New York Prize Stage 1

Feasibility Assessment for the

Long Island Community Microgrid Project

Final Report

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Notice

Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

AMI	Automated Metering Infrastructure
DER	Distributed Energy Resources
DR	Demand Response
EE	Energy Efficiency
ES	Energy Storage
FIT	Feed-In Tariff
IEc	Industrial Economics, Incorporated
IT	Information Technology
JEDI	Jobs and Economic Development Indicator (NREL)
LBMP	Location Bus Marginal Price
LICMP	Long Island Community Microgrid Project
LIPA	Long Island Power Authority
MC^2	Monitoring, Communications, and Control
MESA	Modular Energy Storage Architecture
MW	Megawatt
MWh	Megawatt-Hour
NREL	National Renewable Energy Laboratory
PPA	Power Purchase Agreement
PV	Photovoltaic
RFI	Request for Information
SAM	System Advisor Model (NREL)
SCADA	Supervisory Control and Data Acquisition
SCWA	Suffolk County Water Authority
SEEDS	SunEdison revenue-grade monitoring platform
SGSGSIP	Smart Grid Small Generator Standardized Interconnection Procedures
SIWG	Smart Inverter Working Group
SoC	State of Charge (of battery in energy storage system)
T&D	Transmission and Distribution
UCAP	Unforced Capacity

Summary

The bulk of this report was written in 2015 and submitted for NYSERDA review, including for NYSERDA's independent economic evaluation, accordingly. In the first half of 2016, however, a number of circumstances changed that could impact the Long Island Community Microgrid Project (LICMP) in scope, etc. Changed circumstances include the fact that PSEG Long Island (PSEG LI) has conducted a Request for Offer (RFO) process for resources that could fulfill some of the distributed energy resources (DER) requirements specified by the LICMP. Additionally, RFO proposals, if selected, could result in transmission requirements that reduce or eliminate the avoided transmission investments that have been contemplated in this feasibility report. Further, SunEdison, one of the major FIT applicants for solar PV projects within the LICMP, has filed for bankruptcy and those projects might be terminated as a consequence. Notwithstanding these changed circumstances, the Clean Coalition believes that the LICMP remains the most comprehensive Community Microgrid project in the United States, and the integration of the LICMP resources, regardless of procurement and ownership outcomes, provides an unparalleled opportunity to establish a new approach for designing and operating electric grids of the future.

Utilizing very high levels of locally generated solar electricity and other DER, the LICMP was analyzed as a new approach to designing and operating electric grids. Covering thousands of utility customers and located in the grid-constrained East End of Long Island, the LICMP analysis is based on nearly 50% of the LICMP grid-area electric power requirements being sourced from local solar generation. Importantly, the LICMP will greatly enhance resilience by providing indefinite renewables-driven backup power for critical community facilities, while potentially setting the stage to avoid hundreds of millions of dollars in transmission investments that otherwise would definitely be required to deliver power to the East End of Long Island. The result is an analysis that optimizes a local energy system combining local solar generation; energy storage; load control; and robust monitoring, communications, and control capabilities.

Developed in partnership with PSEG Long Island (PSEG LI) and Long Island Power Authority (LIPA), Suffolk County Water Authority (SCWA), and the Springs Fire District, the LICMP analysis is based on the following features:

- 15 megawatts (MW) of new solar photovoltaic generation, including 5 MW higher penetration than would be possible without the microgrid systems or grid upgrades.
- 5 MW/25 megawatt-hour (MWh) energy storage facility plus three smaller energy storage facilities.
- State of the art monitoring, communications, and control system.
- Coverage of over 40,000 residents—including thousands of residential and commercial utility and water customers—within the Community Microgrid.
- Provision of indefinite renewables-driven backup power for multiple critical loads, including a fire station with ambulance services and two water pumping and filtration stations that provision a significant amount of water to the area.
- Deliver normal operating benefits through utility-scale peak shaving.
- Demonstrate robust Community Microgrid capabilities over a substation grid area, which is the basic building block of an electric grid and can be easily proliferated throughout the utility service territory and replicated by other utilities across New York and around the world.
- Showcase how to design and operate electric grids with unparalleled levels of local renewables and other DER, while optimizing resilience.

The many benefits of the LICMP analysis include:

- Unparalleled penetration of local renewable energy with a concomitant reduced dependence on centralized, non-renewable power and local, oil-fueled peak generation facilities.
- Advancement of NY REV goals for achieving clean, resilient, affordable energy generation.
- Peak power demand reduction of over 8 MW, including 6 MW from new microgrid investment.
- A total of $38 million in avoided local transmission upgrade value, including $28 million from added microgrid investment, and potential for $300 million in avoided transmission upgrades if the LICMP is replicated throughout the region.
- Independent BCA net present value benefits of over $4 million from new microgrid investment.
- Over $32 million in wages and other economic value during the construction phase of the LICMP, with millions more under ongoing operations.
- Shift in wholesale power purchases from daily peak pricing periods to off-peak periods, realizing net savings in energy purchases of $2.5 million by 2022 and more than $500,000 annually thereafter.
- $334,000 per day of avoided local outage value for the community served by the LICMP circuits during regional outage events.
- Immediate and ongoing savings that result in lower electric rates for all PSEG LI utility customers.

