3 *Measures and Incentives*

Table A-9 lists the measures offered in the EEP program. Pool pumps will no longer be incentivized beginning in 2022 because of new DOE regulations that will go into effect in 2021. Please note, battery operated lawn equipment was removed from the 2023 program year plan due to feedback from the

Department of Public Service. The Planned Units for LED Lighting in 2023 have also been reduced by 50% due to the DOE ruling and updates to the Energy Independence and Security Act (EISA). The DOE ruling goes into effect in July 2023.

An Income Eligible Direct Install Smart Thermostat measure has also been added to the EEP program. This measure will be available to qualified REAP participants to support a holistic direct install customer journey.

Table A- 9. EEP: List of Measures

Measure	2023 Planned Units	Measure Incentives	Measure Rebates
SSL - specialty	1,200,000	$2.25	-
SSL - common (A19)	750,000	$1	-
Advanced Power Strips (Tier II)	500	$25	-
Most Efficient Clothes Washers	3,000	-	$50
Heat Pump Water Heater $\leq$ 55 gallons	150	$100	$1,000
ES Dehumidifiers - Midstream	5,000	$30	-
ES Room Air Purifiers (<150 CADR) - Upstream	1,250	$30	-
ES Room Air Purifiers (>150 CADR) - Upstream	750	$40	-
ES Dryer - Electric Resistance	2,500	-	$50
Advanced Power Strips (Tier I) - Mid-stream/Upstream	5,000	$15	-
Heat Pump Water Heater > 55 gallons	75	$100	$1,000
Most Efficient Dryers- Heat Pumps	100	$300	-
LED In-Storage	1	-	-
Smart Thermostats - Connected (Wi-Fi Enabled)- Midstream	12,000	-	$70
Smart Thermostats - Learning - Midstream	5,000	-	$100
Tankless Water Heater <12kW	90	$60	$100
Tankless Water Heater >12kW	45	$100	$300
Heat Pump Pool Heaters	1,000	$100	$1,000
LED Linear Fixtures - Midstream	16,000	$6	-
Solar Pool Cover	200		$75
Dehumidifier Recycle	150		$35
Refrigerator & Freezer Recycle Post 2001 & Pre 2014	2,000		$50
Refrigerator & Freezer Recycle Pre 2001	800		$50

A.2.1.4 *Outreach*

The EEP program for PSEG Long Island employs a variety of outreach strategies to ensure that customers are aware of the rebates/incentives available for ENERGY STAR appliances and beneficial electrification equipment and provides informative collateral on them. Strategies include broad brush and marketing via:

- Limited-time offer e-blast promotions
- Bill inserts
- Digital display ads
- Social media posts

- Point-of-purchase material at retailers
- Online Application
- PSEG Long Island website
- Online Marketplace

In addition, the program employs in-person outreach strategies including:

- Corporate lighting fairs
- In-store presentations
- Community partner outreach events
- Home shows in Nassau and Suffolk counties

These outreach strategies have proven effective in engaging and educating customers on the benefits of adopting ENERGY STAR and beneficial electrification products and they are planned to continue through 2025. Understanding the importance of digital transformation, the EEP program intends to increase social media presence to engage customers and promote the program.

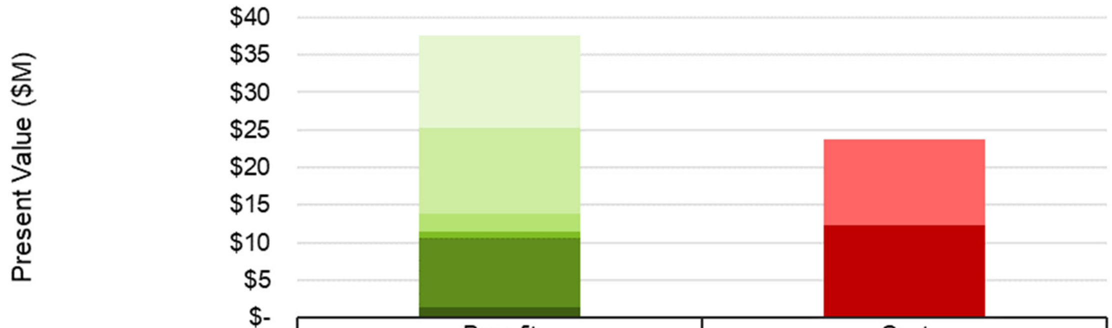
The TRC Program Manager works with the appliance recycling subcontractor to develop marketing collateral. The program uses palm cards to promote the program. They contain program details for TRC to distribute to customers at all public events and through other residential programs, such as REAP and Home Performance.

TRC and PSEG Long Island collaborate on social media posts and postcard mailings that educate the customer on proper recycling methods. TRC may also launch giveaway promotions to effectively increase participation.

A.2.1.5 *Business Case*

The EEP program has a SCT benefit-to-cost ratio of 2.25 and RIM benefit-to-cost ratio of 0.40. A list of the value streams considered in the BCA is detailed in Figure A-1.

Figure A-1. Present Value Benefits and Costs of SCT – Efficient Products



	Benefit	Cost
Fuel Switching Benefits	12.32	-
Net Avoided SO2 and NOx	0.000113	-
Net Avoided CO2	11.50	-
Avoided Distribution Capacity Infrastructure	2.28	-
Avoided Transmission Capacity Infrastructure	0.96	-
Avoided Energy (LBMP)	9.07	-
Avoided Generation Capacity Cost (AGCC)	1.51	-
Participant DER Cost	-	11.50
Program Administration Costs	-	12.36
Total	37.64	23.86

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	12.32	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.00	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	11.50	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	2.28	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.96	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	9.07	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	1.51	
8	**Participant Distributed Energy Resources (DER) Cost**	Includes cost of incremental equipment and installation.		11.50
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		12.36
	Total Benefits		**37.64**	
	Total Costs			**23.86**
	SCT Ratio		**1.58**	

NPV = Net present value
LBMP = Location-based marginal pricing

A.2.2 Residential Home Comfort Program

PSEG Long Island's Home Comfort Residential Heating and Cooling Program provides PSEG Long Island residential customers rebates for the purchase and installation of efficient and clean Air Source Heat Pumps (ASHP). ASHPs are typically two to three times more efficient than traditional fossil fuel space heating. The Home Comfort Program rebates efficient cold climate and non-cold climate ducted and ductless systems. In addition, the program offers rebates for system controls to ensure the ASHP is operating as the primary heating source.

Since 2019, the Home Comfort program has evolved each year to align more closely with New York State's aggressive greenhouse gas reduction goals, found in the Climate Leadership Community Protection Act (Climate Act). The Climate Act calls for an 85% reduction of GHG emissions by 2050. In the spring of 2019, PSEG Long Island rebranded the Cool Homes program to the Home Comfort program. The rebranding of the program was coincident with shifting the focus from cooling systems, like central air conditioning systems, to ASHPs and the proper use of them as a combined primary heating and cooling system. To promote ASHP technology, the Home Comfort Program launched an ASHP Pilot program that targeted electric resistance heating communities. The pilot boasted impressive engagement and installation results and laid the foundation for the Whole House ASHP offering, which hit the market in 2020. The whole house rebate offering was available to new construction customers and customers with existing fossil fuel heating systems. In 2020, central air conditioning systems were removed from the Home Comfort program offering. This program change increased the promotion of whole house and partial house ASHP solutions and better aligned the Home Comfort program with New York State's goals.

A whole house installation occurs when a customer sizes the ASHP to meet the heating and cooling needs of their entire home. A partial house installation occurs when a customer sizes the ASHP to meet a portion of the heating and cooling needs of their home. Customers with existing fossil-fuel heating who participate in the whole house offering are permitted to keep the existing system as a secondary heating source. To ensure the ASHP is the primary heating source, the Home Comfort program rebates, and requires, the installation of integrated controls. Integrated controls connect to both the ASHP and fossil fuel system and are programmed to default to the ASHP unless the temperature dips below a certain temperature, causing engagement of the fossil fuel heating system. With the exception of customers replacing electric resistance or an old heat pump, all other heat pumps are expected to provide fuel switching benefits to customers.

The Home Comfort program provides a participation pathway for all customers by offering market-rate and income eligible rebates for holistic energy efficient whole house solutions and partial house solutions. In April 2021, PSEG Long Island began promoting a new component of the Home Comfort program called “Home Comfort Plus”. The Home Comfort Plus program provides income eligible customers with enhanced rebates intended to cover a generous portion of a Whole House cold climate heat pump installation. To ease the path to participation for the public, the Home Comfort/Home Comfort Plus and Home Performance with Energy Star weatherization program are offered in one application. Customers can participate in Home Comfort, Home Performance with Energy Star or both programs at once. For low to moderate income participants, there is an enhanced rebate offer. Enhanced rebates are available for income eligible customers who install whole-house heat pumps and weatherization measures.

From initial program inception, and legacy Cool Homes program, the Home Comfort team has worked directly with partners, distributors, and manufacturers to educate and train them on program offerings and requirements. This level of engagement and collaboration ensures that all customers who interact with a member of the Home Comfort team or a trusted partner are educated on the benefits of ASHP technology and have the support to make energy efficient decisions for their home and family. ASHP technology can provide clean heating and cooling in a customer’s home for 10-25 years. Because of this, it is critical for members of the Home Comfort team and the partners to positively influence the customer on the benefits of program participation. PSEG Long Island works with Energy Finance Solutions (EFS) to qualify income eligible customers. Beginning in the 2023 program year, income eligible customers will be qualified utilizing 80% of the State Median Income. Historically, income eligibility was based on 60% of the State Median Income. To impact more income eligible customers, and promote whole-house solutions, expanding the income eligibility guidelines is necessary. Income verification documents like letters from the Home Energy Assistance Program (HEAP) or Social Security will continue to be accepted. EFS also offers low-interest on-bill recovery loans and smart energy loans for qualified market-rate and income eligible customers.

In 2023-2025, to continue supporting New York State initiatives, the Home Comfort program will update program requirements to remain in alignment with the state and NYSERDA. As the requirements around heat pumps are rapidly evolving as the market adjusts, rebate values, contractor incentives, and program guidelines will be re-evaluated quarterly to ensure offerings remain engaging and promote state objectives and program participation.

A.2.2.1 *Notable Changes*

In 2023, the Home Comfort application continues to offer rebates for heat pumps, controls, and Home Performance with ENERGY STAR weatherization measures. Beginning in 2021 and continuing through 2023, rebates will be available for ducted air source heat pump tune-ups, central air conditioner tune-ups, and electric hot water heating equipment (heat pump water heaters and tankless water heaters. Electric hot water heating equipment has typically been offered through the EEP program but including it in the Home Comfort application allows the partner and participant to consider all-electric solutions to meet their heating and water heating needs through one central application. New in 2023, an income eligible rebate will be available for ENERGY STAR Heat Pump Water Heaters.

In May of 2022, the Home Comfort program re-evaluated existing rebates for both market and income eligible customers, as well as equipment eligibility requirements. As a part of the evaluation process, the Home Comfort team also met with high volume participating contractors to understand the current market. As a result, the Home Comfort/Home Comfort Plus offering was updated as follows:

- To allow more cold climate models to be eligible for the program, the Home Comfort program aligned efficiency requirements with NEEP
- To standardize the customer experience, equipment categories and rebates were reduced to one category for Market customers and one category for income eligible customers
    - Rebates were also increased for both categories to stimulate the market
    - Income eligible rebates were increased by approximately 38% to cover closer to 70%-100% of the total project cost
- All Non-Cold Climate Equipment was removed from the application in order to promote holistic whole house cold climate air source heat pump solutions
    - Non-cold climate equipment is available for rebate through the Residential Online Application

All rebates continue to be based on the heating capacity of the equipment and calculated based on the 17°F rated heating capacity. Integrated controls continue to be required for all whole house and partial house cold climate systems where supplemental fossil fuel heating exists. The requirement for Manual J load calculations also remains constant with previous years and includes partial house cold climate ASHPs. A Manual J is required to ensure all equipment is properly sized for the home. These additional program requirements were included to better align the Home Comfort program with the rest of New York State.

An Equipment Only offering was launched in 2021 and continues to be available in 2023. TRC built a digital Equipment Only participation method through the already established Residential Online Application. Customers who wish to use a non-participating Home Comfort partner or who installed their own equipment, can apply for up to two per system rebates, every 5 years, for eligible non-cold climate ductless mini-split ASHPs and ducted ASHPs. The ducted ASHPs offering was added in May 2022. Through this equipment-only style offering, customers are not required to install smart thermostats, integrated controls, or provide a Manual J. The customer must provide an invoice and an AHRI certificate.

The Home Comfort program's income eligible offering continues to be available in 2022. Eligible customers can receive enhanced rebates for installing whole house cold climate ASHPs and weatherization measures. In April 2021, the program launched the Home Comfort Plus component of the low-income ASHP offering. PSEG Long Island received $4.5M in additional funding that was applied to the existing income eligible whole house rebates. The per ton rebate values became so generous that eligible income eligible customers would pay little, if any, out of pocket costs for the whole house system. The $4.5M in additional funding applies to whole house cold climate ASHPs only. In May of 2022, this offering was further enhanced to provide even larger rebates to cover 70%-100% of the total project costs. To accommodate this robust offering, the Home Comfort program enrolled additional Home Comfort Plus Partners to engage with the income eligible community.

To further impact the income eligible community, the income eligibility guidelines also became more generous. Historically, income eligibility was based on 60% of the State Median Income. Beginning in 2023, income eligibility for customers participating in Home Comfort, Home Performance with ENERGY STAR, and REAP will be based on 80% of the State Median Income to ensure more income eligible customers are aware of the offerings and can receive the multitude of benefits through program participation. Utilizing 80% of the State Median Income, aligns closer with the cost of living expenses on Long Island, as opposed to the 60% State Median Income. The financial landscape on Long Island is much different than the rest of New York State and the income eligibility guidelines should reflect that. Based on data sourced from the 2019 Census ACS[38] , the "Real Median Household Income" for Nassau

[38] https://www.deptofnumbers.com/income/new-york/nassau-county/

County was $118,453 and $106,228 for Suffolk County. The “Real Median Household Income” For New York State was $72,108 and $65,712 for the United States.

Historically, REAP was at 80% of Area Median Income (Nassau/Suffolk). PSEG Long Island understood that the rest of the State was moving towards a 60% of Statewide Median Income standard, but thought this was too rigid for Long Island, which has higher income levels and cost of living compared to the rest of the State. To still focus our efforts on income eligibility while taking Long Island’s higher income levels into account, we’ve decided to move from 80% of Area Median Income to 80% of Statewide Median Income for 2023. This will lower income thresholds compared to the historical average while still keeping local conditions in consideration.
Extending into subsequent years, PSEG Long Island plans to increase the adoption of heat pumps (along with home performance projects) in the single-family residential sector by establishing a partnership with Sealed, a New York-based company that finances key home improvements using the money homeowners currently waste on energy. For more details on the Sealed Partnership, see Section A.2.4.1.

A.2.2.2 *Program Delivery*

Home Comfort program participation is primarily driven through partnerships with installation contractors who, with vetting and training, become Home Comfort partners. Home Comfort partners promote the benefits of participation in the Home Comfort program and have positively impacted the ASHP market by adhering to PSEG Long Island’s quality installation verification (QIV) of ASHP equipment. Home Comfort partners are given the opportunity to collaborate with the Home Comfort team and receive education and training on program requirements regularly. TRC also hosts weekly contractor meetings to assist partners with all aspects of program participation through initial application review, equipment review, and technical requirements.

To further assist and engage with partners, PSEG Long Island provides Home Comfort partners with incentives to offset costs associated with equipment testing, like Manual J Load Calculation software. Providing incentives for equipment like software ensures partners will properly perform QIV installations and continue to participate in the Home Comfort program.

A Manual J is necessary for a QIV installation. Contractors perform Manual J calculations to ensure appropriately sized energy efficient units are installed. In addition to right-sizing equipment, the Home Comfort partners will ensure that the refrigerant charge and airflow are checked using prescribed tests. In 2023-2025, all heat pump projects will require installation by a QIV Home Comfort partner, with the exception of the equipment only offering.

Geothermal heat pumps are a component of the Home Comfort Program; however, geothermal projects are completed on the standalone Geothermal Rebate Application. The standalone application accommodates both Residential and Commercial projects. This is because most often, geothermal market partners service both residential and commercial customers. Rebate levels and contractor incentives are the same for both project types, but savings are driven by the selection of a residential or commercial installation. When an application is received, the customer type is validated by rate code and a site inspection. In 2021, geothermal water heating was added to the program offering. This allows a customer to install a whole house or whole site geothermal space heating and water heating system solution.

In May of 2022, like Home Comfort, the Geothermal rebate offering was also re-evaluated. The program launched an income eligible offering to reach those qualified customers who wish to pursue a Geothermal heat pump installation. The offering continues to be available in 2023, with the addition of an income eligible geothermal water heating offering. The income eligibility guidelines for the income eligible Geothermal offering will follow suite with the Home Comfort 80% State Median Income guidelines.

A.2.2.3 *Target Market*

The Home Comfort program, inclusive of Geothermal, is offered to all residential customers in the PSEG Long Island service territory. Enhanced LMI rebates are offered to all eligible customers.

A.2.2.4 *Measures and Incentives*

The list of measures that are offered in the Residential Home Comfort program are included in Table A-10.

Table A- 10. Residential Home Comfort Program: List of Measures

Measure	2023 Planned Units	Measure Incentives	Measure Rebates
Smart Thermostats - Learning - ASHP	100	-	$100
Smart Thermostats (Connected WI-FI enabled) – ASHP	30	-	$70
Integrated Controls	1,215	-	$500
Integrated Controls - LMI	188	-	$750
ASHP Tune Up	50	-	$50
CAC Tune Up	50	-	$40
ccASHP (QI) – Whole House Electric Baseline	125	$500	$3,002
ccASHP (QI) – Whole House Electric Baseline (LMI)	8	$500	$16,511
ccASHP (QI) – Whole House Fossil Fuel Baseline	1,000	$500	$3,002
ccASHP (QI) – Whole House Fossil Fuel Baseline (LMI)	186	$500	$16,511
ccASHP (QI) – Whole House New Construction	115	$500	$3,002
ccASHP (QI) – Whole House New Construction LMI	2	$500	$16,511
Ducted ccASHP (QI) – Partial House	100	$250	$859
Ductless ccASHP (QI) - Partial House	1,750	$250	$446
Ducted ASHP – Equipment Only ≥15 SEER & ≥8.5 HSPF	65	-	$150
Ductless ASHP – Equipment Only ≥18 SEER & ≥8.5 HSPF	500	-	$150
GSHP De-Superheaters	20	-	$250
GSHP Tier I	15	$200	$3,000
GSHP Tier II	150	$200	$6,000
GSHP Tier I LMI	5	$200	$16,500
GSHP Tier II LMI	20	$200	$16,500
GSHP Water Heater	15	-	$1,000
GSHP Water Heater LMI	3	-	$1,500
Heat Pump Water Heater ≤ 55 Gallons	60	$100	$1,000
Heat Pump Water Heater > 55 Gallons	40	$100	$1,000

Measure	2023 Planned Units	Measure Incentives	Measure Rebates
Heat Pump Water Heater ≤ 55 Gallons LMI	9	$100	$1,500
Heat Pump Water Heater > 55 Gallons LMI	6	$100	$1,500
Tankless Water Heater <12 kW	20	$60	$100
Tankless Water Heater >12 kW	40	$100	$300

A.2.2.5 *Outreach*

The Home Comfort program outreach strategy, aside from contractor word of mouth, includes a variety of public platforms:

- Internet keyword searches
- Banners on high traffic webpages, such as Newsday.com, Facebook.com, etc.
- Radio advertisements
- Newspaper advertisements
- Industry networking events and speaking engagements, such as AIA Peconic, AIA Long Island, Passive House New York
- Partnering with New York State's Clean Heat marketing and advertising
- Promotion on the PSEG Long Island webpage

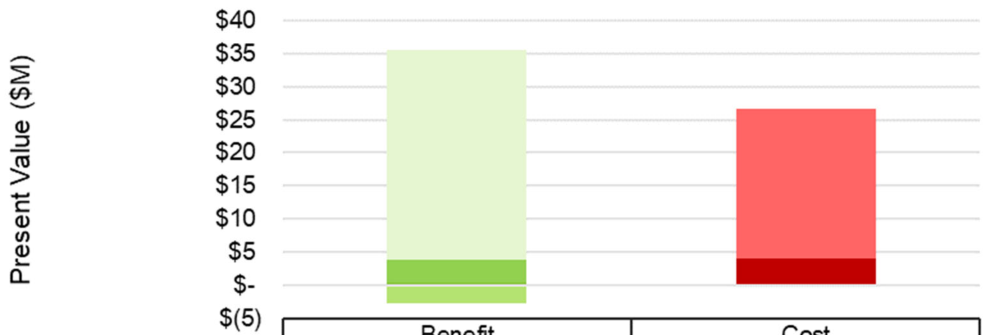
In 2023-2025, the Home Comfort team will continue to implement the above listed outreach strategies and work with participating contractors on tools to promote the installation of efficient heat pumps. In addition, the Home Comfort team will continue to develop more educational material to provide contractors and customers a better understanding heat pump technology and the benefits associated with the equipment.

It should be noted that during the 2020 pandemic period, the Home Comfort team, along with the Home Performance team, began offering virtual training sessions to maintain contractor engagement. The Home Comfort subject matter experts hosted open houses and webinars, providing a platform for contractors to learn more about important program components such as the methodologies behind Manual J Load Calculation and best practices. These types of trainings maintain high level of contractor engagement and ensure the contractors have the tools necessary to reach and engage customers. Due to very positive response from the market and partners, these virtual methods of engagement continue to be utilized.

A.2.2.6 *Business Case*

The Home Comfort program has a SCT benefit-to-cost ratio of 1.25 and RIM benefit-to-cost ratio of 1.34. A list of the value streams considered in the BCA is detailed in Figure A-2.

Figure A-2. Present Value Benefits and Costs of SCT – Home Comfort



	Benefit	Cost
Fuel Switching Benefits	31.58	-
Net Avoided SO2 and NOx	0.000344	-
Net Avoided CO2	3.41	-
Avoided Distribution Capacity Infrastructure	0.24	-
Avoided Transmission Capacity Infrastructure	0.10	-
Avoided Energy (LBMP)	(2.62)	-
Avoided Generation Capacity Cost (AGCC)	0.12	-
Participant DER Cost	-	22.62
Program Administration Costs	-	4.02
Total	32.84	26.64

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	31.58	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.00	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	3.41	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.24	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.10	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	(2.62)	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.12	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
8	**Participant Distributed Energy Resources (DER) Cost**	Includes cost of incremental equipment and installation.		22.62
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		4.02
	Total Benefits		**32.84**	
	Total Costs			**26.64**
	SCT Ratio		**1.23**	

NPV = Net present value
LBMP = Location-based marginal pricing

A.2.3 Residential Energy Affordability Partnership Program

The Residential Energy Affordability Partnership (REAP) program is a free program for income eligible customers that includes a home energy survey conducted by a certified Building Performance Institute (BPI) field technician, energy savings education and tips, and the direct install of energy efficiency measures. The REAP program encourages whole house improvements and provides customer support throughout the entire energy efficiency journey. Homeowners and renters are eligible for the REAP program. Key components of the REAP program are:

- Achieving persistent energy savings
- Encouraging energy saving behavior and whole house improvements
- Helping residential customers reduce their electricity bills
- Developing partnerships with contractors to bring efficient systems to market
- Marketing and cross-promoting other PSEG Long Island program offerings

A.2.3.1 *Notable Changes*

In the 2023 program year, notable changes include offering Smart Thermostat installations to customers, as well as an adjustment to the income eligibility qualification.

To provide more benefits to REAP participants, Smart Thermostats will be offered to customers as a direct install measure. The inclusion of this measure will enable REAP participants to better control their heating and cooling systems and influence their heating and cooling behaviors. The Smart Thermostats will also be enrolled in PSEG Long Island's Smart Savers program.