The LICMP will provide renewables-based grid services to an area that includes thousands of utility customers with high vulnerability to severe North Atlantic storms. The LICMP showcases how to manage grid services locally during grid outages and across dynamic seasonal variations, including those caused by a doubling of the population during the summer. In addition to the SCWA and fire district properties, other critical facilities that could be incorporated include the local airport and additional emergency response facilities.

Community Microgrids are far more extensive than a typical microgrid, which only serves a single location with behind-the-meter resources. A key feature of a Community Microgrid is the ability to serve thousands of customers with local renewable energy while achieving economies-of-scale and providing renewables-driven power backup to critical facilities and services during grid outages. The LICMP covers 3,343 utility accounts across a single substation grid area. The substation-level nature of the LICMP ensures that its design can be readily extended across utility service territories and replicated by other utilities.

Project Objectives

The specific objectives of the LICMP are to:

- Leverage DER assets—primarily solar; energy storage; and monitoring, communications, and control—to improve the reliability, resilience, and security of the local electric distribution grid while reducing local and system peaks.
- Provide local power backup for the identified critical facilities and other prioritized loads (to be determined).
- Optimize the 5 MW/25 MWh battery across cost and energy, utilizing both the local solar and import from transmission at night for energy price arbitrage.
- Optimize smaller energy storage facilities for ongoing power backup to critical facilities in that case that grid outages occur along the feeder circuits.

- Maximize the interconnection and use of local solar generation, integrating up to 15 MW (dc) into the two feeders on Bank 4 of the substation.
- Use advanced load management techniques to reduce and shift loads as needed to match the local generation and storage assets on an ongoing basis as well as during outages.
- Minimize the use of existing local diesel generators (e.g. during summer peaks).

Project Description

The Clean Coalition's LICMP utility partners, PSEG LI and LIPA, chose the East Hampton GT substation in the South Fork of Long Island as the LICMP target grid area. This substation consists of two distribution feeder banks: Bank 3, with four existing feeders, serving a peak load over 20 MW; and Bank 4, with two existing feeders, serving a peak load approaching 15 MW. Peak demand times in this substation occur in the early evening, ranging from 5-7 PM depending on the season. To satisfy the peaks in the area, the East Hampton GT substation also utilizes 6 MW of distillate fuel diesel generators (3 generators with a capacity of 2 MW each).

The LICMP will initially serve the two feeders in Bank 4. The primary energy storage solution, a 5 MW/25 MWh battery, will be interconnected on the low voltage side of the East Hampton GT substation. During the day, the 15 MW of installed solar will provide power to the grid while the energy storage smooths power output and shaves peak energy usage. Advanced inverters, associated with all of the LICMP solar and energy storage deployments, will be used to provide voltage support at the substation and at all points of interconnection along the feeders.

The local solar generation and energy storage peak shaving will avoid major upgrades to the transmission infrastructure and reduce the need to dispatch the local oil-fired units in the area. During non-peak periods, when demand is lower, the solar generation can be used to charge the batteries or dispatched to the system—a choice that can based on the price of power and other economic factors. The batteries can also be used to absorb excess energy from the bulk system as needed. At night, the energy storage can be charged from the bulk system.

This report defines all the key variables—the specific loads, critical load amounts, targeted PV output, and energy storage capacity—that comprise the LICMP. In addition, key use cases have been described and charted to demonstrate operational feasibility. This document also includes economic analyses of the LICMP's financial feasibility.

To illustrate the expected minimum and maximum ranges, the four seasons help identify extremes across the variables of solar generation, loads/peaks, and required critical load reserves. For example, the LICMP will manage and optimize maximum solar output vs. minimum loads, such as noon during a spring weekend, while accommodating the variances between weekday and weekend load profiles. Optimizations also incorporate load history, weather forecast, load forecast, and cost of energy from the solar and the normal grid energy mix (energy imported from transmission into the LICMP).

The project incorporates the hourly, daily (weekday vs. weekend), and seasonal variations to the load profiles. Metered data (15 minute or hourly) is available for these loads by customer type. When detailed meter data is not available, data from an industrial control system like Supervisory Control and Data Acquisition (SCADA) can be used to estimate the daily load profiles at the service transformers as a group.

The basic layout of major components will support both normal operations and two emergency operating modes: feeder outage and transmission outage. In addition, the system is designed to accommodate normal communications and response times, as well as conditions of down communication to the central controller (e.g. stand-alone mode). Black start functions are also supported.