The income eligibility has also been updated for 2023 to reflect 80% of the State Median income, as opposed to the 80% Median Area Income. The purpose of this approach is to move towards the statewide income eligibility threshold while still addressing the higher cost of living in Nassau and Suffolk counties in comparison to New York State. This aligns with the income eligibility structure that will be implemented in both Home Comfort and the Home Performance with ENERGY STAR program, ensuring a consistent Customer experience throughout the portfolio of income-eligible Programs.

A.2.3.2 *Program Delivery*

PSEG Long Island and TRC engage a third-party implementation contractor to work with the REAP program team and eligible customers to efficiently meet energy saving goals while adhering to the program's budget. The REAP team and implementation contractor develop a targeted marketing plan for specific homes and areas. Factors included in identifying these customers are, high intensity usage, underserved regions or populations and specific need profiles such as income eligible. Customers who are identified through these efforts are offered a free comprehensive home energy survey and energy savings educational materials. These materials and free energy survey are intended to influence the customer in REAP program participation.

Customers who are interested in REAP participation can work with the dedicated REAP customer call center. The representatives in the call center are responsible for scheduling home energy surveys directly with the customers. Prior to the date of the scheduled survey, customers receive an email notification and pre-survey communications to highlight the key characteristics of the home.

Upon REAP program enrollment, the implementation contractor conducts a comprehensive home energy survey, performs health and safety tests, installs energy efficiency measures, and has a kitchen table talk with the customer. The kitchen table talk allows the customer to speak one on one with a program representative about energy savings behaviors and their monthly electric bills. The implementation contractor also provides the customer a folder that contains information about other PSEG Long Island programs, neighboring utility assistance programs, and PSEG Long Island brochures that contain information aiming to increase energy education and awareness on managing energy usage.

In 2020 and 2021, in response to the pandemic, the REAP program pivoted traditional in-person participation methods to virtual. Customers were offered remote energy surveys and a curbside delivery option for direct install measures. In 2022, remote energy surveys were still offered to customers who feel more comfortable participating virtually. In 2023, the REAP program will continue to offer remote energy surveys.

The REAP implementation contractor is responsible for:

- Hiring local staff to perform home energy surveys and direct measure installation
- Engaging with customers to schedule home energy survey appointments
- Providing customer service and support
- Tracking program performance, including customer participation as well as quality assurance/quality control (QA/QC)
- Reporting monthly on progress toward program goals

PSEG Long Island and the implementation contractor work together to market REAP using the following approaches:

- Utilizing bill inserts to raise awareness of the REAP program
- Delivering targeted direct mail pieces to further inform the customer of program benefits, home energy survey, and call center information
- Calling and door to door canvassing for potential REAP participants
    - Participant is provided opportunity to schedule survey over the phone or in-person during site visit
- Emailing program information to eligible customers
- Hosting open houses at community central locations, like Town Hall offices

To increase referrals and productivity, Program management coordinates with different populations:

- Nonprofit, non-governmental organizations
- Government
- Senior citizens

- Financial/debt counseling organizations
- Faith-based institutions
- Apartment and multifamily dwellings
- Public libraries

Energy Education

A fundamental precept of the REAP program design is extensive customer energy education and support throughout the customer's energy efficiency journey. Education and support for the customer are critical to ensure the customer uses the installed energy efficiency measures appropriately. This is achieved by creating a partnership between the REAP program and the customer. The partnership allows the REAP team member to work with their new partner in identifying energy savings behaviors that will lead to lower monthly electric bills and maximize the benefits of the newly installed energy efficiency measures. Once the energy savings behaviors are identified, they become the partners' Action Commitments and the partner agrees to implement the identified behaviors. Some examples of the energy savings behaviors are lowering the water heater temperature, checking furnace filters, turning off lamps, and utilizing energy saving settings on clothes washers and other appliances.

The partnership concept puts the customer in charge of their energy savings and their experience. Customers who participate in REAP, should agree to become partners, and accept their responsibility through the Action Commitments. The Action Commitments, once agreed on, are included in a formal written agreement, and signed by the new partner and a REAP representative.

Other key focuses of energy education include:

- Use and value of installed high efficiency lighting retrofits
- Set-back thermostat operation and management
- Appliance use and management
- Water conservation measures
- Water heater temperature setting

Referrals

During a home energy survey, the field technician provides the customer, either verbally or tangibly, information about other appropriate energy efficiency programs and assistance programs implemented by PSEG Long Island or other organizations, per PSEG Long Island approval. This is known as a referral. Providing the customer with information about other programs allows them to explore participation in other programs that will benefit them. The field technician is educated on the other programs to assist the customer.

Some of the assistance programs are:

- PSEG Long Island Home Performance Program
- New York State Home Energy Assistance Program
- New York State Weatherization Assistance Program
- Other relevant programs including town- or county-specific programs and social support programs to meet special needs

The field technician also leaves behind a REAP customer folder that includes informative PSEG Long Island brochures and information such as the Energy Saving Guide, "PSEG Long Island 66 Ways to Save On Your Electric Bill, "Household Assistance Rate," and "Financial Assistance."

Lead Generation

PSEG Long Island participates in a multitude of residential events throughout the year to distribute brochures that promote the benefits of the REAP program.

Energy Forum for Advocates

PSEG Long Island hosts an annual Energy Forum for Advocates, which is organized and hosted by the REAP program manager. The Energy Forum provides a platform for advocates to learn about services that can positively impact the lives of the income eligible families they work with. The REAP program manager invites a number of speakers from different assistance programs to speak to the advocates and answer any questions the advocate may have.

Speakers invited to the Energy Forum represent assistance programs including, but not limited to:

- PSEG Long Island's Household Assistance Rate
- Consumer Advocates from PSEG Long Island
- CDC Long Island's Weatherization Assistance Program
- National Grid Home Energy Affordability (HEAT) Program and Energy Affordability Program (EAP)
- Home Energy Assistance Program (HEAP)
- United Way of Long Island's Project Warmth
- DSS Emergency Energy Assistance

The Energy Forum is typically held in the fall prior to the heating season. This ensures the advocates are receiving the latest information on programs that help with heating for their clients. In 2021, the Energy Forum was held virtually and boasted over 100 attendees.

A.2.3.3 *Target Market*

The program is offered to all residential customers who:

- Have a PSEG Long Island account
- Own or rent in the service territory
- Have not participated in REAP in the previous 10 years
- Comply with income guidelines and size of household and meet the qualifying criteria below. Income guidelines are updated in the March-April timeframe

Table A- 11. 2022-2023 REAP Income Guidelines

Size of Family	Maximum Gross Monthly Income	Maximum Gross Annual Income
1	$3,639	$43,664
2	$4,759	$57,104
3	$5,879	$70,544
4	$6,999	$83,984
5	$8,117	$97,408
6	$9,237	$110,848
7	$9,448	$113,376
8	$9,657	$115,888
9	$10,633	$127,600
10	$11,616	$139,387

*Based on 80% of State Median Income

Customer Qualification

Verification of REAP program income eligibility for each PSEG Long Island customer is initially performed by the TRC's customer call center during the initial intake call. The customer must provide proof of income documentation prior to the start of the home energy survey. REAP eligibility is based on number of persons living in the home, total household income, and the inclusion of income from alternate sources.

The implementation contractor's field technician is responsible for the review of customer documentation to ensure eligibility for participation. In addition, the field technician is responsible for the recording of household member's name, annual income, source(s) of income and verification code of documents (VCD) code on the participation agreement form.

Historically, REAP income eligibility was based on 80% of the Median Area Income, as established by the U.S. Department of Housing and Urban Development. Beginning in 2023, to align with the Home Comfort and Home Performance with ENERGY STAR programs, income eligibility will be based on 80% of the State Median Income. This new structure will enable the REAP Program to provide pre-qualified leads for both the Home Comfort and Home Performance with ENERGY STAR Programs, and ultimately provide the income eligible population with a multitude of energy efficiency benefits.

Verification Codes for Documents

- CSO – Child Support/Court Order
- DPW – Department of Public Welfare
- EVL – Employer Verification Letter
- PS2 – Pay Stubs, previous two months
- SSD – Social Security Disability
- SSI – Supplemental Security Income Award Letter
- SSR – Social Security Retirement
- SSS – Social Security Survivor's Benefit
- UAL – Unemployment Award Letter
- VBA – Veteran's Benefits Award Letter
- W-2 – Previous Year W-2 or 1040 SSE Form
- WCA – Workman's Compensation Award Letter

- Other ______________________________

A.2.3.4 *Measures and Incentives*

The REAP program offers the following measures:

Table A- 12. Residential Energy Affordability Partnerships Program: List of Measures

Measure	2023 Planned Units	Measure Incentives	Measure Rebates
16 cf Refrigerator	60	-	-
18 cf Refrigerator	60	-	-
21 cf Refrigerator	60	-	-
Advanced Power Strips (Tier II)	2,000	-	-
Dehumidifiers 25-50 Pints/Day	130	-	-
Dehumidifiers >50 Pints/Day	170	-	-
ES Room Air Purifiers (<200 CADR)	150	-	-
ES Room Air Purifiers (>200 CADR)	100	-	-
Water Temperature Turndown/HH	60	-	-
Faucet Aerators/unit	320	-	-
Low Flow Showerheads/unit	200	-	-
Thermostatic Valve	200	-	-
10,000 Btu RAC 1 Unit/HH	60	-	-
12,000 Btu RAC 1 Unit/HH	60	-	-
6,000 Btu RAC 1 Unit/HH	450	-	-
8,000 Btu RAC 1 Unit/HH	200	-	-
Pipe Insulation/ln ft	300	-	-
Nightlight	1,800	-	-
LED Bulbs	20,000	-	-
Smart Thermostats – Learning – Direct Install	1,000	-	-

It is estimated that 2,000 REAP visits will be conducted in the 2023 program year. The numbers of visits per year is expected to remain constant through the 2025 program year. A variety of the above-mentioned energy saving measures will be installed during the visit.

Offered measures are divided into core measures and major efficiency measures.

- **Core Measures:** Measures that are typically directly installed regardless of the space heating fuel used by the PSEG Long Island residential customer.
- **Major Efficiency Measures:** Those measures that will cost-effectively reduce the energy consumption of high-use or seasonal appliances but typically require more extensive treatment. All energy-efficient measures are installed at no cost to the customer or building owner, if cost-effective, given site specifics. In the case of partners who occupy rental property, core efficiency measures involving building owner property, such as non-tenant-owned appliances, may not be installed without the prior written approval of the building owner.

Table A- 13. Core and Major Efficiency Measures Offered through REAP

Typical Core Measures	Major Efficiency Measures
• Installation of high-efficiency lighting • Pipe Insulation* • High-efficiency showerheads* • Faucet Aerators* • Reducing electric water heater temperature settings* • Thermostatic Shower Valves* • Smart Strips • Smart Thermostats	• Replacement of inefficient room air conditioners (RACs), dehumidifiers, room air purifiers • Replacement of inefficient refrigerators

* Pipe insulation, low flow shower heads, faucet aerators, water temp turndown and thermostatic shower valve are provided to customers with electric domestic hot water heaters only.

At the completion of a REAP home energy survey, follow up work may be identified in which the customer can utilize income eligible enhanced incentives through the Home Comfort and Home Performance with ENERGY STAR program.

A.2.3.5 *Outreach*

The REAP program reaches customers and advocates in a variety of ways. The program coordinator and/or program manager communicates directly with PSEG Long Island customers, homeowners, and renters, and indirectly through related social agencies.

In the 2021 calendar year, the REAP team attended over 30 events at central community locations, such as libraries, churches, fairs. At these events, the REAP program coordinator and/or program manager conducted presentations, distributed program information, and made connections with customers and advocates.

The REAP program also focuses on building relationships with other organizations that can serve REAP-eligible customers. The goal is to not only collaborate with other organizations but to build even larger referral potentials and relationships with community liaisons, community councils and board members, housing authorities, departments of social services, and other government organizations that serve income eligible and senior citizen communities. To build these relationships, the REAP program provides workshops and presentations for agency staff meetings, support/consumer groups, and large-scale community events.

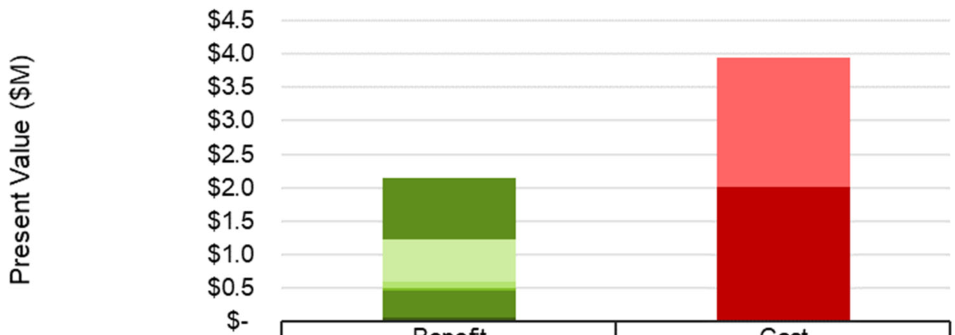
Customers can also reach the REAP program directly through the PSEG Long Island website or through E-blasts that are sent out periodically. Both avenues refer the customer to a REAP mini-application that is sent directly to the REAP team once completed. The E-blast response to the mini-app has resulted in a 24% scheduling rate.

Other forms of outreach used by the REAP team are monthly post-card mailings targeting income eligible areas, door hangers, and brochures delivered to foodbanks. In 2023-2025, these effective and engaging outreach strategies will continue to be implemented.

A.2.3.6 *Business Case*

REAP has a SCT benefit-to-cost ratio of 0.37 and RIM benefit-to-cost ratio of 0.12. A list of the value streams considered in the BCA is detailed in Figure A-3.

Figure A-3. Present Value Benefits and Costs of SCT – REAP



	Benefit	Cost
Fuel Switching Benefits	0.92	-
Net Avoided SO2 and NOx	0.000009	-
Net Avoided CO2	0.63	-
Avoided Distribution Capacity Infrastructure	0.10	-
Avoided Transmission Capacity Infrastructure	0.04	-
Avoided Energy (LBMP)	0.41	-
Avoided Generation Capacity Cost (AGCC)	0.05	-
Participant DER Cost	-	1.94
Program Administration Costs	-	2.01
Total	2.15	3.95

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	0.92	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.00	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	0.63	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.10	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.04	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	0.41	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.05	
8	**Participant Distributed Energy Resources (DER) Cost**	Includes cost of incremental equipment and installation.		1.94
9	**Program Administration Costs**	Includes labor, evaluation, and advertising costs.		2.01
	Total Benefits		**2.15**	
	Total Costs			**3.95**
	SCT Ratio		**0.54**	

NPV = Net present value
LBMP = Location-based marginal pricing

A.2.4 Home Performance with ENERGY STAR

The primary objective of the Home Performance with ENERGY STAR program is to support residential customers in making high efficiency choices when considering updates to their homes envelope and heating systems. This is achieved through utilizing a comprehensive whole house approach that identifies areas for improved efficiency, safety, and comfort of the home. Newly installed weatherization measures and heating equipment operate in a customer's home for 10 to 25 years. It is paramount to reach customers and influence their choices to ensure their decisions are energy efficient. This objective aligns with the overall goal of reducing the carbon footprint of customers who utilize electric, oil, or propane as their primary heating source. Income eligible customers who heat their homes with natural gas and utilize Central Air Conditioning systems to service 50% or more of their cooling load are also eligible for weatherization rebates through the Home Performance with ENERGY STAR program. All other natural gas heating customers are referred to National Grid's weatherization program. This became effective in 2022 in response to the MOU signed between National Grid and PSEG Long Island.

The HPwES program provides a participation pathway for all customers by offering whole house solutions to income eligible and market-rate customers. Enhanced rebates are available for income eligible customers for whole-house heat pumps and weatherization measures. PSEG Long Island works with Energy Finance Solutions (EFS) to qualify income eligible customers. Beginning in the 2023 program year, income eligible customers will be qualified utilizing 80% of the State Median Income. Historically, income eligibility was based on 60% of the State Median Income. To impact more income eligible customers, and promote whole-house solutions, expanding the income eligibility guidelines is necessary. Income verification documents like letters from the Home Energy Assistance Program (HEAP) or Social Security will continue to be accepted. Participating HPwES partners may also offer low-interest on-bill recovery loans and smart energy loans for qualified market rate and income eligible customers.

The US Department of Energy (DOE) administers the Home Performance with ENERGY STAR (HPwES) Program and works in conjunction with the US Environmental Protection Agency (EPA) to support local program sponsors. PSEG Long Island administers the HPwES Program on behalf of the sponsor, LIPA. TRC administers the program and provides support to PSEG Long Island, HPwES partners (trained and vetted contractors), and customers. TRC provides design and implementation strategies through innovative program design and management, quality assurance and quality control, technical training for

HPwES partners, and HPwES partner support to ensure the promotion of quality installation of energy efficient measures.

The HPwES program has built a robust partner network. The program has built strong working business partnerships with the existing PSEG Long Island HPwES contractor base, as well as various trade allies and constituent-based organizations like NYSERDA, Long Island Green Homes, BPI, BPCA, and Efficiency First.

Program Leads

1. **PSEG Long Island Home Energy Assessments:** PSEG Long Island Home Energy Assessments (HEA) are free energy audits available to eligible single-family homeowners in the PSEG Long Island service territory. Customers who are interested in receiving a free HEA complete a Home Energy Assessment Online Application, found on the PSEG Long Island website. The customer answers questions about their home, like heating and cooling equipment type and the age of the home and selects a qualified contractor to conduct the HEA. The selected contractor is notified of the HEA, through the Lead Partner Portal, and promptly schedules the audit with the customer. During the HEA, the contractor conducts a comprehensive audit of the home, utilizing a PSEG Long Island branded audit tool built by TRC, and educates the homeowner on the different energy savings opportunities offered by PSEG Long Island, ranging from duct sealing to air source heat pumps. At the conclusion of the HEA the customer will receive a PDF of the completed audit and recommendations. The PDF is also stored in the Captures database. Please note, although not all natural gas customers qualify for the PSEG Long Island HPwES rebates, all natural gas customers are still eligible to receive a free Home Energy Assessment.
2. **Home Performance Direct Install:** The Home Performance Direct Install (HPDI) program is a free program available to eligible PSEG Long Island electric heat residential customers. The HPDI program includes a free Home Energy Assessment, the direct installation of free energy efficiency measures like LED bulbs, smart strips, and low flow domestic hot water devices. Customers who participate in the HPDI program can also participate in HPwES and are informed of the HPwES offerings.

A.2.4.1 *Notable Changes*

In 2023, the HPwES rebate offerings continue to be available through the Home Comfort/Home Performance application. The Home Comfort/Home Performance application provides customers with holistic whole-house solutions through the promotion, and rebate, of cold climate air source heat pumps, HPwES weatherization measures, integrated controls, smart thermostats, electric hot water heating equipment, and Tune-Ups. Electric hot water heating equipment (ENERGY STAR Heat Pump Water Heaters and Electric Tankless Water Heaters) has typically been offered through the EEP program but including it in the program offering allows the HPwES partner and participant to consider going all-electric to meet their space heating and water heating needs through one central application.

In 2022, and continuing in the 2023 program year, natural gas customers who are income eligible and heat their homes with natural gas and utilize Central Air Conditioning systems to service 50% or more of their cooling load are eligible for weatherization rebates through the Home Performance with ENERGY STAR program. All other natural gas heating customers are referred to National Grid's weatherization program. This became effective in 2022 pursuant to an MOU between National Grid and PSEG Long Island.

The HPwES program offering for market-rate customers was increased from $1,000 per project to $1,050 per project, beginning in 2023, to engage more market-rate customers and contractors and assist with out-of-pocket expenses.

The HPwES program's income eligible offering continues to be available in 2023. Historically, the income eligible offering was $4,000 per project where duct sealing, insulation, and air sealing were installed. In 2023, the income eligible offering has been expanded to reflect $6,000 per project. To increase accessibility and participation in the income eligible community, it was determined an increase in the offering would allow the program to impact more customers and provide the pathway to that holistic, whole-house solution. A whole-house solution begins with proper weatherization of the home. The enhanced rebates make this achievable. Income eligible customers may also participate in the Home Comfort Heat Pump offering and receive $5,500/Ton for whole house cold climate ASHP solutions and $1,500 per ENERGY STAR Heat Pump Water Heater. The enhanced rebates also achieve another PSEG Long Island objective; providing the income eligible customer with enough support through rebates to ensure the customer has little to no out of pocket costs, realize significant energy savings, and overall monthly bill savings.

To further impact the income eligible community, the income eligibility guidelines also became more generous. Historically, income eligibility was based on 60% of the State Median Income. Beginning in 2023, income eligibility will be based on 80% of the State Median Income to ensure more income eligible customers are aware of the offerings and can receive the multitude of benefits through program participation. Utilizing 80% of the State Median Income, aligns closer with the cost-of-living expenses on Long Island, as opposed to the 60% State Median Income. The financial landscape on Long Island is much different than the rest of New York State and the income eligibility guidelines should reflect that. Based on data sourced from the 2019 Census ACS[39] , the "Real Median Household Income" for Nassau County was $118,453 and $106,228 for Suffolk County. The "Real Median Household Income" For New York State was $72,108 and $65,712 for the United States.

Also new for 2023, participants who complete projects containing both whole house air source heat pumps and weatherization will be eligible for a participation bonus. Income eligible and market rate customers can receive an additional $500 for these projects. The addition of the participation bonus should influence the customer to explore the benefits associated with completing weatherization and installing a whole house air source heat pump as one project. The bonus should also assist in reducing the financial burden on the participant.

As discussed in the Home Comfort section, PSEG Long Island plans to explore increasing the adoption of home energy retrofits and residential heat pumps in the single-family residential sector through a partnership with a company that can help customers finance key home improvements using the money homeowners currently spend on wasted energy. PSEG Long Island will continue to offer smart energy loans and On-Bill Financing options for weatherization, heat pumps, and geothermal projects.

In April 2021, PSEG Long Island launched a partnership with Sealed, a New York-based company that finances key home improvements using the money homeowners currently waste on energy. The goal of the partnership is to increase the adoption of home energy retrofits and potentially residential heat pumps in the single-family residential sector by allowing for those customers to pay for energy-saving home improvements with the value of their expected energy savings. Sealed invests in home improvements that save energy and customers pay back based on the actual energy that is saved. If customers don't save energy, Sealed does not get paid back. This partnership is market-based relationship and does not require any dedicated program budget from PSEG Long Island. Sealed provides all the necessary capital

[39] https://www.deptofnumbers.com/income/new-york/nassau-county/

for customer acquisition, operations, and project finance. In addition, Sealed provides upfront education and engagement on comfort and other non-energy customer pain points, and provides customers with a proposal and/or recommendations on how they can solve these problems. Customers will receive this education and engagement over phone and web and will be connected to local contractors once they have determined the project that will best meet their needs.

A.2.4.2 *Program Delivery*

PSEG Long Island's HPwES program provides customer rebates and contractor incentives for the installation of weatherization measures and building shell upgrades like insulation, air sealing, and duct sealing. Customers and HPwES partners must meet the minimum efficiency requirements for each measure installed to qualify for the rebates and incentives.

All HPwES projects are reviewed for quality control and accuracy. In 2022, all projects required pre-approval. This practice will continue in the 2023 program year.

A significant amount of the HPwES program participation is driven by the partnership between the HPwES program and HPwES partners. Prospective HPwES contractors must submit a signed PSEG Long Island HPwES Contractor Participation Agreement and provide documentation showing proof of business identification, financial condition, insurance, licensing, satisfactory customer relationships, and Building Performance Institute (BPI) Gold Star Status. On approval, the contractor is deemed a Provisional Participating Contractor until they successfully complete five HPwES projects. As of April 2022, 16 participating HPwES partners were enrolled in the program. On a monthly basis all electric (kW and kWh) savings are reported to PSEG Long Island. Fossil fuel (oil/propane, other non-natural gas heating fuels) savings are converted to MMBtu and reported to PSEG Long Island; PSEG Long Island reports the necessary savings metrics to LIPA and NYSERDA.

A.2.4.3 *Target Market*

The Home Performance Home Energy Assessment (HEA) is available to all eligible PSEG Long Island single-family home residential customers. Based on historical data collected from the Home Energy Assessment Tool and Online Application, 7% of customers utilize electric heat, 39% of customers utilize natural gas heat, 51% of customers utilize oil heat, and 3% of customers utilize propane heat. The Home Performance Direct Install program is available to eligible residential customers with electric heat.

Home Performance with ENERGY STAR rebates are available to all customers, except those who heat their homes primarily with gas and do not have a central air conditioning system. Enhanced rebates are available for customers who qualify as income eligible. The HPwES program utilizes 80% of the State Median Income to qualify homeowners is income eligible. Loans are available from EFS for both market and income eligible projects.

It is estimated that 4,000 HEAs, 100 Home Performance Direct Installs, and 1,400 Home Performance with ENERGY STAR projects will be completed in the 2023 program year.

PSEG Long Island intends to offer the 2023 program in keeping with prior years, with the exception of the program modifications made in 2022 to support the partnership with National Grid.

A.2.4.4 *Measures and Incentives*

The list of measures that are offered in the Home Performance with ENERGY STAR program are included in the following tables.

Table A- 14. PSEG Long Island Home Performance with ENERGY STAR-Eligible Measures List

Eligible Measure		Minimum Efficiency Requirements
Duct Sealing		UL 181B mastic or tape; use of duct tape is disallowed
Duct Insulation		Installed in accordance with all applicable state and local codes
Building Shell	Insulation (attic, wall, floor, band joist, basement, crawl space)	Must be accompanied by blower door assisted air sealing per BPI standards
	Air Sealing	Blower door assisted per BPI standards

Table A- 15.Home Performance with ENERGY STAR: List of Measures

Measure	2023 Planned Units	Measure Incentives	Measure Rebates
DI - Smart Strips – Tier II (75% of projects)	83	-	-
DI - Water Temperature Turndown/HH (25% of projects)	127	-	-
DI - Faucet Aerators/unit (25% of projects)	19	-	-
DI - Low Flow Showerheads/unit (25% of projects)	4	-	-
DI - Thermostatic Valve (25% of projects)	31	-	-
DI - LED Bulbs (100% of projects; 8/HH)	773	-	-
DI - Nightlight (75% of projects)	163	-	-
HEA Audit Giveaway (A19 LEDs)	8,000	-	$5
HEA Audit Giveaway (Smart Strip Tier I)	2,000	-	$31
HEA Audits	4,000	-	-
LMI Projects	900	-	$6,000
Market Projects – Non-Gas Customers	360	-	$1,050
Market Projects – Gas Customers	140	-	$150

A.2.4.5 *Outreach*

The Home Performance program focuses on promoting the free Home Energy Assessment component of the Program. Home Energy Assessments are available to all eligible PSEG Long Island single-family home residential customers. The Home Energy Assessment (HEA) provides the customer with a comprehensive whole-house energy review including, but not limited to, weatherization measures, heating and cooling systems, appliances, domestic hot water. The Home Energy Assessment is promoted at PSEG Long Island sponsored events, such as home shows and street fairs, direct mailings, the PSEG Long Island website, and by the HPwES partners.

The HEA is a critical outreach effort, as the HPwES partner has the opportunity to engage directly with the customer about the benefits of participation in the HPwES program. The results of the HEA identify where the customer can make improvements in the home through the HPwES program.

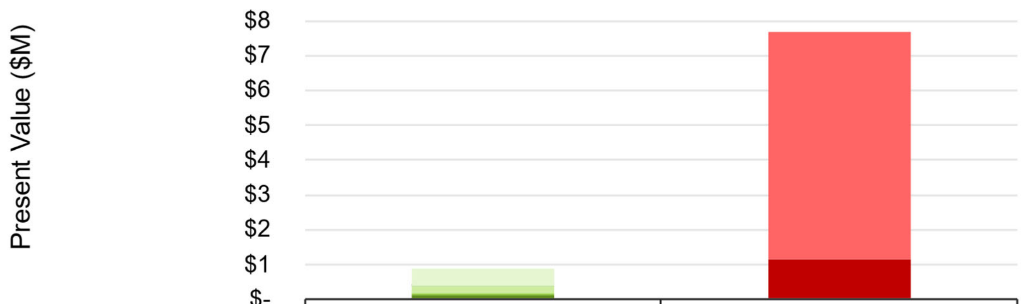
The Home Performance Direct Install Program (HPDI) is promoted through quarterly postcard mailings to single family homes with electric heat rate codes. The Home Performance team has also engaged directly with communities, like communities with electric heat, and conducted informative program presentations.

Beginning in 2020, to maintain contractor engagement during the pandemic, the HPwES team, along with the Home Comfort team, started offering contractors virtual training sessions. The sessions focused on topics like financing, application submittals, technology deep dives, and general program updates. Contractors were also invited to speak directly with TRC subject matter experts during Friday morning Virtual Open House meetings. These virtual engagement methods were still conducted in the 2022 program year and will continue through 2023 as necessary.

A.2.4.6 *Business Case*

Home Performance with ENERGY STAR has a SCT benefit-to-cost ratio of 0.15 and RIM benefit-to-cost ratio of 0.05. A list of the value streams considered in the BCA is detailed in Figure A-4.

Figure A-4. Present Value Benefits and Costs of SCT – HPwES



	Benefit	Cost
Fuel Switching Benefits	0.50	-
Net Avoided SO2 and NOx	0.000006	-
Net Avoided CO2	0.19	-
Avoided Distribution Capacity Infrastructure	0.05	-
Avoided Transmission Capacity Infrastructure	0.02	-
Avoided Energy (LBMP)	0.11	-
Avoided Generation Capacity Cost (AGCC)	0.03	-
Participant DER Cost	-	6.53
Program Administration Costs	-	1.14
Total	0.91	7.67

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	0.50	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000006	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	0.19	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.05	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.02	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	0.11	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.03	
8	**Participant Distributed Energy Resources (DER) Cost**	Includes cost of incremental equipment and installation.		6.53
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		1.14
	Total Benefits		**0.91**	
	Total Costs			**7.67**
	SCT Ratio		**0.12**	

NPV = Net present value
LBMP = Location-based marginal pricing

A.2.5 All Electric Homes Program

The All Electric Homes program was launched in April 2021 to support residential customers and residential developers who want to build or retrofit a single-family home as "All Electric". To be eligible for the All Electric Homes program, customers must install electric-end use equipment in a New Construction residence or convert all existing fossil fuel equipment in an existing residence. Customers who wish to convert their existing propane, oil, or natural gas equipment are eligible. A backup fossil fuel connection is not permissible for New Construction. All existing fossil fuel connections, in existing residences, must be disconnected. Although a fossil-fuel connection is not permissible on site, a connection for a backup generator is allowable in the event of a power-outage.[40] This exception is implemented as an optional safety and resiliency measure in order to ease participation for customers with existing generators and to reassure customers that they can have a backup in the event of a power outage. This is consistent with our Whole House Heat Pump offering, which still allows fossil fuel secondary heating for the coldest days of the year.

The All Electric Homes program offers two pathways to participation. The "Tier I" pathway includes cold climate air source heat pumps, tankless water heaters, and ENERGY STAR labeled appliances. The "Tier II" pathway includes cold climate air source heat pumps, heat pump water heaters, and ENERGY STAR Most Efficient labeled appliances. All participants who participate in the Tier I offering will receive a 10% bonus on all required rebated measures. All participants who participate in the Tier II offering will receive a 25% bonus on all required rebated measures. The participation bonuses are intended to offset the costs

[40] The fossil fuel source can hold be connected to the generator or, if the customer has one, a gas stove.

associated with ENERGY STAR and ENERGY STAR Most Efficient appliances, as well as the costs associated with electric cooking equipment. In 2022, the electric cooking equipment requirement was waived in order to engage with more customers. Participating All Electric Homes customers may install either electric cooking equipment or propane cooking equipment. Similar to 2021 and 2022, the cooking equipment will not be rebated, nor will savings be claimed. Additionally in 2022, to stimulate the market, a $2,000 per project contractor incentive was introduced.

The All Electric Homes application contains required and optional measures, such as Cold Climate Air Source Heat Pumps, Geothermal Heat Pumps, Water Heating, Electric Appliances, Weatherization measures, and other equipment like Heat Pump Pool Heaters. The measures included in the All Electric Homes application were previously screened for program offerings like Home Comfort, Home Performance with ENERGY STAR, and the EEP Program.

All measures found in the All Electric Homes application are not required for participation, however a base set of measures must be installed in order to qualify for All Electric Homes rebates and receive participation bonuses. The intent of including non-required measures in the application is to provide the customer a one-stop “all electric” shop for their project. Including all appropriate measures in the application also promotes a holistic whole house solution for the participant. Throughout the application, there are indicators informing the customer which measures are required and which measures are optional.

The following measures are required to be eligible for the All Electric Homes Program:

Table A- 16. Required Measures for All Electric Homes Program Eligibility

All Electric Homes – Tier I	All Electric Homes – Tier II
Cold Climate Air Source Heat Pump*	Cold Climate Air Source Heat Pump*
Smart Thermostat*	Smart Thermostat*
Tankless Water Heater*	Heat Pump Water Heater*
ENERGY STAR Electric Dryer*	Most Efficient Heat Pump Dryer*
ENERGY STAR Clothes Washer	Most Efficient Clothes Washer*
ENERGY STAR Dishwasher	Most Efficient Dishwasher
ENERGY STAR Refrigerator	Most Efficient Refrigerator
ENERGY STAR LED Lighting	ENERGY STAR LED Lighting
Standard Electric/Propane Cooking Range	Most Efficient Induction/Propane Cooktop/Oven

*Indicates a rebate is available

The following measures are optional for the All Electric Homes Program:

Table A- 17. Optional Measures for All Electric Homes Program Eligibility

Geothermal Ground Source Heat Pump**	ENERGY STAR Dehumidifier
Heat Pump Pool Heater	ENERGY STAR Room Air Purifier
	Weatherization

** Customers can elect to install a Geothermal Ground Source Heat Pump in place of a Cold Climate Air Source Heat Pump and still qualify for the All Electric Homes Program and bonuses

The All Electric Homes program collaborates with developers and PSEG Long Island Lead Partners to promote the All Electric Home offering to the public.

The promotion of the All Electric Homes program will continue in 2023-2025.

A.2.5.1 *Notable Changes*

In Mid-2022, the All Electric Homes program launched two significant changes. To alleviate customer concerns related to preferred cooking equipment, the program added an option for Propane Cooking. This allowance is commensurate with the SMUD All-Electric Homes Program, which permits mixed-fuel homes to participate under certain circumstances. To stimulate the market and engage Partners and developers, a per project contractor incentive was introduced. Eligible contractors can receive a $2,000 participation bonus for completing an All-Electric New Construction project or an Existing Building conversion project.

The inclusion of propane cooking equipment and the $2,000 per project contractor incentive will remain a part of the offering in 2023.

In 2023, to remain consistent with the Energy Efficient Products program, the battery-operated lawn care equipment will be removed from the All Electric Homes program.

A.2.5.2 *Program Delivery*

The All Electric Homes participation will primarily be driven through partnerships with developers and existing relationships with Home Comfort Partners, Home Performance Partners, and Multi-Family Partners and Developers. Leveraging relationships with existing partners and developers, and also promoting the program at industry events will result in creating program awareness and participation.

All partners who will participate in this offering have already been trained and vetted by the PSEG Long Island program. This ensures customers will have a positive “All Electric” participation experience.

TRC also holds weekly open-house meetings for all participating Lead Partners. Interested Lead Partners and developers will have the opportunity to speak one-on-one with a member of the Residential team to learn more about the program and navigate the application.

A.2.5.3 *Target Market*

The program is offered to all residential customers in the PSEG Long Island service territory. All qualified Residential developers with eligible projects and previously vetted lead partners may also participate.

A.2.5.4 *Measures and Incentives*

The measures available in the All Electric Homes program include equipment found in the current Home Comfort program, Home Performance with ENERGY STAR program (HPwES), and the EEP program. The incentives for the All Electric Homes program are consistent with the rebates offered through Home Comfort, HPwES, and EEP.

Customers are eligible for a Tier I or Tier II participation bonus. Contractors are eligible for a $2,000 per project contractor incentive.

The full list of required and optional measures for the All Electric Homes Program are listed in Table A-14 and Table A-15.

A.2.5.5 *Outreach*

The All Electric Homes program outreach strategy, aside from developer/lead partner/customer word of mouth, includes a variety of public platforms:

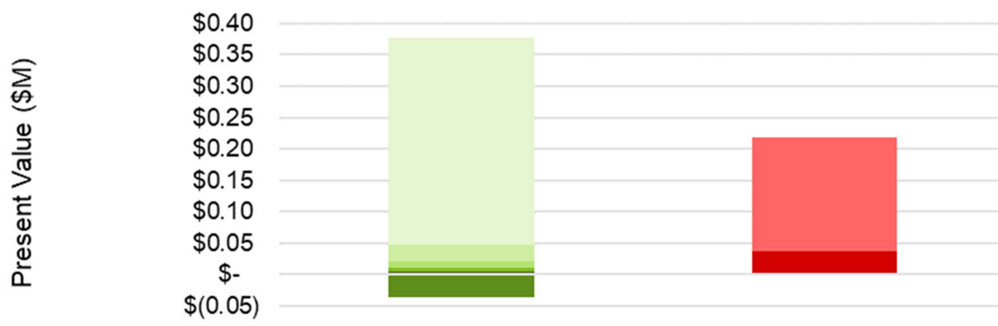
- PSEG Long Island Website page
- Industry networking events and speaking engagements, such as HIA, LIBI, and the United States Green Building Council

In 2023-2025, the Residential team will continue to implement the above listed outreach strategies and work with participating developers and lead partners on tools to promote the installation all electric equipment. In addition, the Residential team will develop educational material to provide developers, lead partners, and customers a better understanding of the energy and non-energy benefits associated with an All Electric Home.

A.2.5.6 *Business Case*

The All Electric Homes program has a SCT benefit-to-cost ratio of 1.70 and RIM benefit-to-cost ratio of 2.38. A list of the value streams considered in the BCA is detailed in Figure A-5.

Figure A-5. Present Value Benefits and Costs of All Electric Homes Program



	Benefit	Cost
Fuel Switching Benefits	0.33	-
Net Avoided SO2 and NOx	0.000004	-
Net Avoided CO2	0.02	-
Avoided Distribution Capacity Infrastructure	0.01	-
Avoided Transmission Capacity Infrastructure	0.0048	-
Avoided Energy (LBMP)	(0.04)	-
Avoided Generation Capacity Cost (AGCC)	0.01	-
Participant DER Cost	-	0.18
Program Administration Costs	-	0.04
Total	0.34	0.22

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	0.33	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000004	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	0.02	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.01	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.0048	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	(0.04)	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.01	
8	**Participant Distributed Energy Resources (DER) Cost**	Includes cost of incremental equipment and installation.		0.18
9	**Program Administration Costs**	Includes contractors fee, labor, and evaluation costs.		0.04
	Total Benefits		**0.34**	
	Total Costs			**0.22**
	SCT Ratio		**1.56**	

NPV = Net present value
LBMP = Location-based marginal pricing

A.2.6 Multifamily Program

The Multifamily program was launched in October 2020. The intent of the Multifamily program is to assist New Construction and Existing Building Multifamily Developers and Building Owners in constructing and retrofitting Multifamily buildings to be energy efficient.

At launch, the Multifamily program targeted New Construction Multifamily developments. In 2021, the Multifamily Program expanded to include Existing Building Multifamily properties. All eligible properties must consist of five or more units. High-Rise and Low-Rise buildings both qualify. High-Rise buildings are considered buildings with four or more floors. Low-Rise buildings are considered buildings with three or less floors.

The Multifamily program offers rebates for Common Area Lighting (Indoor and Outdoor), Common Area Heating and Cooling, Common Area Pool Equipment, Common Area VFDs, In-Unit Heating and Cooling, and In-Unit Appliances. The measures included in the Multifamily application were previously screened for other programs like Fast Track Lighting (Common Area Lighting), Commercial HVAC (Common Area Lighting), Home Comfort (In-unit HVAC) and were rescreened as necessary to align with Multifamily specific factors, like operating hours. Rebate levels remained constant between the original program offerings and the Multifamily offering.

The Multifamily program is the only EEBEDR program that contains both Commercial (Common Area) measures and Residential (In-Unit) measures in one application. The intent of including both Commercial and Residential measures in one application is to provide developers and building owners a "one-stop shop" program experience without the burden of completing multiple equipment applications for one project.

A.2.6.1 *Notable Changes*

In 2021, the Multifamily program offering expanded to include Existing Building scenarios. In 2022, ENERGY STAR rebates were included for Clothes Washer, and for the bundling of ENERGY STAR measures. The measures are required to be "bundled" to ensure cost effectiveness. Eligible measures for the bunding approach include ENERGY STAR Clothes Washers, ENERGY STAR Refrigerators, and ENERGY STAR Dishwashers. Elevator Modernization was also added to the offering. These offerings will continue to be available in 2023.

A.2.6.2 *Program Delivery*

The Multifamily program participation is driven through partnerships with developers and industry associations. Developer relationships are an integral part of the growing Multifamily program.

TRC also holds weekly open-house meetings for all participant Lead Partners and Developers. Interested Lead Partners and Developers have the opportunity to speak one-on-one with a member of the Commercial or Residential team to learn more about the program and navigate the application.

A.2.6.3 *Target Market*

The Multifamily program is offered to developers and building owners who install efficient equipment in low-rise or high-rise multi-family buildings consisting of five or more units.

A.2.6.4 *Measures and Incentives*

The Multifamily program offers rebates for measures found in the following programs:

- Residential Home Comfort Program
  - Partial and Whole Unit Air Source Heat Pumps
  - Smart Thermostats and Integrated Controls
- Residential EEP Program
  - ENERGY STAR/Most Efficient Appliances
  - ENERGY START Lamps
  - Water Heating Equipment
  - Advanced Power Strips
  - Smart Thermostats
- Geothermal Program
  - Vertical Stack Heat Pumps
  - Water to Air Heat Pumps
  - Water to Water Heat Pumps
  - DGX
- Commercial HVAC Program

- Commercial Prescriptive Program
  - VFDs
  - Pool Equipment
  - Elevator Modernization
- Commercial Lighting Program
  - Interior Lighting
  - Exterior Lighting

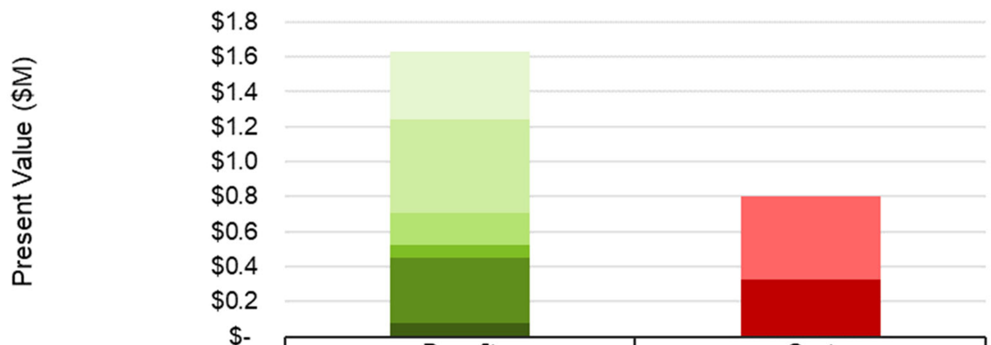
A.2.6.5 *Outreach*

The CEP engages with Multifamily developers and building owners by working with PSEG Long Island Major Account Executives (MAEs) to send out email blasts, and meeting with industry associations like the Building Owners and Management Association (BOMA) and the Long Island Building Institute (LIBI).

A.2.6.6 *Business Case*

The Multifamily program has a SCT benefit-to-cost ratio of 3.09 and RIM benefit-to-cost ratio of 0.20. A list of the value streams considered in the BCA is detailed in Figure A-6.

Figure A-6. Present Value Benefits and Costs of Multifamily Program



	Benefit	Cost
Fuel Switching Benefits	0.39	-
Net Avoided SO2 and NOx	0.000003	-
Net Avoided CO2	0.54	-
Avoided Distribution Capacity Infrastructure	0.18	-
Avoided Transmission Capacity Infrastructure	0.07	-
Avoided Energy (LBMP)	0.37	-
Avoided Generation Capacity Cost (AGCC)	0.08	-
Participant DER Cost	-	0.48
Program Administration Costs	-	0.32
Total	1.63	0.80

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	0.39	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.00	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	0.54	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.18	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.07	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	0.37	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.08	
8	**Participant Distributed Energy Resources (DER) Cost**	Includes cost of incremental equipment and installation.		0.48
9	**Program Administration Costs**	Includes contractors fee, labor, and evaluation costs.		0.32
	Total Benefits		**1.63**	
	Total Costs			**0.80**
	SCT Ratio		**2.03**	

NPV = Net present value
LBMP = Location-based marginal pricing

A.2.7 Commercial Efficiency Program

PSEG Long Island's CEP offers eligible nonresidential customers rebates for a number of energy savings conversation measures and engineering and design services. The rebates are intended to offset installation costs and costs associated with projects that go through the Technical Assistance program.

In 2023, and through program year 2025, PSEG Long Island's CEP proposes providing customer rebates for the following EE measures:

- Lighting
  - Indoor Lighting
    - Performed Based
    - Prescriptive (Fast Track)
  - Outdoor Lighting

- HVAC
  - Performance Based
  - Small-Medium-Business (SMB) Air-Source Heat Pump Whole Building Approach
- Geothermal
- Standard Application
  - Variable Frequency Drives
  - Compressed Air
  - Kitchen Equipment
  - Elevator Modernization
- Refrigeration
- Water Heating and Conservation
- Custom and Custom Retrofit
  - Data Collection forms for Chillers and Data Centers
- Beneficial Electrification
  - Non-Road Electric Vehicles (EVs)
  - Pool Equipment
  - Electric Kitchen Equipment
- Technical Assistance (TA) Program:
  - LEED Certification and Points
  - ENERGY STAR Labeled Buildings
  - Energy Engineering Study
  - Whole Building (Energy Modeling)

The CEP strives to deliver a positive customer experience through the diverse portfolio of measures and rebates. The CEP also provides participating lead partners with equipment training, program education, and other tools to deliver a first-class participation experience for the customer. Similar to previous years, the CEP continues to implement the Prime Efficiency Partner Program. All lead partners who have been certified as Prime Efficiency Partners (PEPs) are vetted, trained, and tested on CEP guidelines and program requirements. All PEPs must re-apply for certification each year.

A.2.7.1 *Notable Changes*

In 2023, the CEP continues to offer the performance based interior lighting program that incentivizes customers and contractors to install the most energy efficient equipment available. In past years, the CEP lighting rebates were more in line with a prescriptive rebate approach and rebated per fixture. The 2023 rebate is based on energy savings. As LED lighting programs begin to phase out between 2023-2025, LED lighting will be rebated using an approach best in line with market conditions.

In 2020, PSEG Long Island's EEDR programs' main goal metric was adjusted from kWh to MMBtu. The adjustment in the program's metric was necessary to better align the portfolio with New York State's GHG reduction goals. Adjusting the metric paved the way for the CEP to develop a fuel agnostic methodology for fuel switching measures like air source heat pumps and variable frequency drives. The adjustment in metric also allowed the CEP to explore other fuel switching, or beneficial electrification, measures. The CEP launched a prescriptive beneficial electrification program to target those necessary MMBtu savings.

Equipment offered under this program component includes battery-operated non-road electric vehicles (golf carts and forklifts), heat pump pool heaters and solar covers, and kitchen equipment.

In 2023-2025, the CEP will continue to incorporate measures and programs that support the MMBtu savings goal.

A.2.7.2 *Program Delivery*

The CEP participation is driven through partnerships with installation contractors, or Lead Partners. Customers may opt to participate as a self-install, but participation is primarily driven through lead partners. The CEP collaborates with lead partners and provides a platform for lead partners to work directly with representatives from the CEP at weekly open-house meetings. The weekly open house meetings allow contractors to talk about program requirements, applications, and to provide feedback on the participant experience. The CEP also offers training sessions on new technologies and new programs. In-person contractor meetings and trainings were suspended in 2020 due to the pandemic, however, the EE Programs pivoted traditional meeting methods to virtual. The CEP continues to utilize the virtual meetings to keep the lead partners engaged and supported.