Challenges Faced During Feasibility

- Uncertainty around ownership of the large energy storage system has caused tension in LICMP considerations as there are a variety of potential owners, including LIPA, PSEG LI, or a third-party proposer via the recent PSEG LI RFO. The ownership scenario can be addressed as the LICMP and the RFO evolve. Ownership questions answered after the LICMP proves to be technically and economically viable can apply to the many projects that follow (importantly, within the next 15 years, there is a projected need for over 150 MW of additional peak generation capacity in the East Hampton region; at least ten times what is anticipated from the LICMP).

- The Town of East Hampton has stated that their goal is to achieve 100% renewable energy. However, the current environment in the town includes restrictions in siting solar PV and other DER. Reluctance by the Town is based on environmental concerns such as preserving green-space and aesthetic issues regarding the appearance of solar PV on commercial-scale rooftops and parking lots/structures. The Clean Coalition has engaged the former Town of East Hampton Planning Director, who oversaw the creation of existing general plans and permitting rules, and feels well positioned to gain community support for smaller solar projects and the LICMP, which helps achieve the Town's renewables goals and provides much needed resilience for the community.

Regulatory Changes Required for a Successful Community Microgrid

The key regulatory change that is required is essentially a change in stance so that operating utilities are encouraged to own DER assets in the Research, Development, and Demonstration (RD&D) pilot stage of the LICMP. To date, policymakers in New York have been posturing that incumbent utilities should not be allowed to own assets in the DER future, but until the DER technologies are deployed in pilot scale to determine their operating possibilities, it is critical that operating utilities are incentivized to truly test the operational possibilities of DER.

Recommendations

The most important recommendation is that all parties, including policymakers and utilities, focus on getting the LICMP deployed in order to establish it as an unparalleled RD&D opportunity for investigating the operating potential of the grid of the future.

Conclusion

The purpose of New York Prize projects is to challenge the conventional ways of thinking and provide new solutions to old problems and constraints. The LICMP represents a new approach for designing and operating the electric grid, and the LICMP is staged to provide the pathway forward to a DER future across New York. It is imperative that all parties align to ensure that all parties are motivated to make the LICMP a reality.

1 Description of Microgrid Capabilities

The Clean Coalition has developed the capabilities and functional requirements of the LICMP in close collaboration with the utility. In addition, the Clean Coalition published a Request for Information (RFI) document to key potential solution providers in order to validate certain capabilities and requirements. As a result, some of the descriptions below include summaries of, or specific feedback from, the RFI Respondents.

1.1 Minimum Required Capabilities

1. Must optimize the combination of local renewable energy, energy storage, energy imported from transmission, and local diesel generators such that the renewable energy and energy storage are combined to reduce both the local diesel generation and the amount of energy imported from transmission, primarily by reducing peaks. The optimized clean power resources shall minimize environmental impacts as measured by total percentage of energy covered by carbon-free energy generation.

    a. The RFI respondents all have experience integrating DER, monitoring grid and resource status, and deploying the DER in optimum fashion. The most critical factor is for the utility to define the business rules that prioritize the actions the controller must take during various states of operation to ensure reliable operation while maximizing the value of the DER.

2. Must satisfy the backup power requirements for the three physically separated critical facilities based on the load requirements provided in Critical Facility Loads (Tier 1 Loads) and the backup power generation profile provided in Distributed Energy Resource (DER) Portfolio.

    a. The configuration proposed includes enough PV and energy storage to run the defined critical loads for at least one week, and likely perpetually, before needing to utilize backup diesel generators. Table 5 through Table 7 in Critical Facilities: Optimal PV & Energy Storage Profiles summarize the PV plus energy storage solution proposed for each critical facility, in order to satisfy the backup power requirements. The tables indicate the amounts of combined PV + energy storage at each critical facility site that will provide backup power. The LICMP also provides backup power via the central energy storage located at the substation, fed by the 15 MW of total PV across the entire system. Both the onsite PV + energy storage and the central energy storage + system wide PV provide an uninterruptible supply of backup power to the critical facilities. If for any reason both of these resources are unavailable, each critical facility site also currently has diesel generators as an additional backup power source.
    b. Please also refer to Appendix G: Energy Storage Sizing Calculations for Critical Loads, which provides details for the backup power use cases for the critical facilities. The use cases assume an initial 50% state of charge (SoC) with a minimum SoC level of 10% mandated at the central energy storage. Relying on just the 25 MWh central energy storage capacity without any PV re-charging, the model shows that the critical loads can run more than three days in winter and almost two days in summer. Assuming consecutive cloudy days, there is still more than enough energy from the PV to re-charge the energy storage as well as run other loads during daylight hours to provide ongoing backup power to the critical loads during an extended regional outage. On sunny days, less load would need to be shed during the outage.