The weekly contractor meetings have had such a tremendous impact, from the initial launch through today, that AESP's National Conference featured the Contractor Meetings in 2016. Speakers from TRC were invited to discuss the successes of the meetings and were scored among the best at the conference. In 2018 and again in 2020 TRC was invited back to AESP to speak at the Summer Conference. At the 2020 conference, TRC speakers discussed how the EE Programs adapted to the pandemic, decarbonization efforts, and integrated demand-side management. AESP also invited TRC to develop an article for its June 2020 issue of "Strategies Monthly" that highlighted the PSEG Long Island Beneficial Electrification programs and fuel agnostic methodologies.

In addition to the weekly contractor meetings and trainings, TRC hosts several contractor breakfasts, new technology expos, and regularly participates in industry events such as USGBC, ASHRAE, HIA, and AIA. TRC, on behalf of PSEG Long Island, coordinates and hosts an Energy Efficiency conference that occurs on an 18-month basis. The conference is open to all customers and contractors and provides networking opportunities, informative seminars with industry leaders, market trends, emerging technologies, and highlights project successes. In 2019, attendance reached over 600, with nearly half attendees being customers. The event is well regarded throughout Long Island as the energy efficiency event of the year. It is an excellent platform for the CEP to build camaraderie with participating lead partners and customers, as well as an opportunity for customers and lead partners to stay abreast on industry trends.

PSEG Long Island continues to promote contractors who have been certified as Prime Efficiency Partners. The PEPs drive small business participation, making it paramount to train, vet, and promote these contractors. The introduction of the Prime Efficiency Partner network in 2017 has enabled the program to touch more small business customers and bring awareness to the programs. Contractors wishing to participate in the Fast Track program and be designated Prime must meet specific business criteria, complete trainings, and meet the strict program requirements. The launch of the Prime Efficiency Partner program has also played a crucial role in maintaining customer satisfaction. Lead partners who wish to achieve the prime designation are able to attend scheduled trainings to learn more about the program and become closer to achieve the designation.

The Fast Track Program is a prescriptive rebate program available to all customers who wish to participate in the CEP lighting program through an engaging and speedy solution. All commercial customers may participate in this offering, regardless of rate code or building size. The total rebate for a Fast Track project may not exceed $5,000. The Fast Track Program is unique in that only Prime

Efficiency Partners may participate, and pre-approvals and pre-inspections are not required. Allowing Prime Efficiency Partners only in the Fast Track offering ensures the customer has a positive program experience with a PSEG Long Island trained and vetted contractor.

All lead partners, including PEPs, are subject to Quality Control Evaluation procedures as necessary, in an effort to ensure continued quality installations for commercial customers.

A.2.7.3 *Target Market*

All nonresidential customers in the PSEG Long Island service territory.

A.2.7.4 *Measures and Incentives*

Custom and Custom Retrofit project rebates are calculated by the PSEG Long Island CEP Project Screening Tool. Rebates are calculated based on four primary inputs: kW, kWh, incremental cost, and fossil fuel impacts, with overall $/MMBtu and percentage of project cost as caps. The default rebate calculation methodology in the tool is set at $/MMBtu, however, the tool allows $/kW, $/kWh, Simple Payback, %Incremental cost and weighted as selections that require project specific approval. For all other measures, rebates are set per market conditions, and may adjust during the year as the market changes. All measures are subject to cost/benefit screening prior to launch.

A.2.7.5 *Outreach*

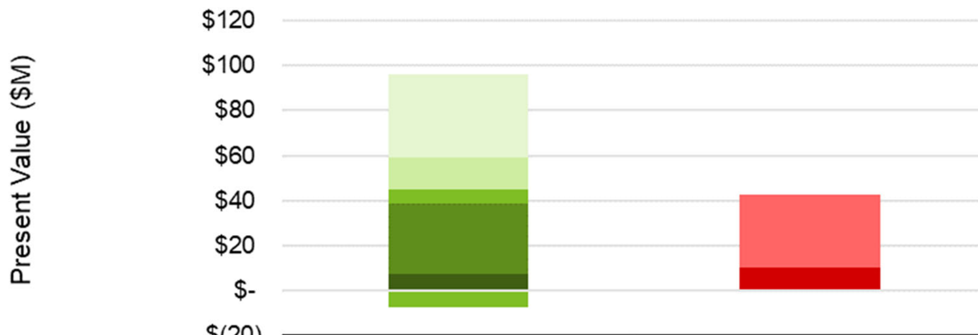
The CEP team offers free energy assessments to all eligible PSEG Long Island commercial customers. Customers who request an assessment are contacted by a CEP Energy Consultant (EC) to arrange a site visit or virtual site visit. During the assessment, the EC conducts an audit of the facility, provides the customer with program information and recommendations, and leaves behind program collateral like a checklist complete with energy saving tips. The checklist covers the four core measure groups Lighting, HVAC, Compressed Air, and Refrigeration.

The CEP team also works closely with participating lead partners to drive program awareness and interacts with customers at Community Partnership Program (CPP) events to promote different program offerings and connect one on one with PSEG Long Island customers.

A.2.7.6 *Business Case*

The Commercial programs have a SCT benefit-to-cost ratio of 2.39 and RIM benefit-to-cost ratio of 0.18. A list of the value streams considered in the societal benefit-cost analysis is detailed in Figure A-7.

Figure A-7. Present Value Benefits and Costs of SCT – Commercial



	Benefit	Cost
Fuel Switching Benefits	(7.26)	-
Net Avoided SO2 and NOx	(0.000105)	-
Net Avoided CO2	37.15	-
Avoided Distribution Capacity Infrastructure	14.20	-
Avoided Transmission Capacity Infrastructure	5.87	-
Avoided Energy (LBMP)	31.58	-
Avoided Generation Capacity Cost (AGCC)	7.29	-
Participant DER Cost	-	32.48
Program Administration Costs	-	10.41
Total	88.82	42.90

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	(7.26)	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	(0.000105)	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	37.15	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	14.20	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	5.87	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	31.58	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	7.29	
8	**Participant Distributed Energy Resources (DER) Cost**	Includes cost of incremental equipment and installation.		32.48
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		10.41
	Total Benefits		**88.82**	
	Total Costs			**42.90**
	SCT Ratio		**2.07**	

NPV = Net present value
LBMP = Location-based marginal pricing

A.2.8 Clean Green Schools

PSEG Long Island is proposing to collaborate with NYSERDA on the Clean Green Schools Initiative. The goal of NYSERDA's Clean Green Schools Initiative is to help public schools that traditionally lack resources to invest in infrastructure improvements become healthier, more productive learning environments. This program aims to improve the environmental sustainability of those schools by reducing school energy loads, decarbonizing their building portfolio, improving indoor air quality (IAQ), and providing clean energy educational opportunities.

For purposes of this program effort, decarbonization is defined as reducing or eliminating carbon dioxide emissions from school buildings through electrification, energy load reduction, energy efficiency and conservation, switching to switching to low carbon fuels (e.g., biofuels), and/or installation of renewable technologies (e.g., solar). IAQ services are defined as those that address the quality of indoor breathing air. Good indoor air quality affects occupant health, well-being, productivity, and learning by reducing the risk of infectious disease transmission, asthma/allergens, and sickness, and increasing the amount of clean air. For purposes of this program, IAQ evaluation is focused on ensuring ventilation is considered when recommending or installing decarbonization measures as part of a project and that the resulting conditions will provide adequate outdoor air exchanges and filtration levels.

While NYSERDA's Clean Green Schools Initiative is funded in part through RGGI funds, meaning all eligible school buildings in New York State can make use of the program, it is expected that demand by applicants will be greater than available funds for PSEG Long Island service territory-based buildings. By partnering with NYSERDA over a multi-year period, PSEG Long Island can add supplemental funds to ensure greater participation by interested customers, thereby decarbonizing more school buildings in disadvantaged communities while leveraging the program design and structure that NYSERDA has created.

A.2.8.1 *Program Delivery*

NYSERDA's statewide Clean Green Schools Initiative will be broken up into two tracks. Tracks I and II will launch simultaneously under one Program. Track II will have two due dates, one in mid-2022 and one in early 2024. PSEG Long Island proposes to partner on Track II projects for the second due date in early 2024.

Track II provides funding for schools to implement projects that decarbonize their building portfolio, such as comprehensive retrofits that impact energy consumption and overall building load, electrification readiness projects, and conversion of central heating and/or cooling plants to clean energy technologies such as heat pumps. Example eligible projects:

- Clean Heating and Cooling Projects:
  - Ground Source Heat Pump (GSHP), Air Source Heat Pump (ASHP) and Variable Refrigerant Flow (VRF) installations that provide space heating and/or cooling.
- Capital Projects to Move Towards Decarbonization:
  - Comprehensive retrofits that impact energy consumption and overall building load
  - Electrification of building systems (e.g., kitchen equipment & domestic hot water heaters)
  - Building electrification readiness projects:
    - High performance building envelope (e.g., air sealing, insulation, window film)
    - Heating/cooling projects
    - Conversion of distribution systems (e.g., steam to hot water) to support potential future electrification
  - Transition to low carbon fuels (e.g., biofuel blends)
  - Ineligible Projects:
    - System conversion to natural gas or other fossil fuel is ineligible.
    - Full system replacements to new fossil fuel-based systems are ineligible.
- The following supporting upgrades/efforts are eligible when completed in combination with any eligible activities shown above:
  - Building Automation Systems
  - Energy storage systems
  - Renewable energy technologies
  - Clean electricity purchase with emphasis on the use of community solar or "Green" energy service provider
  - Window replacement
  - Upgrading existing electrical infrastructure (e.g., electrical panel upgrades & equipment service infrastructure)
  - Building ventilation system and filtration system capital projects
  - Lighting upgrades
  - Resiliency measures
  - Clean transportation projects

The program will offer additional funding to support clean energy educational and professional development opportunities when included in an eligible project application. Some examples of activities the program supports include incorporating project-based learning to educate students and the community, training for faculty and students, involving students or faculty in completing the project, and apprenticeships/internships.

A.2.8.2 *Target Market*

PSEG Long Island intends to provide supplemental funds to address the overflow of worthy applications, but customer-facing communications, including outreach and other program processes, will be handled by NYSERDA.

All existing public school buildings across New York State that are designated as High-Needs by the New York State Education Department or located in a disadvantaged community are eligible for the Clean Green Schools Initiative. PSEG Long Island would prioritize those school buildings located in defined disadvantaged communities.

A.2.8.3 *Measures and Incentives*

Under NYSERDA's program design, applicant project costs are up to 100% funded, net of funding from sources including state aid, federal funding, or any other funding source, with a minimum award of $500,000 and capped at $3,000,000 per building and $5,000,000 per district. Schools/districts can receive up to another $1,000,000 for projects that either propose to install ground source heat pumps or that propose to fully electrify both space and domestic hot water equipment with any of the Clean Heating and Cooling Technologies listed above. Schools may receive additional funding in Track II to support Clean Energy Educational and Professional Development Activities, which are up to 100% funded, capped at $30,000 per eligible building and $100,000 per eligible district.

Given the nature of the multi-year partnership with NYSERDA and the longer lifecycle of comprehensive decarbonization projects envisioned by this program, there are no savings expected in 2023. PSEG Long Island is budgeting $50,000 in the event that there are incidental costs in launching the program.

A.2.8.4 *Business Case*

Since this is a multi-year partnership, savings and most of the associated spending are expected beyond 2023. There is no BCA for 2023.

A.2.9 Pay for Performance

PSEG Long Island collaborated with NYSERDA, EE service providers, and other supporting partners to transform the way investments in EE are made through the Pay for Performance Pilot initiative. Pay for Performance has emerged nationally as a market-based approach to delivering and paying for EE solutions. Supported by policy reforms, PSEG Long Island's deployment of AMI, and growth in sophisticated data analytics, the pay for performance model shifts the focus away from individual measure savings estimates to whole building metered savings. Payment is restructured to align with realized energy savings. Under this initiative, approximately $300,000 in awards was made available for projects that would result in 1100 MMBtus of annual reductions in energy use for participating PSEG Long Island customers.

Unlike the existing EE programs that use measure-specific (e.g., light bulbs, appliances, etc.) rebates and incentives, this initiative would compensate service providers over a 3-year period targeted for measured EE that accrues from portfolios of residential and commercial customers that undergo EE upgrades and operational improvements. This flexible approach to investing in EE would allow service providers to innovate and provide a more comprehensive approach to meeting customers' energy needs, while fostering a longer-term relationship that can result in additional investments in EE.

A.2.9.1 *Notable Changes*

NYSERDA is in the process of launching or supporting pay for performance pilots in other service territories, including Consolidated Edison and National Grid. In February 2022, PSEG Long Island leveraged those learnings by partnering with NYSERDA to issue an RFP to competitively select one or more service providers. These service providers, known as Portfolio Managers, would engage with customers to implement EE solutions. At the conclusion of the RFP period, there were no responses furnished by the prospective bidders. Subsequent feedback based on interviews with bidders revealed four primary takeaways. First, the pilot scope was seen as too limiting owing to the small potential customer count and geographic area and ultimately award size. Second, respondents stated that there was a mismatch between the pilot award size and the level of work required to bid; given the requirements of the scope of work and RFP, the hurdles to apply were not seen as a reasonable investment. Third, consistent feedback was given that pay for performance is less attractive as a business opportunity to the market because of the inherent risk that is shifted from utilities to bidders. And lastly, issues were cited with prior experience from Pay for Performance and other REV-like opportunities in New York State that dissuaded bidders from engaging with this pilot. Based on the response from the market, PSEG Long Island is suspending current efforts to pursue a pay for performance pilot.

A.2.10 Dynamic Load Management Programs

LIPA introduced three DLM programs to the electric tariff effective April 1, 2016. The DLM Tariff was designed to be consistent with the objectives of REV by providing innovative market-based solutions to T&D system needs. The program is effective during the capability period, which is May 1-September 30.

The DLM Tariff consists of a direct load control tariff program and a demand response tariff program. The Bring Your Own Device Smart Savers Program allows residential and small commercial customers who have smart thermostats to provide PSEG Long Island with control of their thermostats during times of high electric demand periods to curtail overall electric demand. In exchange for this control, participating customers will receive a one-time $85 enrollment payment. In subsequent years, the customer will receive an annual $25 performance payment linked to their actual curtailment usage, when customers fully participate in a minimum of 50% of the curtailment events during the capability period.

The second part of the DLM tariff is a more traditional DR tariff, which emulates the New York Independent System Operator’s Emergency Demand Response and Special Case Resource programs. Under this tariff, medium-to-large size commercial customers would sign up and be obligated to the Company to reduce their load by a specified amount when called on either through a day-ahead notification or in reliability need times two hours ahead.

For the Direct Load Control Smart Savers Program, PSEG Long Island will communicate with each participating customer’s individual thermostat; and for the Commercial System Relief Program/ Distribution Load Relief Program, PSEG Long Island will instruct aggregators and/or customers to curtail during a DR event one day or two hours in advance dependent on whether the Commercial System Relief Program or Distribution Load Relief Program is initiated.

A.2.10.1 *Notable Changes*

Effective June 1, 2019, LIPA approved the use of battery storage (whether standalone or paired with other distributed energy resources) for both residential and commercial customers as part of the DLM tariff program. Eligible customers enrolled in the DLM tariff program with qualifying battery storage and battery storage systems paired with solar equipment will receive a reservation payment locked in for up to 10 years from the date of initial enrollment.

A.2.10.2 *Program Delivery*

To implement the DLM Tariffs, EnergyHub was contracted to administer the tariff requirements and implement the program.

Direct Load Control Smart Savers Program

The Smart Savers Program will pay customers $85 to enroll their smart thermostat in the program. The thermostat will allow PSEG Long Island to curtail usage of central air conditioning systems in the home or small business. In addition, the customer will receive a $25 payment for each subsequent year they remain in the program and fully participate in a minimum of 50% of the curtailment events during the capability period. The customer must utilize an approved thermostat provider and install the device in their home or business. Approved thermostat providers market and promote the program to potential customers, and customers enroll in the Smart Savers Program through the smart thermostat electronic application. The device is an internet-connected thermostat that is registered with the program enrollment administrator and is linked to PSEG Long Island through an enrollment portal. PSEG Long Island initiates a load reduction curtailment day when appropriate, during the program capability period.

Commercial System Relief Program

The Commercial System Relief Program (CSRP) creates the opportunity for market forces to identify and implement load relief measures that would allow PSEG Long Island to avoid building new distribution capacity at specific locations along the T&D system. The goal of the program is to have the market provide such solutions and for PSEG Long Island to spend less on T&D upgrades and projects.

The CSRP offers several features to both individual customers and aggregators of customers in the program. The program scope consists of:

- Monthly reservation payments per kW for commitments to reduce load on 21 hours' notice. The current reservation payment is $5/kW/month.
- Performance payments for each kWh of energy curtailed during a called event, lasting up to 4 hours. The current performance payment is $0.25 per kWh reduced during a curtailment event.

Customers and aggregators may participate by reducing or deferring load, or utilizing dispatchable onsite generation options, to meet the commitment to reduce their load on the system. Generation options must meet strict emissions criteria to be eligible for the program. AMI metering is also required of all customers enrolled in the program. All load reduction provided during a called curtailment event will be quantified using a Customer Base Load methodology, which requires detailed usage information made available on a timely basis.

Distribution Load Relief Program

The Distribution Load Relief Program (DLRP) creates the opportunity to reduce electric load in certain designated zones or "load pockets" on the PSEG Long Island system. These load pockets will be identified, when necessary, by PSEG Long Island and posted to the PSEG Long Island website. The DLRP offers:

- Monthly reservation payments per kW for commitments to reduce load on two-hours' notice. The current reservation payment is $3/kW/month of enrolled load reduction.
- Performance payments for each kWh of energy curtailed during a called event lasting up to 4 hours. The current performance payment for load reduced during a called event is $0.25 per kWh.

Customers and aggregators may participate by reducing or deferring load, or utilizing dispatchable onsite generation options, to meet the commitment to reduce their load on the system. Generation options must meet strict emissions criteria to be eligible for the program. AMI metering is also required of all customers enrolled in the program. All load reduction provided during a called curtailment event will be quantified using a Customer Base Load methodology, which requires detailed usage information made available on a timely basis.

A.2.10.3 *Customer Enrollment/Financial Impacts*

The financial impacts of the three proposed programs are expected to be favorable to ratepayers on a net present value basis. Each of the three programs involves payments that are less than the costs that can be avoided from their implementation, producing a net benefit to ratepayers; the Benefit-Cost Analysis is included in the Dynamic Load Management Annual Report. Table A-18 shows the enrollment activity as of January 1, 2021.

Table A-18. DLM Tariff Customer Enrollment as of January 1, 2022

Program	2021 Cumulative Customers	2021 Cumulative MW Reduction	Curtailment Events (2021 Cumulative)	Curtailment Events (Cumulative)
Smart Savers Program	32,886	32.9	7	24
CSRP/DLRP	302	28.5	5	24
DLRP Only	302	27.9	3	7

In 2021, all customers enrolled in CSRP are also enrolled in DLRP. The MW reductions shown in Table A-19 reflect the performance from both programs combined and are not additive.

Table A-19. DLM Tariff Customer Enrollment 5 Year Forecast

	2023	2024	2025	2026	2027
DLC MW Enrolled	44.9	50.9	56.9	62.9	68.9
CSRP MW Enrolled	37.7	43.3	49.8	57.3	65.9
DLRP MW Enrolled	37.7	43.3	49.8	57.3	65.9
Total MW Enrolled	**82.6**	**94.2**	**106.7**	**120.2**	**200.7**
DLC Customer Payment	$1,482,150	$1,632,150	$1,782,150	$1,932150	$2,082,150
CSRP Customer Reservation Payment	$942,281	$1,083,623	$1,246,167	$1,433,092	$1,647,500
DLRP Customer Reservation Payment	$565,369	$650,174	$747,700	$859,855	$988,500
CSRP/DLRP Customer Performance Payment	$150,765	$173,380	$199,387	$229,295	$263,600
Total Customer Payments	**$3,140,565**	**$3,539,327**	**$3,975,404**	**$4,454,392**	**$4,981,750**

*All Customer Payments are collected through the Power Supply Charge and therefore do not impact the operating budget.

A.2.11 Behavioral Initiative (HEM)

This Home Energy Management Program that was launched in the third quarter of 2017 supports statewide goals under REV to create a cleaner, more resilient, and affordable energy system for all New Yorkers. Through regulatory overhaul, REV encourages the cleanest, most advanced, and efficient power system operation. State programs supporting clean energy are being redesigned to accelerate market growth and unlock private investment. This program will advance progress toward New York State's goals of achieving a 40% reduction in GHG levels and a 185 TBtu increase in statewide EE by 2030.

A.2.11.1 *Program Delivery*

PSEG Long Island's overarching objective of this program is to motivate and inspire PSEG Long Island customers to increase their understanding of all aspects of their energy needs and take active control of their energy usage. Indications are that this program has resulted in increased customer satisfaction, increased customers' understanding and ability to manage their energy usage, increased customer adoption of existing EE offerings, improved customer access to energy efficient products and clean energy service providers (i.e. EE, residential solar, community solar, demand response and related services), and has fostered the development of marketplace solutions such as smart thermostats which will induce deeper clean energy penetration and leverage greater private investments in such efforts. Outcomes undergoing evaluation include:

- Customer bill savings
- Reduction in GHGs
- Clean energy penetration including increased use of renewable and low carbon sources,
- Demand and capacity reductions
- Greater private sector investment in clean energy solutions,
- Customer satisfaction

This HEM program enables residential customers to realize cost-effective verifiable EE savings, while also increasing awareness and adoption of applicable programs, products and services, and increases customer satisfaction.

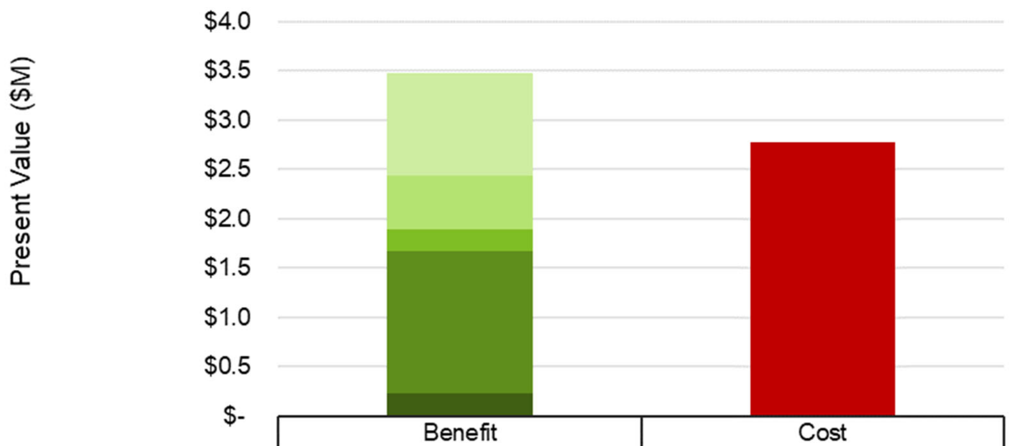
A.2.11.2 *Notable Changes*

PSEG Long Island expects the Home Energy Report treatment group to number approximately 450,000 residential customers in 2023. All residential customers will have access to the HEM MyEnergy engagement portal and online Home Energy Assessment function.

A.2.11.3 *Business Case*

HEM has a SCT benefit-to-cost ratio of 1.22 and RIM benefit-to-cost ratio of 0.22. A list of the value streams considered in the BCA is detailed in Figure A-8.

Figure A-8. Present Value Benefits and Costs of SCT – HEM



	Benefit	Cost
Net Avoided CO2	1.04	-
Avoided Distribution Capacity Infrastructure	0.54	-
Avoided Transmission Capacity Infrastructure	0.23	-
Avoided Energy (LBMP)	1.44	-
Avoided Generation Capacity Cost (AGCC)	0.23	-
Program Administration Costs	-	2.77
Total	3.48	2.77

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	1.04	
2	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.54	
3	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.23	
4	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	1.44	
5	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.23	
6	**Program Administration Costs**	Includes contractors fee, labor, and evaluation costs.		2.77
	Total Benefits		**3.48**	
	Total Costs			**2.77**
	SCT Ratio		**1.25**	

NPV = Net present value
LBMP = Location-based marginal pricing

Appendix B. Benefit-Cost Analysis Handbook

This Benefit-Cost Analysis Handbook has been developed in conjunction with efforts undertaken by New York State Investor Owned Utilities in response to the State of New York Public Service Commission (NYPSC) direction to the Joint Utilities (JU)[41] to develop and file Benefit-Cost Analysis (BCA) Handbooks by June 30, 2016, as a requirement of the Order Establishing the Benefit-Cost Analysis Framework (*BCA Order)*.[42]

This BCA Handbook is intended to set forth PSEG Long Island's approach to Benefit-Cost analysis for purposes of screening annual Energy Efficiency Portfolio Plans and will be updated in the future to reflect any approach used for the potential procurement of distributed energy resources as non-wire alternatives to planned Transmission and Distribution capital investments ("Non-Wire Solutions").

B.1 Introduction

The BCA Handbook provides methods and assumptions that will be used to inform BCA for the above types of expenditure and strives to be consistent with statewide methodologies adopted by the JU unless operational or procurement practices would require an alternative approach

The BCA Handbook endeavors to meet the following foundational goals

- Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
- Avoid combining or conflating different benefits and costs.
- Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
- Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
- Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

B.1.1 Application of the BCA Handbook

The evaluation of cost-effectiveness of programs and alternative solutions compared to traditional infrastructure investments and utility investments is a complex and sometime difficult analysis which requires the consideration of many factors – some which lend themselves to relatively clear quantification and some which are more challenging. Similarly, a like for like comparison cannot necessarily always be completed for each aspect of a potential solution.

In any such analysis it is important to recognize that the end results are highly dependent upon the forecasting, financial and framework assumptions which are used for both the base case and program and/or opportunity being compared to the base case.

This BCA Handbook includes key assumptions, data sources and overall approach methods which will be used for conducting a BCA for the Energy Efficiency Program Portfolio. Included are methodologies and descriptions of how benefits and costs are calculated as well as how different means of cost effectiveness testing can be conducted.

[41] For the purpose of this document, Joint Utilities includes Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation.

[42] *BCA Order*: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

The BCA Handbook attempts to provide a common approach to conducting BCA across investments in programs, projects and portfolios while also noting instances where individual investment characteristics may need to be considered.

This BCA Handbook is envisioned to be a dynamic work which may be amended going forward as implementation of the BCA process reveals details or aberrations which may not have been foreseen in the initial drafting of the Handbook.

Lastly, the BCA Handbook will identify the source of data to be used based upon applicability of project. Table B-1 lists the statewide data and sources to be used for BCA and referenced in this Handbook.

Table B-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[43]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports[44]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[45]
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 2[46]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[47]

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table B-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table B-2. Utility-Specific Assumptions

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital	[Utility-specific] Rate Case
Losses	[Utility-specific] Electric Loss Report
Marginal Cost of Service	[Utility-specific] Marginal Cost of Electric Delivery Service Study
Reliability Statistics	DPS: Electric Service Reliability Reports[48]
Restoration Costs	[Utility-specific]
Avoided Generation Capacity Cost (AGCC)	Utility-specific
Avoided Cost of Energy (ACE)	Utility-specific

[43] The 2020 Load & Capacity Data report is available at: https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/. Supporting data can be found on the NYISO website in the Load & Capacity Data Report folder in the Planning Reports library section: https://www.nyiso.com/library.
http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

[44] Historical ancillary service costs are available at: http://mis.nyiso.com/public/P-6Blist.htm.

[45] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

[46] The hourly allowance price assumptions for the 2020 CARIS Phase 2 study will be available in the CARIS Input Assumptions folder within Economic Planning Studies at: https://www.nyiso.com/cspp. Until such time that the finalized 202- CARIS 2 data is published, the utilities will employ the 2017 CARIS Phase 1 results.

[47] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year and post the results on DMM under case 14-M-0101.

[48] The 2020 Annual Electric Service Reliability Report is available at: https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/d82a200687d96d3985257687006f39ca/$FILE/2020%20Electric%20Reliability%20Report.pdf.

The New York general and utility-specific assumptions that are included in this first version of the BCA Handbook (as listed in Table B-1 and Table B-2) are typically values by zone or utility system averages. In subsequent versions, application of the BCA Handbook may be enhanced by including more granular data, for example with respect to location (e.g., zone, substation, or circuit) or time (e.g., seasonal, monthly, or hourly) if available.

The BCA methodology underlying the BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project and portfolio types with some adjustments as necessary. BCA development will require the standard inputs provided in the BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.
The BCA Handbook is anticipated to be revisited for updates every two years. However, it is anticipated that Utility Provided Data for energy and capacity will updated annually. Additionally, during the two year interim, the Handbook and associated appendices may be updated at any time such changes are deemed to be necessary.

B.1.2 BCA Handbook Version

This 2022 BCA Handbook v4.0 provides techniques for quantifying the benefits and costs identified in the BCA Order. Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

B.1.3 Structure of the Handbook

The four remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

- **Section B.2. General Methodological Considerations** describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this BCA Handbook.
- **Section B.3 Relevant Cost-Effectiveness Tests** defines each cost-effectiveness test included in the BCA Framework. These include the Societal Cost Test (SCT), the Utility Cost Test (UCT), and the Rate Impact Measure (RIM). The *BCA Order* specifies the SCT as the primary measure of cost-effectiveness.
- **Section B.4 Benefits and Costs Methodology** provides detailed definitions, calculation methods, and general considerations for each benefit and cost.
- **Section B.5 Characterization of DER profiles** discusses which benefits and costs are likely to apply to different types of DER and provides examples for a sample selection of DERs.
- **Section B.6 Utility-Specific Assumptions** includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

B.2 General Methodological Considerations

This section describes key issues and challenges that that must be considered when developing project- or portfolio-specific BCAs. These considerations are incorporated into the benefit and cost calculation methods presented in **Section** B.4**.**

B.2.1 Avoiding Double Counting

A BCA must be designed to avoid double counting of benefits and costs. Double counting can be avoided by 1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio and 2) clear definition and differentiation between the benefits and costs included in the analysis.

Sections B.2.1.1 and B.2.1.2 discuss these considerations in more detail.

B.2.1.1 *Accounting of Benefits and Costs Across Multiple Value Streams*

The BCA Handbook provides a methodology for calculating the benefits and costs resulting from utility investments as portfolios of projects and programs or as individual projects or programs. A project or program will typically involve multiple technologies, each associated with specific costs. Each technology also provides one or more functions that result in quantified impacts, which are valued as monetized benefits.

Investments may be made in technologies that do not result in direct benefits but instead function to enable or facilitate the realization of benefits from additional measures or technologies. Some technologies may both enable or enhance the benefits of other technologies and result in direct benefits though a parallel function. It is important not to double-count benefits resulting from multiple measures or technologies functioning together to achieve an impact. Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Over time, investments made as part of previous projects or portfolios may also enable or enhance new projects.

Multiple technologies may result in impacts that produce the same benefits. For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility's distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The utility BCA must also address the non-linear nature of grid and DER project benefits. For example, impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. If there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW-worth of capacity deferral credit for that feeder. As another example, the incremental improvement on reliability indices may diminish as more automated switching projects are in place.

B.2.1.2 *Benefit Definitions and Differentiation*

A key consideration identified in performing a BCA is to avoid double counting of benefits and costs by appropriately defining each benefit and cost.

As discussed in Section B.3, the *BCA Order* identified 16 benefits to be included in the cost-effectiveness tests. The calculation methodology for each of these benefits is provided in Section B.4. Two bulk system benefits, Avoided Generation Capacity Costs (AGCC) and Avoided ACE, result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided ACE benefits may be confused with other benefits identified in the *BCA Order* that must be calculated separately.

Defined below are the avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided ACE and differentiate them from the impacts that should be counted as separate Avoided Transmission Losses and Avoided Distribution Losses benefits. Also provided below is the differentiation between the transmission capacity values embedded as components of the AGCC and Avoided ACE values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided ACE values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

Table B-3 provides a list of potentially overlapping AGCC and Avoided ACE benefits.

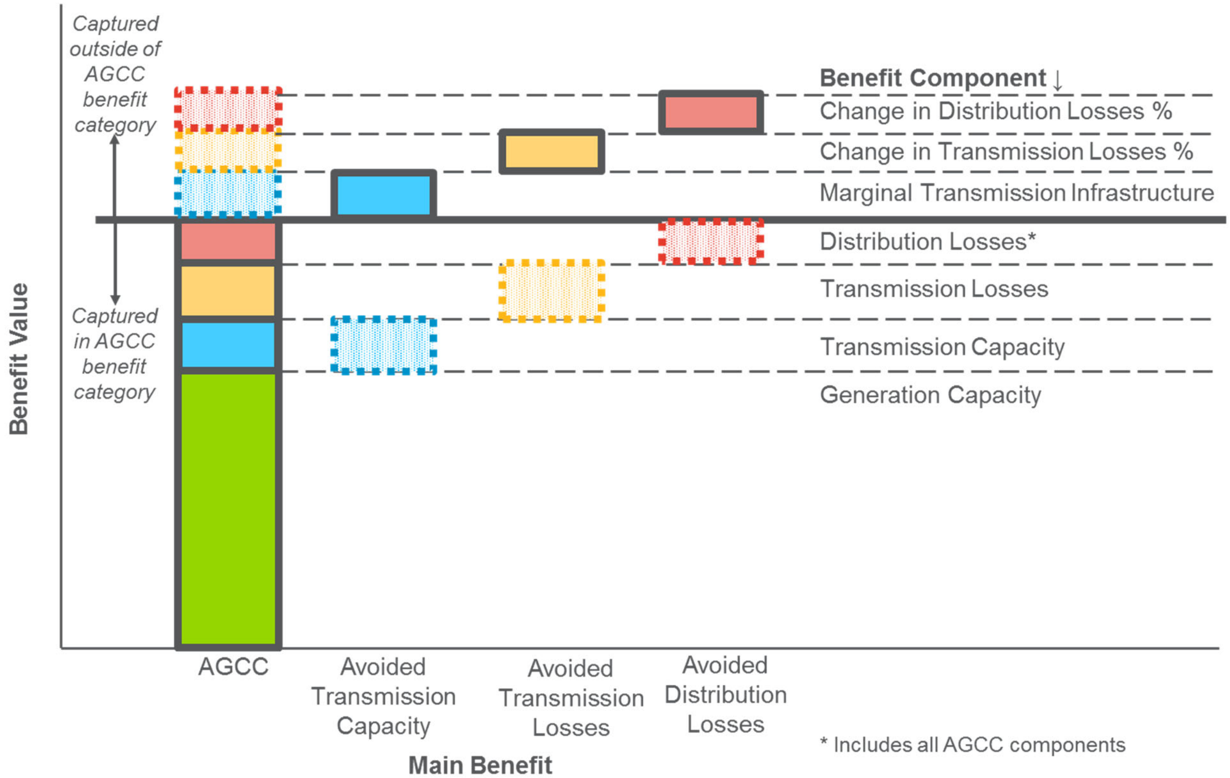
Table B-3. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs	Avoided Transmission Capacity Avoided Transmission Losses Avoided Distribution Losses
Avoided ACE (analogous to LBMP)	Net Avoided CO_2 Net Avoided SO_2 and NO_x Avoided Transmission Losses Avoided Transmission Capacity Avoided Distribution Losses

Benefits Overlapping with Avoided Generation Capacity Costs

Figure B-1 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure B-1. Benefits Potentially Overlapping with Avoided Generation Capacity Costs (Illustrative)



Source: Guidehouse (formerly Navigant Consulting)

In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit but included in calculation of a separate benefit. The benefit shown above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission tosses.[49] Additionally, distribution losses can affect the calculation of AGCC, depending on the project location on the system.[50] The AGCC calculation accounts for these distribution losses.

If a project changes the electrical topology and therefore changes the transmission loss percent itself, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

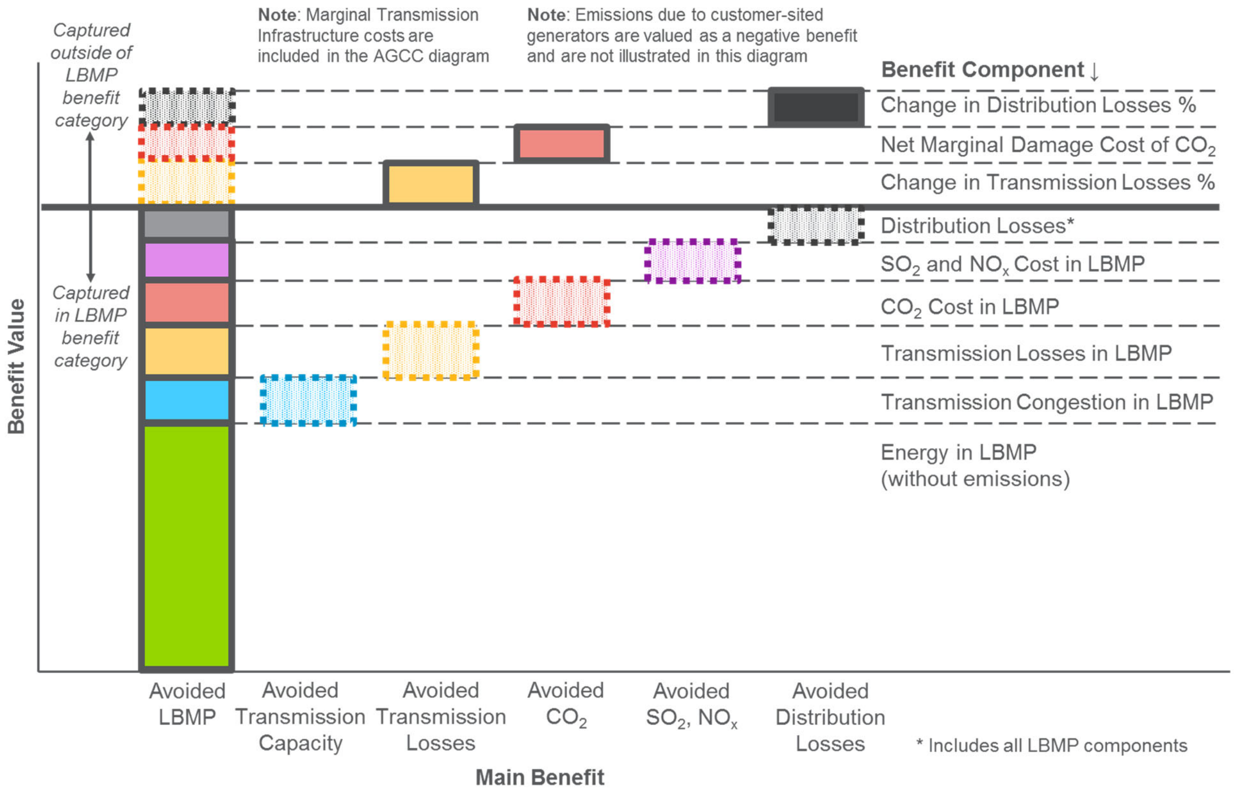
Benefits Overlapping with Avoided ACE

Figure B- 2 graphically illustrates potential overlaps of benefits pertaining to Avoided ACE.

[49] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

[50] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

Figure B- 2. Benefits Potentially Overlapping with Avoided ACE Benefit (Illustrative)



Source: Guidehouse (formerly Navigant Consulting)

In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided ACE benefit include costs for factors beyond simple energy cost per megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided ACE benefit:

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the ACE
- Transmission-level loss costs which are embedded in the ACE
- Compliance costs of various air pollutant emissions regulations including the value of CO_2 via the Regional Greenhouse Gas Initiative and the values of SO_2 and NO_x via cap-and-trade markets which are embedded in the ACE

Additionally, distribution losses can affect ACE purchases, depending on the project location on the system, and should gross up the calculated ACE benefits.[51] To the extent a project changes the electrical topology and changes the distribution loss percent itself, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided ACE benefit.

[51] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the ACE purchases due to higher losses.

B.2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section B.4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, the variable losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section B.4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity of energy and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters.
- **Loss Percent (%)** are the total fixed and/or variable[52] quantity of losses between relevant voltage levels divided by total electricity send-out unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from "loss percent". The loss factor is 1 / (1 - Loss Percent).

For consistency, the equations in Section B.4 follow the same notation to represent various locations on the system:

- "r" subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[53]
- "i" subscript represents the interface of the distribution and transmission systems.
- "b" subscript represents the bulk system which is the level at which the values for AGCC and ACE are provided.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $\mathrm{Loss\%}_{\mathrm{b}\rightarrow\mathrm{r}}$ would represent the loss percent between the bulk system ("b") and the retail delivery or connection point ("r"). In this example, the loss percent would be the sum of the distribution secondary, distribution primary and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

B.2.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the course of the project.

[52] In the BCA equations outlined in Section B.4 below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.

[53] Transmission in this context refers to the distribution utility's sub-transmission and internal transmission.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. Because benefits of grid modernization projects accrue over many years, baselines must be valid across the same time horizon. This introduces a few points that merit consideration:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, in the rest of the State, the Commission has directed that Avoided ACE should be calculated based on NYISO's CARIS Phase 2 economic planning process base case ACE forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends. *Note – in PSEG Long Island's case unless the project was of significant size (~ 100 kW) there generally is no wholesale market implication.*
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation, and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.
- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may take place independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment, expected system performance, or both. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions underlying the existing baseline.

B.2.4 Normalizing Impacts

In addition to establishing an appropriate baseline, normalizing impact data presents similar challenges. This is particularly true for distribution-level projects, where system performance is significantly affected by external conditions beyond that which occurs on the distribution system. For instance, quantifying the impact of technology investment on reliability indices would require the baseline data to be representative of expected feeder reliability performance. This is a challenging task, as historical data would require weather adjustments and contemporaneous data would be drawn from different, but similar, feeders.

A distribution feeder may go through changes that could influence feeder performance independent of the technologies implemented. For instance, planned outages due to routine maintenance activities or outages due to damages from a major storm could impact reliability indices and changes in the mix of customer load type (e.g., residential vs. commercial and industrial), which may impact feeder peak load.

B.2.5 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[54]

B.2.6 Granularity of Data for Analysis

The most accurate assumptions to use for assessing a BCA would leverage suitable location or temporal information. When the more granular data is not available, an appropriate annual average or system average may be used, if applicable in reflecting the expected savings from use of DER.

More granular locational or temporal assumptions are always preferred to capture the savings more accurately from use of a resource. However, the methodology included in the BCA Handbook would accommodate appropriate system averages in cases where their use is required.

B.3 Relevant Cost-Effectiveness Tests

The *BCA Order* indicates the BCA Handbook shall include "description of the sensitivity analysis that will be applied to key assumptions."[55] As Section B.4 presents, there is a discussion of each of the benefits and costs, and a sensitivity analysis can be performed by changing selected parameters.

The largest benefits for DER are typically the bulk system benefits of Avoided ACE or AGCC. A sensitivity of ACE, $/MWh, could be assessed by adjusting the ACE by +/-10%. Relevant Cost-Effectiveness Tests The *BCA Order* states that the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table B-4.

Table B-4. Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The *BCA Order* positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

[54] *BCA Order*, pg. 2
[55] *BCA Order*, Appendix C, pg. 31.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and ratepayers. Some projects may not provide benefits to the utility and ratepayers, even if it is beneficial to society as a whole. It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that the impact is of a "magnitude that is unacceptable".[56]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section B.2.

Table B-5 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the *BCA Order*. The subsections below provide further context for each cost-effectiveness test. The Benefit Costs considered in the screening of the Energy Efficiency Program Portfolio are bolded in the below table.

[56] *BCA Order*, pg. 13.

Table B-5. Summary of Cost-Effectiveness Tests by Benefit and Cost

Section #	Benefit/Cost	SCT	UCT	RIM
	Benefit			
B.4.1.1	Avoided Generation Capacity Costs†	✓	✓	✓
B.4.1.2	Avoided ACE‡	✓	✓	✓
B.4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
B.4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
B.4.1.5	Avoided Ancillary Services	✓	✓	✓
B.4.1.6	Wholesale Market Price Impacts**		✓	✓
B.4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
B.4.2.2	Avoided O&M	✓	✓	✓
B.4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
B.4.3.1	Net Avoided Restoration Costs	✓	✓	✓
B.4.3.2	Net Avoided Outage Costs	✓		
B.4.4.1	Net Avoided CO_2‡	✓		
B.4.4.2	Net Avoided SO_2 and NO_x‡	✓		
B.4.4.3	Avoided Water Impacts	✓		
B.4.4.4	Avoided Land Impacts	✓		
B.4.4.5	Net Non-Energy Benefits***	✓	✓	✓
	Cost			
B.4.5.1	Program Administration Costs	✓	✓	✓
B.4.5.2	Added Ancillary Service Costs	✓	✓	✓
B.4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
B.4.5.4	Participant DER Cost	✓		
B.4.5.5	Lost Utility Revenue			✓
B.4.5.6	Net Non-Energy Costs**	✓	✓	✓

† See Section 0 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 0 for discussion of potential overlaps in accounting for these benefits.

*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefits in each year of the analysis period (i.e., how much will it change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section B.4.

- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A 2% annual inflation rate should be assumed unless otherwise specified.

B.3.1 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions, and net non-energy benefits)

A majority of the benefits included in the *BCA Order* can be evaluated under the SCT because their impact can be applied to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants. in the *BCA Order*:

"Wholesale markets already adjust to changes in demand and supply resources, and any resource cost savings that result are reflected in the SCT. Any price suppression over and above those market adjustments is essentially a transfer payment -- simply a shift of monetary gains and losses from one group of economic constituents to another. No efficiency gain results if, for example, generators are paid more or less while consumers experience equal and offsetting impacts. Therefore, the price suppression benefit is not properly included in the SCT beyond the savings already reflected there."[57]

B.3.2 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the UCT. Utilities in New York do not currently receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

B.3.3 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other ratepayers as Lost

[57] *BCA Order*, pg. 24

Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

B.4 Benefits and Costs Methodology

Each subsection below aligns with a benefit or cost listed in the *BCA Order*. Each benefit and cost includes a definition, equation, and general considerations.

There are four types of benefits which are further explained in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use consumers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

Additionally, there are four types of costs that are also considered in the BCA Framework and explained in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues, and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives
- Societal: External costs for incorporation in the SCT

In this version of the Handbook, for energy, operational, and reliability-related benefits and costs,[58] it is assumed that impacts generate benefits/costs in the same year as the impact. In other words, there is no time delay between impacts and benefits/costs. However, for capacity and infrastructure benefits and costs,[59] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2020, the AGCC benefit would not be realized until 2021.

B.4.1 Bulk System Benefits

B.4.1.1 *Avoided Generation Capacity Costs*

Avoided Generation Capacity Costs are due to reduced coincident system peak demand. This benefit is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[60] It is assumed that the benefit is realized in the year following the peak load reduction impact.

[58] Energy, operational, and reliability-related benefits and costs include: Avoided ACE, the energy component of Avoided Transmission Losses, Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation), the energy portion of Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, Net Avoided Restoration Costs, Net Avoided Outage Costs , the energy component of Distribution Losses, Net Avoided CO2, Net Avoided SO2 and NOx, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, and Net Non-Energy Costs.

[59] Capacity, infrastructure, and market price-related benefits and costs include: Avoided Generation Capacity Costs, the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, the capacity portion of the Wholesale Market Price Impact, Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

[60] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

The avoided capacity, in $/kw-yr, is calculated using Market Manager, a sophisticated and proprietary PSEG Long Island software program that calculates forward market prices for both Long Island and Rest of State (ROS) as well as the net market capacity costs to LIPA. The calculations are based on the NYISO demand curves, NYISO Gold Book forecasted loads, forecasted installed capacity levels in Long Island and New York State, as well as the estimated values for locational requirements and installed reserve margin as established by NYS Reliability Council and NYISO.

For the purpose of quantifying the net market capacity costs, two Market Manager scenarios are analyzed. The first scenario assumes the current load forecast, the second scenario is based upon a load forecast decrease of 100 MW relative to the first scenario. The difference in the net market capacity costs to LIPA is then calculated. The results are shown on an annual unitized basis. This methodology captures both the decremental cost of supply for the reduction in needed capacity that results from the change in load as well as the overall change to LIPA's base capacity purchases.

Benefit Equation, Variables, and Subscripts

Equation B-1 presents the benefit equation for Avoided Generation Capacity Costs. This equation follows "Variant 1" of the Demand Curve savings estimation described in the 2015 Congestion Assessment and Resource Integration Study (CARIS) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI = K.

Equation B-1. Avoided Generation Capacity Costs

$$\text{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\text{PeakLoad}_{Z,Y,r}}{1\text{-Loss\%}_{Z,Y,b\to r}} * \text{SystemCoincidenceFactor}_{Z,Y} * \text{DeratingFactor}_{Z,Y} * \text{AGCC}_{Z,Y,b}$$

The indices of the parameters in Equation B-1 include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

Δ**PeakLoad**$_{Z,Y,r}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%}_{Z,b\to r}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table B-22.

$\mathbf{SystemCoincidenceFactor}_{Z,Y}$ **(dimensionless)** captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\mathbf{DeratingFactor}_{Z,Y}$ **(dimensionless)** is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$AGCC_{Z,Y,b}$ (\$/MW-yr) represents the annual AGCCs at the bulk system ("b") based on forecast of capacity prices for the wholesale market provided by DPS Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of \$/kW-mo, which must be converted to \$/MW-yr to match the peak load impact in MW. To convert units, the summer and winter \$/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to \$/MW-yr. AGCC costs are calculated based on the NYISO's capacity market demand curves, using supply and demand by NYISO zone, Minimum Locational Capacity Requirements (LCR), and the Reserve Margin.

General Considerations

The AGCC forecast provided by Staff is based on capacity market demand curves using the demand forecasts and available supply from NYISO's Load & Capacity Data report. CARIS can be used for guidance on how demand curves are applied to the AGCC forecast.[61] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[62] for more details on ICAP.

Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section B.4.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and accounted for losses prior to applying the AGCC valuation parameter. The "nameplate" impact (i.e. $\Delta PeakLoad_{Z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

B.4.1.2 *Avoided ACEs*

Avoided ACE is avoided energy purchased.

[61] 2019 CARIS Phase 1 Study Appendix. https://www.nyiso.com/documents/20142/2226108/2019-CARIS-Phase1-Appendix-Final.pdf/7d061d58-85c5-6319-2407-3e2bdddcee71. The study is performed bi-annually and the most recent can be found under Planning Reports, Economic Planning Studies at: https://www.nyiso.com/library

[62] The NYISO Installed Capacity Manual is available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338

Due to past practices with respect to the procurement of capacity and energy, certain impacts and costs are not applicable to PSEG Long Island. Unlike the remainder of the Investor Owned Utilities, PSEG Long Island is generally "long" on capacity and has contracts in place for the bulk of its capacity requirements. Similarly, PSEG Long Island has contracts in place for the bulk of its energy requirements. As a result of this, the impact of LBMP is significantly dampened compared to the rest of the New York electric utilities.

The avoided energy cost, in $/MWh, is calculated using GE MAPS (Multi-area Production Software) program. The MAPS program is used to calculate production costs given most up to date load forecasts, existing and future generation, and transmission network. The model used by PSEG Long Island consists of the 4-pool system: NY, NE, PJM Classic, and parts of Ontario, Canada.

For the purpose of quantifying the avoided energy costs, two MAPS scenarios are analyzed. The first scenario assumes the current load forecast, the second scenario is based upon a 100 MW peak and corresponding energy requirement decrease relative to the first scenario. The difference in LIPA's production cost between the two scenarios is divided by the change in energy to obtain the unitized avoided energy in $/MWh.

Benefit Equation, Variables, and Subscripts

Equation B-2 presents the benefit equation for Avoided ACE:

Equation B-2. Avoided ACE

$$\mathrm{Benefit}_{\mathrm{Y}}=\sum_{\mathrm{Z}}\sum_{\mathrm{P}}\frac{\Delta\mathrm{Energy}_{\mathrm{Z,P,Y,r}}}{1-\mathrm{Loss\%}_{\mathrm{Z,b\rightarrow r}}}*\mathrm{ACE}_{\mathrm{Z,P,Y,b}}$$

The indices of the parameters in Equation B-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

ΔEnergy$_{Z,P,Y,r}$ (ΔMWh) is the difference in energy purchased at the retail delivery or connection point ("r") before and after project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the ACE location based on the losses between those two points on the system. This adjustment is performed based on the $Loss\%_{Z,b\rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Z,b\rightarrow r}}$ (%) is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table B-1.

ACE$_{Z,P,Y,b}$ ($/MWh) is the Avoided Cost of Energy, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). NYISO forecasts 20-year annual and hourly ACEs by zone. To determine time-differentiated ACEs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly ACE forecast by zone rather than developing an alternative forecast of time-differentiated ACEs based on shaping annual averages by zone from historical data. The NYISO hourly ACE forecast is a direct output from the CARIS Phase 2 modeling. To extend the ACE forecast beyond the CARIS planning period, if necessary, assume that the last year of the ACEs stay constant in real (inflation adjusted) $/MWh.

General Considerations

Avoided ACE benefits are calculated using a static forecast of ACE. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section B.4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak ACE by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

B.4.1.3 *Avoided Transmission Capacity Infrastructure and Related O&M*

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that are valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the ACE and the AGCC prices. Because static forecasts of ACEs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

Benefit Equation, Variables, and Subscripts

Equation B-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation B-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{Y+1} = \sum_{C} \frac{\Delta \mathrm{PeakLoad}_{Y,r}}{\mathrm{Loss\%}_{Y,b \rightarrow r}} * \mathrm{TransCoincidentFactor}_{C,Y} * \mathrm{DeratingFactor}_{Y} * \mathrm{MarginalTransCost}_{C,Y,b}$$

The indices[63] of the parameters in Equation B-3 include:

- C = constraint on an element of transmission system[64]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

[63] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[64] If system-wide marginal costs are used, this is not an applicable subscript.

$\Delta\mathbf{PeakLoad}_{\mathbf{Y,r}}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%}_{\mathbf{Y,b\rightarrow r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table B-22.

$\mathbf{TransCoincidentFactor}_{\mathrm{C,Y}}$ **(dimensionless)** quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $DeratingFactor_Y$). This input is project specific.

$\mathbf{DeratingFactor}_{\mathbf{Y}}$ **(dimensionless)** is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

$\mathbf{MarginalTransCost}_{\mathrm{C,Y,b}}$ **($/MW-yr)** is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table B-23.

General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study. Where the coincidence factor is in the control of the operator (e.g., CVR, utility-controlled batteries), an engineering study may not be needed.

Some transmission capacity costs are already embedded in both ACE and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in ACE and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in significant over- or under-valuation of the benefits or costs and may result in no savings in utility costs for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Table B-23 include both capital and O&M, and cannot be split between the two benefits. Therefore, care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section B.4.2.2.

B.4.1.4 *Avoided Transmission Losses*

Avoided Transmission Losses is the benefit that is realized when a project changes the topology of the transmission system and results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided ACE and Avoided Generation Capacity benefits as described above in Sections B.4.1.2 and B.4.1.1. In actuality, both the ACE and AGCC would adjust to a change in system losses in future years; however, the static forecast used in this methodology does not capture these effects.

Benefit Equation, Variables, and Subscripts

Equation B-4 presents the benefit equation for Avoided Transmission Losses:

Equation B-4. Avoided Transmission Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{ACE}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\rightarrow i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i} = \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{post}}$$

The indices[65] of the parameters in
Equation B-4 include:

- Z = NYISO zone (for ACE: A → K; for AGCC: NYC, LHV, LI, ROS[66])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

[65] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[66] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

SystemEnergy$_{\mathbf{Z,Y+1,b}}$ **(MWh)** is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b"), which includes transmission and distribution losses. Note that total system energy is used for this input, not the project-specific energy, because this benefit is only included in the BCA when the system topology is changed resulting in a change in the transmission loss percent, which affects all load in the relevant area.

ACE$_{\mathbf{Z,Y+1,b}}$ **($/MWh)** is the ACE, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated ACEs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly ACE forecast by zone rather than developing an alternative forecast of time-differentiated ACEs based on shaping annual averages by zone from historical data. The NYISO hourly ACE forecast is a direct output from the CARIS Phase 2 modeling. To extend the ACE forecast beyond the CARIS planning period, if necessary, assume that the last year of the ACEs stay constant in real (inflation adjusted) $/MWh.

SystemDemand$_{\mathbf{Z,Y,b}}$ **(MW)** is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in transmission losses percent, which affects all load in the relevant zone.

AGCC$_{\mathbf{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level"[67] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

ΔLoss%$_{\mathbf{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table B-22.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses post-project.

General Considerations

Transmission losses are already embedded in the ACE. This benefit is incremental to what is included in ACE and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

[67] "Transmission level" represents the bulk system level ("b").

The energy and demand impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the ACE component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the timing of the benefits relative to the impacts.

B.4.1.5 *Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)*

Avoided Ancillary Services benefits may accrue to selected DERs that are willing and qualify to provide ancillary services to NYISO. NYISO could purchase ancillary services from these DERs in lieu of conventional generators at a lower cost without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO.

DER causes a reduction in load but will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are periodically set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DERs may have the potential to provide a new distribution-level ancillary service such as the voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DERs. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DERs as well as the operations and communications system to communicate with and effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services unless and until the utilities can cost-effectively build the systems to monitor and dispatch DERs to capture net distribution benefits.

Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of this benefit is project specific.

Frequency Regulation

Equation B-5 presents the benefit equation for frequency regulation:

Equation B-5. Frequency Regulation

$$\text{Benefit}_Y = \text{Capacity}_Y * \text{n} * (\text{CapPrice}_Y + \text{MovePrice}_Y * \text{RMM}_Y)$$

The indices of the parameters in Equation B-5 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the amount of annual average frequency regulation capacity when provided to NYISO by the project. The amount is difficult to forecast.

$\mathbf{n}$ **(hr)** is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$\mathbf{MovePrice_Y}$ **($/ΔMW)**: is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

$\mathbf{RMM_Y}$ **(ΔMW/MW·hr)**: is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation B-6 presents the benefit equation for spinning reserves:

Equation B-6. Spinning Reserves

$$\text{Benefit}_Y = \text{Capacity}_Y * n * \text{CapPrice}_Y$$

The indices of the parameters in Equation B-6 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project. The amount is difficult to forecast.

$\mathbf{n}$ **(hr)**: is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly spinning reserve capacity price. Default value uses the two-year historical average spinning reserve pricing by region.

General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

NYISO in late 2015 changed the number of regions for Ancillary Services from two to three and two-year historical data is not available for all three regions. Thus, assume that EAST and SENY are equal to the historical data for EAST. The corresponding NYISO zones for EAST are F – K, and the corresponding zones for WEST are A – E.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period. To avoid the complication of the change in regions, the two-year historical average is based on November 1, 2013 through October 31, 2015.

The NYISO Ancillary Services Manual suggests that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.

B.4.1.6 *Wholesale Market Price Impact*

Wholesale Market Price Impact includes the benefit from reduced wholesale market prices on both energy (i.e., ACE) and capacity (i.e., AGCC) due to a measure, project, or portfolio. ACE impacts will be provided by Staff and are determined using the first year of the most recent CARIS database to calculate the static impact on wholesale ACE of a 1% change in the level of load that must be met.[68] ACE impact will be calculated for each NYISO zone. AGCC price impacts are characterized using Staff's ICAP Spreadsheet Model.

Benefit Equation, Variables, and Subscripts

Equation B-7 presents the benefit equation for Wholesale Market Price Impact:

Equation B-7. Wholesale Market Price Impact

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{Z}} (1 \text{ - } \mathrm{Hedging\%}) * (\Delta \mathrm{ACEImpact}_{\mathrm{Z,Y+1,b}} * \frac{\Delta \mathrm{Energy}_{\mathrm{Z,Y+1,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Z,b \to r}}} + \Delta \mathrm{AGCC}_{\mathrm{Z,Y,b}} * \mathrm{ProjectedAvailableCapacity}_{\mathrm{Z,Y,b}})$$

The indices of the parameters in Equation B-7 include:

- Z = NYISO zone (A → K[69])
- Y = Year
- b = Bulk System

$\mathbf{Hedging\%}$ **(%)** is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms. Price hedging via long term purchase contracts should be considered when assessing wholesale market price impacts. The JU have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

$\mathbf{\Delta ACEImpact_{Z,Y+1,b}}$ **(Δ$/MWh)** is the change in average annual ACE at the bulk system ("b") before and after the project(s); requires wholesale market modeling to determine impact. This will be provided by DPS Staff.

$\mathbf{\Delta Energy_{Z,Y+1,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{Z,b \to r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b \to r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table B-22.

$\mathbf{WholesaleEnergy_{Z,Y,b}}$ **(MWh)** is the total annual wholesale market energy purchased by zone at the bulk system level ("b"). This must represent the energy at the ACE.

$\mathbf{\Delta AGCC_{Z,Y,b}}$ **(Δ$/MW-yr)** is the change in AGCC price by ICAP zone calculated from Staff's ICAP Spreadsheet Model before and after the project is implemented. This value is determined based on the difference in zonal prices in Staff's ICAP Spreadsheet Model, "AGCC Annual" tab, based on a change in

[68] *BCA Order*, Appendix C, pg. 8.
[69] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

the supply or demand forecast (i.e., "Supply" tab and "Demand" tab, respectively) due to the project.[70] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

$\text{ProjectedAvailableCapacity}_{Z,Y,b}$ **(MW)** is the projected available supply capacity by ICAP zone at the bulk system level ("b") based on Staff's ICAP Spreadsheet Model, "Supply" tab, which is the baseline before the project is implemented.

General Considerations

Wholesale market price impacts or demand reduction induced price effects are project specific based on the size and shape of the demand reduction. ACE market price impacts will be provided by Staff and will be determined using the first year of the most recent CARIS database to calculate the static impact on ACE of a 1% change in the level of load that must be met in the utility area where the DER is located. These impacts must be considered in the benefit calculation once available. The capacity market price impacts can be calculated using Staff's ICAP Spreadsheet Model. The resultant price effects are not included in SCT but would be included in RIM and UCT as a sensitivity.

It is assumed that Wholesale Market Price Impacts do not result in benefits for more than one year, as these markets will respond quickly to the reduced demand, quickly reducing the benefit. It is also assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact, and the energy portion of Wholesale Market Price Impacts will produce benefits in the same year as the impact.

B.4.2 Distribution System Benefits

B.4.2.1 *Avoided Distribution Capacity Infrastructure*

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

Benefit Equation, Variables, and Subscripts

Equation B-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation B-8. Avoided Distribution Capacity Infrastructure

$$\text{Benefit}_Y = \sum_V \sum_C \frac{\Delta \text{PeakLoad}_{Y,r}}{1 - \text{Loss\%}_{Y,b \rightarrow r}} * \text{DistCoincidentFactor}_{C,V,Y} * \text{DeratingFactor}_Y * \text{MarginalDistCost}_{C,V,Y,b}$$

The indices of the parameters in Equation B-8 include:

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[71]
- V = Voltage level (e.g., primary, and secondary)

[70] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

[71] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta \mathbf{PeakLoad}_{\mathbf{Y,r}}$ **(ΔMW)** is the nameplate demand reduction of the project at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%}_{\mathbf{Y,b \to r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table B-22 This parameter to used to adjust the $\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}$ parameter to the bulk system level.

$\mathbf{DistCoincidentFactor}_{\mathbf{C,V,Y}}$ **(dimensionless) is a project specific input that** captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system. This input is project specific.

$\mathbf{DeratingFactor}_{\mathbf{Y}}$ **(dimensionless) is a project specific input that** is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system. This input is project specific.

$\mathbf{MarginalDistCost}_{\mathbf{C,V,Y,b}}$ **($/MW-yr)** is the marginal cost of the distribution equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table B-23.

General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used when and wherever possible. Using system average marginal costs to estimate avoided transmission and distribution infrastructure need may result in significant over- or under-valuation of the benefits or costs, and may result in no savings in utility costs for customers. Coincidence and derating factors would be determined by a project-specific engineering study.

Avoided distribution infrastructure benefits for a specific location are realized only if a DER project or portfolio of DER projects meets the engineering requirements for functional equivalence (i.e., DER reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project. The DSIP identifies specific areas where a distribution upgrade need exists and where DERs could potentially provide this benefit.

Use of system average avoided cost assumptions may be required in some situations, such as system-wide programs or tariffs. These values are provided in Table B-22

The timing of benefits realized from peak load reductions are project and/ or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, the constraint is relieved and benefits should not be realized from that point forward.

The marginal cost of distribution capacity values provided in Table B-23 include both capital and O&M and cannot be split between the two benefits. Therefore, whenever these system average values are used, care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section B.4.2.2.

B.4.2.2 *Avoided O&M*

Avoided O&M includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit (Section B.4.2.1). As discussed above, marginal cost studies include O&M and that O&M is not separately included in this benefit. Therefore, this benefit includes reduced expenses not tied to avoided or deferred distribution system investment from DER. This benefit may capture O&M savings from investments to improve customer service that reduces phone calls to the call center or O&M savings from migrating toward advanced meter functionality reducing meter reading costs. At this time, for most DER projects this benefit will be zero. For example, DER may reduce equipment loading, which reduces failure rates, but somewhat higher equipment loading may have led to the installation of new equipment with lower O&M costs. Further analysis is required to understand how DER would impact O&M.

Benefit Equation, Variables, and Subscripts

Equation B-9Equation B-9. Avoided O&M presents the benefit equation for Avoided O&M Costs:

Equation B-9. Avoided O&M

$$\text{Benefit}_{\text{Y}} = \sum_{\text{AT}} \Delta\text{Expenses}_{\text{AT,Y}}$$

The indices of the parameters in Equation B-9 include:

- AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

$\mathbf{\Delta Expenses_{AT,Y}}$ **($\Delta$$)**: Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

General Considerations

Distribution O&M benefits from DERs may be limited to instances where DERs can avoid or defer new distribution equipment, which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section B.4.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be zero for most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely. Labor and crew rates can be sourced using the utility's activity-based costing system or work management system, if that information is available

B.4.2.3 *Distribution Losses*

Avoided Distribution Losses are the incremental benefit that is realized when a project changes distribution system losses, resulting in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the ACE and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of ACEs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%).

Benefit Equation, Variables, and Subscripts

Equation B-10 presents the benefit equation for Avoided Distribution Losses:

Equation B-10. Avoided Distribution Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{ACE}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,i\rightarrow r} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r} = \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{post}}$$

The indices[72] of the parameters in Equation B-10 include:

- Z = NYISO zone (for ACE: A → K; for AGCC: NYC, LHV, LI, ROS[73])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathrm{SystemEnergy}_{Z,Y,b}$ **(MWh)** is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here, not the project-specific energy, because this benefit is only quantified when the distribution loss percent value is changed, which affects all load in the relevant part of the distribution system.

$\mathrm{ACE}_{Z,Y,b}$ **($/MWh)** is the ACE, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated ACEs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly ACE forecast by zone rather than developing an alternative forecast of time-differentiated ACEs based on shaping annual averages by zone from historical data. The NYISO hourly ACE forecast is a direct output from the CARIS Phase 2 modeling. To extend the ACE forecast beyond the CARIS planning period, if necessary, assume that the last year of the ACEs stay constant in real (inflation adjusted) $/MWh.

[72] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[73] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand for the portion of the retail location on the distribution system(s) (i.e., the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone. This parameter is grossed up to the bulk system level (i.e., location of the AGCC) based on the $\mathrm{Loss\%_{Z,b\rightarrow r}}$ parameter. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent, which affects all load in the relevant part of the distribution system.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system level ("b") based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\mathbf{\Delta Loss\%_{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table B-22.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

General Considerations

Distribution losses are already accounted for in the ACE and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of ACEs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses in the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses. Because losses data is usually only available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the ACE component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the time delay of benefits relative to the impacts.

B.4.3 Reliability/Resiliency Benefits

B.4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, as utilities will have to fix the cause of the outage regardless of whether the DER allows the customer operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours. Two methodologies to capture the potential value of programs or specific projects are identified below.

Benefit Equation, Variables, and Subscripts

Equation B-11 presents the benefit equation for Net Avoided Restoration Costs:

Equation B-11. Net Avoided Restoration Costs

$$\mathrm{Benefit}_{\mathrm{Y}} = -\Delta\mathrm{CrewTime}_{\mathrm{Y}} * \mathrm{CrewCost}_{\mathrm{Y}} + \Delta\mathrm{Expenses}_{\mathrm{Y}}$$

Where,

$$\Delta\mathrm{CrewTime}_{\mathrm{Y}} = \#\mathrm{Interruptions}_{\mathrm{base,Y}} * (\mathrm{CAIDI}_{\mathrm{base,Y}} - \mathrm{CAIDI}_{\mathrm{post,Y}} * (1 - \%\mathrm{ChangeSAIFI}_{\mathrm{Y}}))$$

$$\%\mathrm{ChangeSAIFI}_{\mathrm{Y}} = \frac{\mathrm{SAIFI}_{\mathrm{base,Y}} - \mathrm{SAIFI}_{\mathrm{post,Y}}}{\mathrm{SAIFI}_{\mathrm{base,Y}}}$$

SAIFI, CAIDI and SAIDI values could be utilized at the system level for projects/programs that are applicable across a total system basis, but can and should be substituted with more granular data for more localized and geographic specific projects that have more localized impacts. Other reliability metrics if available and applicable may be utilized to better quantify certain reliability or resiliency benefits and costs.

There is no subscript to represent the type of outage in Equation B-11 because an average restoration crew cost that does not change based on the type of outage is assumed. However, the ability to reduce outages would be dependent on the outage type.

$\boldsymbol{\Delta\mathrm{CrewTime}_{\mathrm{Y}}}$ **(Δhours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages. A positive value represents a reduction in crew time.

$\boldsymbol{\mathrm{CrewCost}_{\mathrm{Y}}}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration.

$\boldsymbol{\Delta\mathrm{Expenses}_{\mathrm{Y}}}$ **(Δ$)** are the average expenses (e.g., equipment replacement) associated with outage restoration.

$\boldsymbol{\#\mathrm{Interruptions}_{\mathrm{base,Y}}}$ **(int/yr)** are the baseline (i.e., pre-project) number of sustained interruptions per year, excluding major storms. The system-wide five-year average number of interruptions excluding major storms is available from the annual Electric Service Reliability Reports.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. The system-wide five-year average CAIDI excluding major storms is available from the annual Electric Service Reliability Reports. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. This parameter would require an engineering study or model to quantify. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\%\mathbf{ChangeSAIFI_{Y}}$ **(Δ%)** is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value five-year average and excludes major storms. It is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

Equation B-12. Net Avoided Restoration Costs

$$\text{Benefit}_{\text{Y}} = \text{MarginalCost}_{\text{R,Y}}$$

The indices of the parameters in Equation B-12 include:

- R = Reliability constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$\text{MarginalDistCost}_{\text{R,Y}}$ **($/yr):** Marginal cost of the reliability investment. This value is very project- and location- and a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent to the reliability provided by the traditional distribution reliability investment; otherwise, the value of this benefit for DER is zero. When an individual or portfolio of DER is able to defer a distribution reliability investment, the value of the Avoided Distribution Capacity Infrastructure would likely be zero to avoid double counting.

General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline, not based on outside factors such as weather. The changes to these parameters should consider the appropriate context of the project, for example, impact to one feeder or impact to a portion of the distribution system. The baseline values should match the portion of the system impacted. In addition, one should consider the types of outage event and how the project may or may not address each type of outage event to inform the magnitude of impact.

In addition to being project-specific, calculation of avoided restoration costs is dependent on projection of the impact of specific investments affecting the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are unlikely. However, as measurement capabilities and DER experience evolve, utilities may be able to develop comparative evaluations of the reliability benefits of DER and traditional utility investments. Application of this benefit would be considered only for investments with validated reliability results.

B.4.3.2 *Net Avoided Outage Costs*

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

Benefit Equation, Variables, and Subscripts

Equation B-13 presents the benefit equation for Net Avoided Outage Costs:

Equation B-13. Net Avoided Outage Costs

$$\mathrm{Benefit_Y} = \sum_{\mathrm{C}} \mathrm{ValueOfService_{C,Y,r}} * \mathrm{AverageDemand_{C,Y,r}} * \Delta\mathrm{SAIDI_Y}$$

Where,

$$\Delta\mathrm{SAIDI_Y} = \mathrm{SAIFI_{base,Y}} * \mathrm{CAIDI_{base,Y}} - \mathrm{SAIFI_{post,Y}} * \mathrm{CAIDI_{post,Y}}$$

The indices of the parameters in Equation B-13 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{ValueOfService_{C,Y,r}}$ **($/kWh)** is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\mathbf{AvgDemand_{C,Y,r}}$ **(kW)** is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure. This would need to be identified by customer class, or by customer, if available. If the timing of outages cannot be predicted, this parameter can be calculated by dividing the annual energy consumption by 8,760 hours per year.

$\mathbf{\Delta SAIDI_Y}$ **(Δhr/cust/yr):** is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[74] Baseline system

[74] SAIDI = SAIFI * CAIDI

average reliability metrics can be found in the Company's annual Electric Service Reliability reports. A positive value represents a reduction in SAIDI.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

General Considerations

The value of the avoided outage cost benefit is to be customer class-specific, customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

At this time, the Standard Interconnection Requirements do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

B.4.4 External Benefits

B.4.4.1 *Net Avoided CO_2*

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[75] or the increase of CO_2 from onsite generation. The CARIS forecast of ACE contains a cost of carbon based on the Regional Greenhouse Gas Initiative (RGGI). Staff will provide a $/MWh adder to account for the net marginal damage cost of carbon that is not already captured in the ACE. This adder is based on the United States Environmental Protection Agency damage cost estimates for a 3% real discount rate. Staff then provides a $/MWh for the full marginal damage cost and the net marginal damage costs of CO_2. The net marginal damage costs is the full marginal damage cost less the cost of carbon embedded in the ACE.

[75] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided ACE, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

Benefit Equation, Variables, and Subscripts

Equation B-14 presents the benefit equation for Net Avoided CO_2:

Equation B-14. Net Avoided CO_2

$$\mathrm{Benefit_Y} = \mathrm{CO2Cost\Delta ACE_Y} - \mathrm{CO2Cost\Delta OnsiteEmissions_Y}$$

Where,

$$\mathrm{CO2Cost\Delta ACE_Y} = \left(\frac{\Delta \mathrm{Energy_{Y,r}}}{1 - \mathrm{Loss\%_{Y,b\rightarrow r}}} + \Delta \mathrm{Energy_{TransLosses,Y}} + \Delta \mathrm{Energy_{DistLosses,Y}}\right) * \mathrm{NetMarginalDamageCost_Y}$$

$$\Delta \mathrm{Energy_{TransLosses,Y}} = \mathrm{SystemEnergy_{Y,b}} * \Delta \mathrm{Loss\%_{Y,b\rightarrow i}}$$

$$\Delta \mathrm{Energy_{DistLosses,Y}} = \mathrm{SystemEnergy_{Y,b}} * \Delta \mathrm{Loss\%_{Y,i\rightarrow r}}$$

$$\Delta \mathrm{Loss\%_{Z,Y,b\rightarrow i}} = \mathrm{Loss\%_{Z,Y,b\rightarrow i,baseline}} - \mathrm{Loss\%_{Z,Y,b\rightarrow i,post}}$$

$$\Delta \mathrm{Loss\%_{Z,Y,i\rightarrow r}} = \mathrm{Loss\%_{Z,Y,i\rightarrow r,baseline}} - \mathrm{Loss\%_{Z,Y,i\rightarrow r,post}}$$

$$\mathrm{CO2Cost\Delta OnsiteEmissions_Y} = \Delta \mathrm{OnsiteEnergy_Y} * \mathrm{CO2Intensity_Y} * \mathrm{SocialCostCO2_Y}$$

The indices of the parameters in Equation B-14 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\mathbf{CO2Cost\Delta LBMP_Y}$ **($)** is the cost of CO_2 due to a change in wholesale energy purchased. A portion of the full CO_2 cost is already captured in the Avoided ACE benefit. The incremental value of CO_2 is captured in this benefit, and is valued at the net marginal cost of CO_2, as described below.

$\mathbf{CO2Cost\Delta OnsiteEmissions_Y}$ **($)** is the cost of CO_2 due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO_2, as described below.

$\mathbf{\Delta Energy_{Y,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b\rightarrow r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table B-22.

$\mathbf{\Delta Energy_{TransLosses,Y}}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section B.4.1.4 for more details. In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\Delta\mathbf{Energy}_{\mathbf{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section B.4.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

$\mathbf{NetMarginalDamageCost}_{\mathbf{Y}}$ **($/MWh)** is the "adder" Staff will provide to account for the full marginal damage cost of carbon that is not already captured in the forecast of ACE from CARIS. The ACE forecast from CARIS includes the cost of carbon based on the RGGI, but does include the SCC from the U.S. EPA.

$\Delta\mathbf{Loss\%}_{\mathbf{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). This represents the change in the transmission system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss}\%_{\mathbf{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent pre-project, which is found in Table B-22.

$\mathbf{Loss}\%_{\mathbf{Z,Y,b\rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent post-project, which is found in Table B-22.

$\Delta\mathbf{Loss\%}_{\mathbf{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss}\%_{\mathbf{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table B-22.

$\mathbf{Loss}\%_{\mathbf{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent post-project, which is found in Table B-22.

$\Delta\mathbf{Onsite}\mathrm{Energy}_{\mathbf{Y}}$ **(ΔMWh)** is the energy produced by customer-sited carbon-emitting generation.

$\mathrm{CO2Intensity}_{\mathbf{Y}}$ **(metric ton of CO_2 / MWh)** is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation. Note that there is a difference between metric tons and short tons[76].

$\mathbf{SocialCostCO2}_{\mathbf{Y}}$ **($ / metric ton of CO_2)** is an estimate of the total monetized damages to society associated with an incremental increase in carbon dioxide emissions. Annual values are provided by EPA, and are also located in Table A of Attachment B of the BCA Order. Per the BCA Order, the values associated with a 3% real discount rate shall be used. Note that Table A provides values in 2011 dollars; these values must be converted to nominal values prior to using the equation above.

[76] 1 metric ton = 1.10231 short tons

General Considerations

The equation above represents two sources of emissions based on: (1) a change in ACE purchases, which is valued at the $/MWh adder (i.e., $NetMarginalDamageCost_Y$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (e.g., such as combined heat and power [CHP]), which is valued at the social cost of carbon from EPA.

The energy impact is project-specific and should be linked to the impacts determined in the Avoided ACE benefit. The ACE impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be account for when determining the total change in ACE due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

The methodology outlined in this section to value Avoided CO_2 may change. The *BCA Order* indicates "utilities shall rely on the costs to comply with New York's Clean Energy Standard once those costs are known."[77]

B.4.4.2 *Net Avoided SO_2 and NO_x*

Net Avoided SO_2 and NO_x includes the incremental value of avoided or added emissions. The ACE already includes the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

Benefit Equation, Variables, and Subscripts

Equation B-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation B-15. Net Avoided SO_2 and NO_x

$$\text{Benefit}_{\text{Y}} = \sum_{\text{p}} \text{OnsiteEmissionsFlag}_{\text{Y}} * \text{OnsiteEnergy}_{\text{Y,r}} * \text{PollutantIntensity}_{\text{p,Y}} * \text{SocialCostPollutant}_{\text{p,Y}}$$

The indices of the parameters in Equation B-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{OnsiteEmissionsFlag_Y}$ is a binary (i.e., 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW is implemented as a result of the project.

$\mathbf{OnsiteEnergy_{Y,r}}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

$\text{PollutantIntensity}_{\text{p,Y}}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$\text{SocialCostPollutant}_{\text{p,Y}}$ **($/ton)** is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2.

[77] *BCA Order*, Appendix C, 16.

General Considerations

ACEs already include the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions –free DER.

Two values are provided in CARIS for NO_x costs: "Annual NO_x" and "Ozone NO_x." Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

B.4.4.3 *Avoided Water Impact*

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

B.4.4.4 *Avoided Land Impact*

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

B.4.4.5 *Net Non-Energy Benefits Related to Utility or Grid Operations*

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

B.4.5 Costs Analysis

B.4.5.1 *Program Administration Costs*

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

Benefit Equation, Variables, and ***Subscripts***

Equation B-16 presents the cost equation for Program Administration Costs:

Equation B-16. Program Administration Costs

$$\mathrm{Cost}_{\mathrm{Y}} = \sum_{\mathrm{M}} \Delta\mathrm{ProgramAdminCost}_{\mathrm{M,Y}}$$

The indices of the parameters in Equation B-16 include:

- M = Measure
- Y = Year

$\Delta\text{ProgramAdminCost}_{M,Y}$ is the change in Program Administration Costs, which may include one-time or annual incentives such as rebates, program administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

General Considerations

Program Administration Costs are program- and project-specific, therefore without a better understanding of the details it is not possible to estimate in advance the Project Administration Cost. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, utility-specific rebates and/or incentives, and costs of market interventions (e.g., state and federal incentives).

B.4.5.2 *Added Ancillary Service Costs*

Added Ancillary Service Costs occur when DER causes additional ancillary service cost on the system. These costs shall be considered and monetized in a similar manner to the method described in the B.4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation).

B.4.5.3 *Incremental Transmission & Distribution and DSP Costs*

Additional incremental T&D Costs are caused by projects that contribute to the utility's need to build additional infrastructure.

Additional T&D infrastructure costs caused shall be considered and monetized in a similar manner to the method described in Section B.4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M The potential for incremental T&D costs depends on the interconnection location, type of DER, and penetration of other DER in the area. These factors make estimating a value of incremental T&D costs in advance without project-specific information difficult.

Depending on the nature of a specific DER project the incremental costs could be borne by the interconnecting facility or shared among all ratepayers. For instance, a utility may need to make further investment in their T&D infrastructure, such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new DER assets.

In some situations enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

B.4.5.4 *Participant DER Cost*

Participant DER Cost includes the equipment and participation costs assumed by DER providers which need to be considered when evaluating the societal costs of a project or program. These costs are the full cost of the DER as program rebates, and incentives are included as part of Program Administration Costs.

The Participant DER Costs includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment, balance of system and labor for the installation. Operating costs include ongoing maintenance expenses.

Four DER example technologies with representative cost information are included in this section:

- Solar PV – residential (4 kW)
- Combined Heat and Power (CHP) – recip engine (100 kW)
- Demand Response (DR) – controllable thermostat
- Energy Efficiency (EE) – commercial lighting
- Electrification – residential heat pumps

All cost numbers presented herein should be considered representative estimates. Actual Participant DER costs will vary by project based upon factors including:

- **Make and model:** The DER owner typically has an array of products to choose from which have different combinations of cost and efficiency.
- **Type of installation:** The location of where the DER would be installed influences the capital costs, for example, ground-mounted or roof-mounted PV
- **Geographic location:** Labor rates, property taxes, and other factors vary across utility service areas and across the state

In addition, the specific DER provided herein are a small subset of the types of DER available in the market. Utilities intend to solicit DER costs in NWAs and other competitive solicitations, and will develop utility specific costs based on experience.

Solar PV Example

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. All cost parameters in Table B-6 for the intermittent solar PV example calculated based on information provided in the E3's NEM Study for New York ("E3 Report").[78] In this study, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in NY from 2003 to 2015. For a project-specific cost analysis, actual estimated project costs would be used.

Table B-6. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[79]	4,430
Fixed Operating Cost ($/kW)	15

Note: These are default values that would be used unless the DER provider supports project-specific estimates.

1. **Capital and Installation Cost:** Based on E3's estimate for NYSERDA of 2015 residential PV panel installed cost. For solar the $/kW cost usually includes both the cost of the technology and installation cost, which is the case in this example. Costs could be lower or higher depending on the size of project, installation complexity and location. This example assumes a 4 kW residential system for an average system in New York. This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.

[78] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

[79] This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.

2. **Fixed Operating Cost:** E3's estimate for NYSERDA of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. Cost parameter values were obtained from the EPA's Catalog of CHP Technologies[80] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can effect cost parameters that are not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural-gas fired CHP system. To reflect natural gas price fluctuation, Mid-Atlantic values from the Energy Information Administration Annual Energy Outlook[81] are used.

Table B-7. CHP Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/kW)	3,000
Variable Operating Cost ($/kWh)	0.025

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital. [82]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[83]

DR Example

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program. The capital cost is based on an average of Wi-Fi enabled controllable thermostats from Nest, Ecobee, and Honeywell.

Table B-8. DR Example Cost Parameters

Parameter	Cost
Capital Cost ($/Unit)	$233
Installation Cost ($/Unit)	$140

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Capital and Installation Costs:** These costs differ by thermostat model and capabilities, and as such should be considered representative. The installation costs estimates represent a New York system, but will vary substantially depending on the program nature.

[80] EPA CHP Report available at: https://www.epa.gov/chp/chp-resources
[81] https://www.eia.gov/outlooks/aeo/
[82] EPA CHP Report. pg. 2-15.
[83] EPA CHP Report. pg. 2-17.

2. **Operating Costs:** Assumed to be $0 for the DR asset participant based on comparison with the alternative technology.

EE Example

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting. Lighting cost estimates are based on the full cost of the measure, not the incremental cost over what is currently installed.

Table B-9. EE Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/Unit)	$80

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Installed Capital Cost:** Based on Guidehouse's review of manufacturer information and energy efficiency evaluation reports.

Electrification Example

The electrification examples include ducted air-source heat pumps (ASHP) and ductless mini-split heat pumps installed in a residential setting. Heat pump cost estimates are based on the full cost of the measure, not the incremental cost over what is currently installed. Avoided fuel oil, propane, or natural gas costs would need to be considered for the heat pumps displacing fossil fuel heating systems. To reflect fossil fuel price fluctuations, Mid-Atlantic values from the Energy Information Administration Annual Energy Outlook[84] are used. Delivered fuel prices are scaled to Long Island specific values reported by NYSERDA.[85,86]

Table B-10. Heat Pump Example Cost Parameters

Parameter	Cost
ASHP Installed Cost ($/Unit)	$11,570
Ductless Installed Cost ($/Unit)	$7,453

Note: These are illustrative estimates and would change as projects and locations are considered.

2. **Installed Capital Cost:** Based on Demand Side Analytics' review of projects in PSEG Long Island's territory.

B.4.5.5 *Lost Utility Revenue*

Lost Utility Revenue includes the distribution and other non-by-passable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-

[84] https://www.eia.gov/outlooks/aeo/

[85] https://www.nyserda.ny.gov/Researchers-and-Policymakers/Energy-Prices

[86] Aligned with the NYSERDA Commercial Baseline and Potential Study: "Because these fuels are not regulated, retail rates reflect the marginal societal costs." Commercial Baseline Appendix 2, page 12. NYSERDA https://www.nyserda.ny.gov/-/media/Migrated/Statewide-Commercial-Baseline-Study-Report/NYSERDA-CBS-Appendix-2-Potential-Study.pdf

related revenue “losses” due to a decrease in electricity sales or demand is recovered by marginally increasing the rate of electricity sales or demand to non-participating customers.

Lost utility revenue is not included in the SCT and UCT as the reduced participant revenues are offset by the increased non-participant revenues. Therefore, this cost is only included in the RIM. As DER reduces utility sales and the associated revenues, a revenue decoupling mechanism enables the utility to be made whole by recovering these lost revenues from other ratepayers.

The impact to non-participating customers would be estimated by evaluating the type of DER and the tariffs applicable to the affected customers.

B.4.5.6 *Net Non-Energy Costs*

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

B.5 Characterization of DER profiles

This section discusses the characterization of DERs using several examples, and presents the type of information necessary to assess associated benefits. Four *DER categories* are defined to provide a useful context, and specific example technologies within each category are selected for examination. The categories are: *intermittent*, *baseload*, *dispatchable* and *load reduction*. There are numerous potential examples of individual DERs within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in Table B-11 below. These four examples cover a useful, illustrative range of impacts that DERs can have on the various benefit and cost categories in the BCA Handbook.

Table B-11. DER Categories and Examples Profiled

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP
Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies that have been selected as examples are shown in Table B-12. Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example, DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed. Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak. Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table B-12.

Table B-12. Key Attributes of Selected DER Technologies

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The particular customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (e.g., <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER is capable of enabling a different set of benefits and incurs a different set of costs, as illustrated in Table B-13.

Table B-13. General applicability for each DER to contribute to each Benefit and Cost

#	Benefit/Cost	PV	CHP	DR	EE
	Benefits				
1	Avoided Generation Capacity Costs	●	●	●	●
2	Avoided ACE	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○
6	Wholesale Market Price Impacts	●	●	●	●
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○
	Costs				
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section B.4, each quantifiable benefit typically has two types of parameters. The parameters to monetize the value are generally unaffected by the DER being analyzed in the BCA (e.g., AGCC in $ per MW-yr), whereas other parameters asses the magnitude of underlying benefit and may vary by type of DER (e.g., system coincidence factor). Table B-14 identifies the parameters which are necessary to characterize DER benefits. As described in Section B.4, several benefits potentially applicable to DER require further investigation to estimate and quantify the impacts, and project-specific information before they can be incorporated into a BCA (e.g., Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

Table B-14. Key parameter for quantifying how DER may contribute to each benefit

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs	**SystemCoincidenceFactor**
2	Avoided ACE	**∆Energy (time-differentiated)**
3	Avoided Transmission Capacity Infrastructure	**TransCoincidenceFactor**
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	**∆Energy (annual)** **∆AGCC**
7	Avoided Distribution Capacity Infrastructure	**DistCoincidenceFactor**
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[87]
12	Net Avoided CO_2	**CO_2Intensity** (limited to CHP)
13	Net Avoided SO_2 and NO_x	**PollutantIntensity** (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

[87] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table B-15 further describes the key parameters identified in Table B-14.

Table B-15. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the Avoided Generation Capacity Costs benefit.[88] It captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability
Transmission Coincidence Factor[89]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
ΔEnergy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ΔEnergy is dependent on the type of DER (e.g., intermittent vs. baseload), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the ΔEnergy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding ACE data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[90]

[88] This parameter is also used to calculate the Wholesale Market Price Impact benefit.

[89] Bulk transmission effectively has the same coincidence factor as generation since non-project specific transmission benefits are included in the Avoided ACE and AGCC. This transmission coincidence factor is applicable for the Avoided Transmission Capacity Infrastructure and Related O&M benefit, which incorporates incremental value beyond what is included in the Avoided Generation Capacity Costs and Avoided ACEs benefits.

[90] Note also that annual change in bulk system energy is used in the calculation of Wholesale Market Price Impact benefit.

B.5.1 Coincidence Factors

Coincidence factors for DER are an important part of the benefit calculations and can be estimated in a variety of ways. What follows is a general approach for calculating the coincidence factors. Typical values are presented as examples in the sections below, however determining appropriate values for a specific project or portfolio may require additional information and calculation.

The first step is to identify the respective peak times for Bulk System, Transmission element or Distribution element as needed. Illustrations using a single peak hour are provided below.

B.5.1.1 *Bulk System*

According to the NYISO, the bulk system peaks generally occur during the afternoon hours of the hottest non-holiday weekday. The peak day might occur from May to October depending on the weather. For example, the New York Control Area (NYCA) peak typically occurs around hour ending 5 PM.Table B-16 below represents the NYCA peak dates and times for the last 5 years, for illustrative purposes, obtained from the 2021 Load and Capacity Data report.

Table B-16. NYCA Peak Dates and Times

Year	Date of Peak	Time of Peak
2016	8/11/2016	Hour Ending 5 PM
2017	7/19/2017	Hour Ending 6 PM
2018	8/29/2018	Hour Ending 5 PM
2019	7/20/2019	Hour Ending 5 PM
2020	7/27/2020	Hour Ending 5 PM

B.5.1.2 *Transmission*

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. In general, the benefits of a reduced transmission peak would be captured through the Avoided ACE and AGCC benefits.

B.5.1.3 *Distribution*

The distribution peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The distribution system coincidence factor is highly project specific. The distribution system serving predominantly large office buildings will peak at a different time or day than that of a distribution system that serves a residential neighborhood. The distribution system peak may differ or coincide with the NYCA system peak and the transmission peak. System-wide averages have been historically acceptable to use for some investment portfolios such as Energy Efficiency where the programs are broad based, and system-wide averages are provided in the Technical Resource Manual (TRM), which assumes a historical coincidence for the NYCA peak. Going forward, for investments that are more targeted in nature, a more localized coincidence factor is likely to be appropriate. The value of reducing the distribution peak is dependent on the location of constraints in the distribution equipment where utility capital investment may be needed. Note that in some cases with very local benefits objectives, even if the coincidence factor is high, the capacity value of a DER to the distribution system may be low or zero if no constrained element is relieved (e.g., no distribution investment is otherwise required in capacity in that location, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

B.5.2 Estimating Coincidence Factors

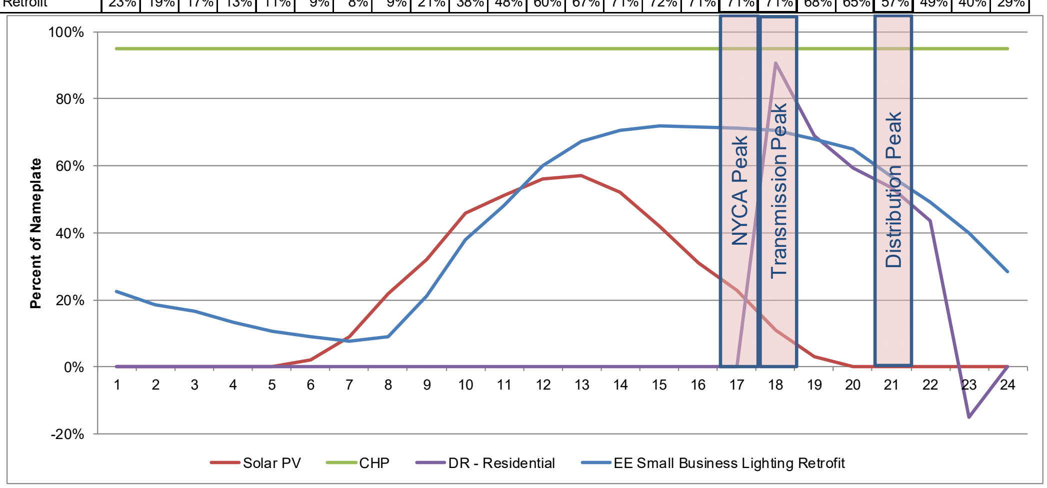
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the DER projects and network information for specific locations) and time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable in some situations.

One approach for estimating coincidence factors is to model the energy behavior of the DER on a time specific basis (e.g., hourly output) and normalize this behavior to the nameplate capacity. This time specific, normalized behavior can then be compared to the relevant peaks (i.e., system, transmission, and distribution) on the same time specific basis to determine the coincidence factors. The time basis can be done on an annual basis, using a 'typical day', or using a subset of hours that are appropriate that specific DER.

Figure B-3 provides an illustrative plot of the hourly DER output curves for a summer peak day as a graphical demonstration of the calculation method. The y-axis represents the percentage of DER output vs. the DER nameplate, and the x-axis shows the hour of the peak day. By using the Bulk System, Transmission or Distribution peak hour and the respective percentage of peak, the coincidence factors can be determined based on the type of resource.

Figure B-3. Illustrative Example of Coincidence Factors

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	-15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

The individual DER example technologies that have been selected are discussed below.[91]

The values for the DER examples have been compiled from various sources and each of these sources may apply different valuation techniques. Some sources performed extensive simulations to generate statewide averages, while others performed calculations on a variety of system specification assumptions. For example, the coincidence factors for the solar example were calculated in E3's NEM Study for New York ("E3 Report")[92] based on a simulation of a large number of solar systems across New York.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

B.5.3 Solar PV Example

Solar PV is selected to depict an intermittent DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions, were obtained from the E3 Report.

B.5.3.1 *Example System Description*

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. These details allow for an estimate of material and installation costs, but there are several other system details required to estimate system energy output, and therefore a full benefit analysis. Local levels of solar irradiance, panel orientation (azimuth angle from north, south, east, west), tilt (typically, 0°-25° for rooftop systems located in NY) and the addition of a tracking feature, as well as losses associated with the balance of system equipment (e.g., inverters, transformers) and system degradation over time each impact the system's capacity factor and coincidence factors with the bulk system, transmission and distribution.

The impact and value of solar output on system, transmission, and distribution systems must consider the intermittent behavior of solar generation. To conduct this analysis, an hourly profile of generation based on project-specific parameters, as well as corresponding system, transmission, and distribution load profiles, provide the information that is necessary to estimate the coincidence factors for this example DER technology. The values that follow in this section are for a system-wide deployment of solar PV.

B.5.3.2 *Benefit Parameters*

The benefit parameters in Table B-17 for the intermittent solar PV example are based on information provided in the E3 Report.

E3 determined utility-specific average values for coincidence and capacity factors. The statewide weighted-averages based on electricity delivered by utility are provided in Table B-17. These values are illustrative estimates that may be refined as more data becomes available. To calculate project-specific

[91] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DERs, such as those that might be procured to provide an NWA approach. Such a combination of project-specific DERs and distribution system information is less generalizable for assessing transmission and distribution coincidence factors, and less informative as an example than the individual DER examples selected. For example, when assessing NWAs it is necessary to assess their functional equivalence with traditional wired solutions. This requires understanding the potentially complex interactions between the DERs, assessing their joint reliability relative to that of traditional wired investment, and understanding the uncertainties in performance that may impact ability to maintain safe, reliable, economic energy delivery. The BCA handbook incorporates derating factors in various benefit calculations to account for these elements, but a discussion of those factors would complicate this section significantly, and so it was not included.

[92] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

benefit values, hourly simulations of solar generation, peak hours, and energy prices (ACE) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

Table B-17. Solar PV Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	36%
TransCoincidenceFactor	8%
DistCoincidenceFactor	7%
∆Energy (time-differentiated)	Hourly

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** This value represents the 'effective' percent of the nameplate capacity, 4 kW-AC, that reduces the system peak demand, resulting in an avoided generation capacity benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-43% depending on system azimuth and tilt angle.[93] It is acceptable to use the summer average because in this BCA, the AGCC is calculated based on the summer impact on-peak load (Section B.4.1.1).
2. **TransCoincidenceFactor:** The transmission coincidence factor included is for the New York average sub-transmission coincidence factor. This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the sub-transmission system.
3. **DistCoincidenceFactor:** The distribution coincidence factor is lowest. Residential distribution feeders and substations often peak during early evening hours when solar output is low.[94] This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the distribution system.
4. **∆Energy (time-differentiated):** As discussed above solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly ACEs.

B.5.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

B.5.4.1 *Example System Description*

CHP depicts a baseload DER where the electricity is generated at all hours, except during maintenance. The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100 kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full

[93] NYISO Installed Capacity Manual Version 4, March 2022, Summer Unforced Capacity Percentage – Solar Fixed Tilt Arrays) page 59. Available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

[94] E3 Report, "Based on E3's NEM Ratepayer Impacts Evaluation in California it was found (in a granular substation load analysis) that distribution peak loads are generally aligned with solar PV generation profiles in approximately 30% of the systems analyzed." PDF pg. 49.

electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's Catalog of CHP Technologies (EPA CHP Report).[95]

B.5.4.2 *Benefit Parameters*

Benefit parameters for the baseload CHP example are a combination of assumptions on system use and system characteristics.

Coincidence and capacity factors are derived from the assumption that the CHP is used as a baseload DER whereby the CHP system would be running at full capacity all the time, with the exception of downtime for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[96]

The carbon and criteria pollutant intensity can be estimated using the EPA's publically-available CHP Emissions Calculator.[97] "CHP Technology," "Fuel," "Unit Capacity" and "Operation" were the four inputs required. Based on the example, a reciprocating engine, fueled by natural gas, 100 kW in capacity operating at 95% of 8,760 hours/year.

To complete a project-specific analysis, actual design parameters and generation profiles would be needed to assess the likelihood of coincidence, emissions, and capacity factors.

Table B-18. CHP Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_X/MWh)	0.001
ΔEnergy (time-differentiated)	Annual average

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
4. **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section B.4.4.1).

[95] https://www.epa.gov/chp/chp-resources
[96] EPA CHP Report. pg. 2-20.
[97] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator

5. **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section B.4.4.2). There are no SO_2 emissions from burning natural gas.
6. **∆Energy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average ACE would be appropriate.

B.5.5 Demand Response Example

DR depicts an example of a dispatchable DER where the resource can be called upon to respond to peak demand.

B.5.5.1 *Example System Description*

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it is reduces demand on request from the system operator or utility.[98] Each DR program has unique requirements for notification time, length of demand reduction, number of calls, and frequency of calls. A DR resource is typically available only for limited hours in a year (e.g., <100 hrs). The major benefit from DR is ability to reduce peak demand. The particular use case or operational objective of the DR determines the value for its coincidence factors.

The coincidence factors shown below do not account for load or device availability. Load availability is defined as the percentage of total potential capacity that can be shed from the load connected to the DR system at the time the DR event is called. Device availability is defined as the ability the DR system to accurately receive the DR signal and control the load. These factors, multiplied by the total potential capacity of the DR asset, would produce the average demand reduction for the asset. Average demand reduction multiplied by the coincidence factor is then defined as the average peak coincidence demand. These values are not presented here but are project- and technology-specific and will differ substantially among DR technologies and loads. As such, project-specific analyses would need to consider the load and system availability, as well as response rate (as described above) to accurately determine the appropriate coincidence factors.

This DR example is designed to reduce system peak (consistent with most existing DR programs), thus the system coincidence factor is 1.0 such that the DR resource is called to reduce the system peak load.[99] Given the small number of calls annually, the coincidence factor with the system peak is assumed to be 1, while the coincidence factors for the transmission and distribution peaks is assumed to be 0.5 which is consistent with the assumption that this particular DR example is not targeted to be coincident with those peaks.[100]

As an alternative approach, to calculate the coincidence factors for a specific DR resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system with the peak demand of the other systems. Comparing the coincidence of the top 50 hours of total system load and top 50 hours of each feeder's load would produce the distribution coincidence factor for a DR project that targets system peak. Analysis should be based on data from the

[98] Some DR programs may be "dispatched" or scheduled by third-party aggregators.
[99] Note, the controllable load may not be operating at the time of peak.
[100] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BADA5E14E-9633-436E-8B1B-10DF4AB02913%7D.

Day-Ahead Market or Real-Time Market depending on the design of the DR program. Coincidence factors for DR projects should use the most recently available data.

The value of reduced energy use attributable to the DR asset can be calculated using the average ACE of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (e.g., 2 hour events, 4 hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

B.5.5.2 *Benefit Parameters*

The benefit parameters described here are assumed based on the example and considerations described above.

Table B-19. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	0.5
DistCoincidenceFactor	0.5
∆Energy (time-differentiated)	Average of highest 100 hours

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is assumed to be 1.0, based on the assumption that the DR system is called upon at the time of system peak.
2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[101] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.
3. **DistCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[102] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above. If instead the DR asset were used to defer distribution capacity, the coincidence factor could be as high as 1 (though the system coincident factor could then be as low as zero, since if the peak periods were to occur at the same time, the project could only be dispatched for one program).
4. **∆Energy (time-differentiated):** DR would be dispatched a limited number of hours during the year. NYISO may only call upon DR for ~50 hours in a year. The energy savings can be estimated based on the *average* demand savings (not peak) expected over the hours called, times the number of hours the DR resource is expected to be called. This average reduction would be multiplied by an appropriately time-differentiated ACE.

[101] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BADA5E14E-9633-436E-8B1B-10DF4AB02913%7D.
[102] Ibid.

B.5.6 Energy Efficiency Example

Energy efficient lighting depicts a load-reducing DER where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology. The parameter assumptions, and methodology used to develop those assumptions, developed using the NY TRM or PSEG Long Island specific values developed by the third party evaluation contractor.[103]

B.5.6.1 *Example System Description*

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting with an estimated utilization of 3,013 hours/year.[104] The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a load reducing because it decreases the customers' energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of an indoor, office-setting lighting system assumes that the coincidence factor is calculated during operational hours when the load reduction due to this lighting technology is expected to occur at the time of the system peak, as well as the during the transmission and distribution peaks.

B.5.6.2 *Benefit Parameters*

The benefit parameters described here were developed using guidance from the NY TRM.

Table B-20. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	1.0
DistCoincidenceFactor	1.0
∆Energy (time-differentiated)	~7 am to ~7 pm weekdays

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 1.0 under the assumption that the system peak occurs while standard office lighting systems are operating.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 1.0 under the assumption that the transmission system peak occurs while standard office lighting system are operating.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 1.0 under the assumption that the distribution system peak occurs while standard office lighting systems are operating.
4. **∆Energy (time-differentiated):** This value is calculated using the lighting hours per year (3,013) as provided for General Office types[105] in the NY TRM, divided by the total hours in a year (8,760). This time period is subject to building operation, which is roughly between 7 am and 7

[103] New York State Technical Resource Manual (TRM)l: New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 9, Issued on August 30, 2021 – Lighting operating hour data is sourced from the 2008 California DEER Update study.
[104] Ibid.
[105] New York State Technical Resource Manual (TRM)l: New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 9, Issued on August 30, 2021 - pg. 667

pm, 5 days a week, 52 weeks a year. This would define the corresponding period for determining an average ACE that would be used to calculate the benefit.

B.6 Utility-Specific Assumptions

This section includes PSEG Long Island-specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section 7.3B.4. The discount rate is set by LIPA and reflects the PSEG Long Island cost of capital, which is included in Table B-21.

Table B-21. PSEG Long Island Weighted Average Cost of Capital

Regulated Rate of Return
5.66%

Source: LIPA

PSEG Long Island-specific system annual average loss data is shown in Table B-22.

Table B-22. PSEG Long Island Loss Data

System	Variable Loss Percent	Fixed Loss Percent
Energy	N/A	5.67%
Demand	N/A	7.19%

Source: PSEG Long Island Transmission & Distribution Group

PSEG Long Island-specific system-level marginal costs of service for the period of 2022 through 2041 are presented below in Table B-23. The avoided carbon costs are incremental to the carbon coefficient embedded in the avoided marginal energy costs.

Table B-23. PSEG Long Island System Average Marginal Costs of Service

Year	Marginal Energy Cost $/kWh	Marginal Capacity Cost $/kW-Year	Avoided Cost of Carbon $/kWh Saved
2023	0.0414	23.55	0.02741
2024	0.0327	73.48	0.02741
2025	0.0295	68.68	0.02741
2026	0.0273	11.04	0.02741
2027	0.0272	16.92	0.02741
2028	0.0252	7.02	0.02741
2029	0.0254	13.14	0.02741
2030	0.0255	10.61	0.02741
2031	0.0263	11.99	0.02741
2032	0.0276	14.60	0.02741
2033	0.0291	14.77	0.02741

2034	0.0299	35.47	0.02741
2035	0.0291	41.01	0.02741
2036	0.0296	69.67	0.02741
2037	0.0311	98.34	0.02741
2038	0.0325	133.73	0.02741
2039	0.0338	173.02	0.02741
2040	0.0352	206.89	0.02741
2041	0.0359	235.22	0.02741
2042	0.0373	235.27	0.02741

Source: PSEG Long Island Utility 2.0 Filing, July 2022

Appendix C. LIPA and PSEG Long Island Structure

As the owner of the system, Long Island Power Authority (LIPA) has the means to raise capital and plays an extensive oversight role. Oversight is bolstered by New York Department of Public Service (DPS), the New York State utility regulatory authority that provides a due diligence and advisory role to LIPA regarding retail rates and the content and direction of the Utility 2.0 programs.

C.1 Long Island Power Authority

LIPA is a New York Public Authority that owns the electric T&D system on Long Island, New York. LIPA provides electric service to approximately 1.1 million customers in Nassau and Suffolk Counties and on the Rockaway Peninsula in Queens on Long Island. LIPA acquired responsibility for electric services on Long Island in 1998. At that time, LIPA acquired the electric T&D assets of Long Island Lighting Company (LILCO), KeySpan Corporation acquired LILCO's natural gas distributions assets, and LILCO's electric generating assets on Long Island. Exhibit I-1 provides an overview of the service territory. LIPA does not provide natural gas service or own any on-island generating assets.

LIPA as the owner of the utility plant retains the ultimate authority and control over the assets comprising the T&D System and as such has continuing oversight responsibilities and obligations with respect to the operation and maintenance of the T&D System, under the direction of the LIPA Board of Trustees. LIPA must obtain approval from the New York State Comptroller's Office for contracts in excess of $50,000. LIPA is also subject to the State Administrative Procedure Act, the Public Authorities Law, the State Finance Law, and various New York State Executive Orders.

C.2 LIPA Board of Trustees

LIPA is governed by a Board of Trustees (LIPA Board) consisting of nine members appointed by the Governor, the President of the Senate, and the Speaker of the Assembly. The LIPA Board approves the electric charges and budgets and has policy making, oversight and regulatory obligations for the Long Island T&D system.

C.3 PSEG Long Island (Service Provider)

PSEG Long Island is a wholly owned subsidiary of PSE&G headquartered in Newark, New Jersey. PSEG Long Island is fully dedicated to LIPA's operations and provides operations, maintenance, and related contract services for the T&D system, including:

- T&D operations to include electric transmission, distribution, engineering, system planning, and load serving activities for the safe and reliable operation and maintenance of the T&D system
- Capital planning development and execution of approved annual capital budget
- Management of rates, tariffs, and load forecasting functions, including performance of system revenue requirement
- Planning, deployment, and oversight of EE programs
- Management of all financial systems and reporting related to T&D operation
- Legal and regulatory related to T&D operation
- Energy markets
- Contract administration for LIPA owned or contracted generation assets
- Community and governmental relations related to T&D operation

- Performance measurement and reporting
- Treasury related to T&D operation
- Customer care, billing, and collections

The costs of operating and maintaining the Authority's T&D system incurred by PSEG Long Island are paid by the Authority. PSEG Long Island is paid a management fee and may earn incentives related to specified performance metrics outlined in the Operation Services Agreement. The structure is symmetrical where PSEG Long Island can earn an upward incentive and can, under certain circumstances, be assessed a penalty against the fixed component of the Management Services Fee.

The Amended & Restated Operating Services Agreement has a term of 12 years expiring on December 31, 2025, with a provision allowing for an 8-year extension.

In its role as Service Provider, PSEG Long Island is the face to the customer of the LIPA system with responsibility for all external branding, customer, and public communications.

The operating business is divided between the PSEG Long Island ManageCo that contains the senior management personnel and ServeCo that contains the balance of the employees. By design, the ManageCo is in place as long as PSEG Long Island remains in the role of Service Provider, while the ServeCo is directed by the ManageCo, would remain in place to support a successor Service Provider.

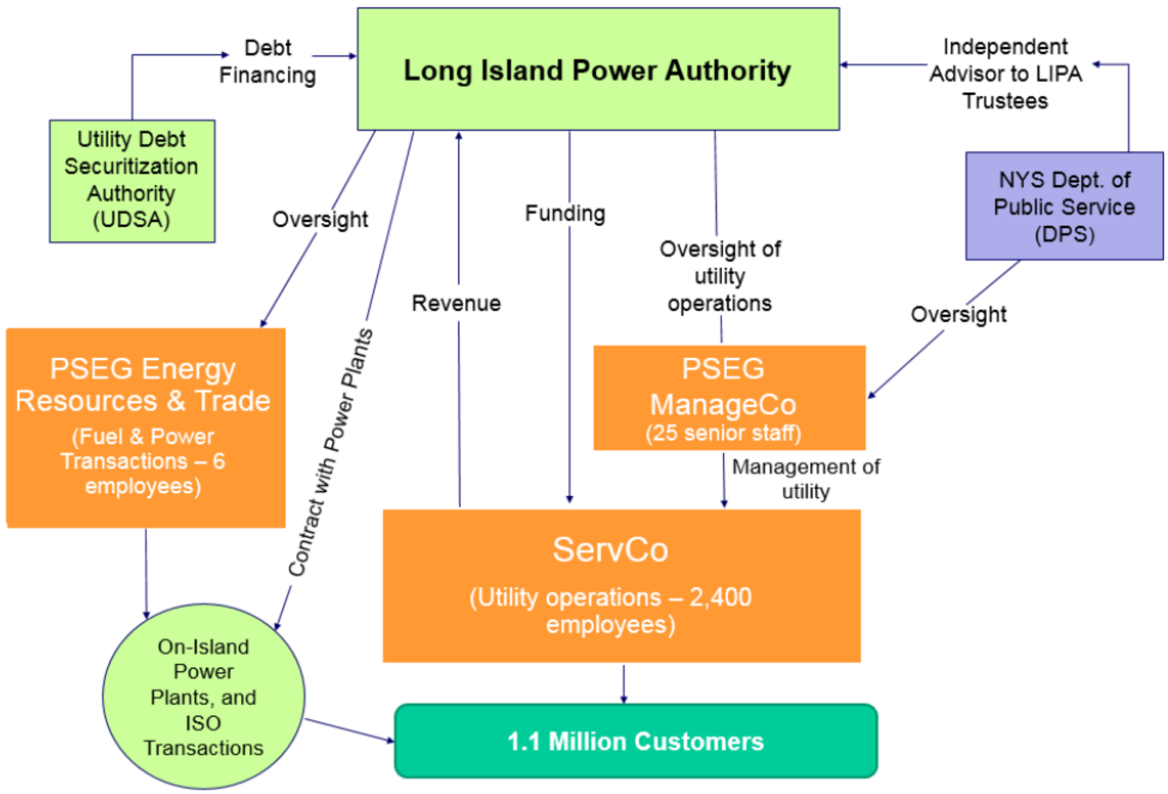
C.4 New York DPS

New York DPS, as the state utility regulator and implementing agency for REV, plays a vital advisory role with respect to PSEG Long Island's annual Utility 2.0 Plan review. The amended LIPA Reform Act provides for LIPA to submit its annual Utility 2.0 Plan to the New York DPS for review. Public Service Law §§3-b(3)(a) and (g), authorizes New York DPS to review and make recommendations to LIPA with respect to rates and charges, including those related to energy efficiency and renewable energy programs, and more specifically, to review and make recommendation with respect to any proposed plan submitted by LIPA or its Service Provider related to implementation of such plans.

Consistent with the direction set out in the Amended Operations Services Agreement, PSEG Long Island actively engages with New York DPS in the development of each year's plan update, seeking input throughout to foster alignment in terms of the direction of the plan across LIPA, New York DPS, and PSEG Long Island. Each year the findings and recommendations provided by New York DPS is a critical step to the advancement of the program.

C.5 LIPA's Public-Private Partnership Structure

Figure C-1. LIPA's Public-Private Partnership Structure



Risks Managed by the Parties

Ultimately, LIPA owns all risks of the Utility: those managed by PSEG Long Island as service provider and those that are managed by LIPA.

Managed by LIPA:

- Strategic direction of the organization, electric rates, and budgets
- Risk management – ultimately responsible to protect the value of the system
- System ownership – ultimately responsible for the condition of the system
- Cash management – including issuance and management of debt to fund capital expenditures
- Long-term contracts – execute long-term power supply contracts
- Grant eligibility – qualify for and comply with federal and state grants

Managed by the Service Provider:

- Customer and Brand Reputation – face of the Utility
- Electrical System reliability and service standards within Operations Services Agreement metrics
- Customer Experience and Satisfaction within Operations Services Agreement metrics
- EE and DG within Operations Services Agreement metrics
- Administers Power Supply and Clean Energy Standard Procurements

Appendix D. Acronyms and Abbreviations

ADMS	Advanced Distribution Management System
AGCC	Avoided Generation Capacity Cost
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
BCA	Benefit-Cost Analysis
BEV	Battery Electric Vehicle
BTM	Behind-the-Meter
Btu	British thermal unit
C&I	Commercial and Industrial
CAPEX	Capital Expenditure
CEP	Commercial Efficiency Program
CJWG	Climate Justice Working Group
Climate Act	Climate Leadership and Community Protection Act
CO_2	Carbon Dioxide
CRM	Customer Relationship Management
CS-MR	Customer-Side Make-Ready
CSR	Customer Service Representative
CSRP	Commercial System Relief Program
CVR	Conservation Voltage Reduction
DAC	Disadvantaged Community
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management System
DG	Distributed Generation
DLC	Direct Load Control
DLM	Dynamic Load Management
DLRP	Distribution Load Relief Program
DPS	Department of Public Service
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSP	Distributed System Platform
e-bus	Electric Bus

EE	Energy Efficiency
EEBEDR	Energy Efficiency, Beneficial Electrification and Demand Response
EEP	Energy Efficient Products
EFS	Energy Finance Solutions
ESCO	Energy Service Company
ESS	Energy Storage System
ETR	Estimated Time of Restoration
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FTE	Full-Time Equivalent
GHG	Greenhouse Gas
GIS	Geographic Information System
HEM	Home Energy Management
HPwES	Home Performance with ENERGY STAR
HVAC	Heating, Ventilation, and Air Conditioning
IOAP	Interconnection Online Application Portal
IT	Information Technology
JU	Joint Utilities
KPI	Key Performance Indicator
kV	Kilovolt
KVAR	Kilowatt and Reactive Power
kW	Kilowatt
kWh	Kilowatt-Hour
LBMP	Location-Based Marginal Pricing
LED	Light-Emitting Diode
LILCO	Long Island Lighting Company
LIPA	Long Island Power Authority
LMI	Low-to-Moderate Income
LSRV	Locational System Relief Value
m	Meter
MDHD	Medium-Duty Heavy-Duty
MDMS	Meter Data Management System
MMBtu	Million British Thermal Units (Btu)
MOU	Memorandum of Understanding
MVA	Mega Volt-Amp

MVAr	Mega Volt-Amp Reactive
MW	Megawatt
MWh	Megawatt-Hour
NPV	Net Present Value
NWA	Non-Wires Alternatives
NWS	Non-Wires Solution(s)
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OMS	Outage Management System
OSHA	Occupational Safety and Health Administration
PAC	Program Administrator Cost
PHEV	Plug-in Hybrid Electric Vehicle
PM	Project Management
PMO	Program Management Office
PPE	Personal Protection Equipment
PSEG	Public Service Enterprise Group Incorporated
PV	Photovoltaics
QA/QC	Quality Assurance/Quality Control
RCS	Remote Connect Switch
REAP	Residential Energy Affordability Partnership
REC	Renewable Energy Credit
REV	Reforming the Energy Vision
RFI	Request for Information
RFP	Request for Proposal
RIM	Ratepayer Impact Measure
SaaS	Software as a Service
SAFE	Safer Affordable Fuel Efficient
SCADA	Supervisory Control and Data Acquisition
SCT	Societal Cost Test
STS	Suffolk Transportation Services
T&D	Transmission and Distribution
TBtu	Trillion British thermal units
TOU	Time of Use
UCT	Utility Cost Test

UoF	Utility of the Future
US	United States
US-MR	Utility-Side Make-Ready
Utility 2.0 Plan	Utility 2.0 Long Range Plan
V2G	Vehicle-to-Grid
VAR	Volts-Amp-Reactive
VDER	Value of Distributed Energy Resources
VVO	Volt-VAR Optimization
ZEV	Zero-Emission Vehicle