3. Must be able to form an intentional island such that the identified critical facilities are provided 100% of load requirements during any grid outage. Any non-critical loads can be shed.
    a. The proposed configuration has islanded operation as a central requirement and capability. All the critical load sites already have this capability using diesel generators; the controllers simply have to change the loading order of generation sources—using solar and energy storage first, for example—and management of appropriate DER parameters, e.g. energy storage SoC. The configuration assumes that the utility is responsible for either shedding non-critical loads or notifying the critical loads to isolate (depending upon configuration architecture details).
4. Must provide on-site power in both grid-connected and islanded mode, with an uninterruptible fuel supply or minimum of one week of fuel supply on-site for the critical facilities.
    a. In addition to backup power provided by the PV + energy storage, each critical facility already uses diesel generators, and each critical facility site will have a fuel supply sufficient to run the onsite diesel generators for at least one week as a backup to the onsite PV + energy storage supply.
5. Use an optimal amount of PV and Energy Storage at each of the three critical facilities, given the amount of critical load that is required for each site and the overall architecture of the system.
    a. The architecture chosen is used in Figure 1 with backup modes shown in Figure 3 and Figure 4.
    b. Three architectures were considered that meet the criteria and are shown in Appendix J: All Project Configurations Considered. All RFI respondents can support all three, but the majority favor distributing energy storage among all critical loads as shown in Figure 1.
6. Must be able to separate critical facility locations automatically from grid on loss of utility source and restore to grid after normal power is restored.
    a. The controller respondents can all perform this action but will require inputs from the utility operations group to gracefully manage disconnect and reconnecting. All critical facility sites currently manage this function independently.
7. Must plan on intermittent renewable resources that will be utilized toward overall generation capacity only if paired with proper generation and/or energy storage that will allow 24 hours per day and 7 days per week utilization of the power produced by these resources.
    a. The proposed configuration of 15 MW of PV and 5 MW/25 MWh of ES has this capability, as explained in the responses to question 2 above.
8. Must comply with manufacturer's requirements for scheduled maintenance intervals for all generation
    a. The microgrid controllers normally only require software updates and replacement of any failed components. Some controller vendors also have redundant architectures with failure detection and automatic cutover to redundant circuits for improved reliability.
    b. The owners of the DER will comply with all required operations and maintenance requirements, such as keeping the solar panels clean. Larger system operators have remote monitoring and can dispatch technicians if maintenance is needed.

9. Generation must be able to follow the load while maintaining the voltage and frequency when running parallel connected to grid. Generation also needs to follow system load and maintain system voltage within ANSI c84-1 standards when islanded.
    a. All respondents state this capability explicitly and have experience complying with this requirement.
10. Include an active network control system that optimizes demand, supply and other network operation functions within the Community Microgrid.
    a. All respondents state this capability explicitly and have experience complying with this requirement.
11. Include a means for standardized two-way communications and control between the Community Microgrid controller, the local distribution utility, and external/3rd party systems through automated, seamless integration.
    a. All respondents have experience with setting up secure communications systems for their products, both wired and wireless, for monitoring, controls, and alarms. If available options from the utility do not provide sufficient bandwidth or the latency is too long, the respondents set up their own secure networks. In addition, key solutions will comply with industry-emerging standards such as MESA, and the Smart Inverter Working Group (SIWG) communications framework.
12. Must diagram the architecture(s) that fulfills the overall solution, including system interoperability and required interactions/interfaces with the local distribution utility and external/3rd party systems. In terms of interactions/interfaces, state what is proprietary versus standardized. Include processes to secure control/communication systems from cyber-intrusions/disruptions and protect the privacy of sensitive data.
    a. The RFI respondents have submitted their own diagrams, some of which are generic but satisfy all the requirements of the proposed configurations and others which are modifications of the proposed architectures, showing how their equipment fits in.
13. Provide high-level descriptions of data and control flows that is not necessarily a detailed design, but rather identification of states, how issues are handled, and key assumptions that must be true in order to achieve success.
    a. The types of data that are required basically consist of status (configurations, equipment, readiness, grid presence/absence, etc.), parametric data (SoC, outputs, measurements, etc.), commands, and acknowledgements. It is desirable to have continuous communications among the controllers, but these systems are designed to run autonomously based upon local inputs and state sequencing in case of communications breakdowns.
    b. System functions during normal parallel mode are described in Normal Operations and Figure 1. Examples of how the DER interacts with load are given in Case 1: Bank 4 Normal Operations, Worst Case of Min PV, Max Load, Case 2: Bank 4 Normal Operations, Max PV, Max Load in July, and Case 3: Bank 4 Normal Operations, Min PV, Min Load in July.
    c. See the section Feeder Outage and Figure 2 and Figure 3 for the sequence of events that transpire when a feeder goes down and a critical load must continue operating in islanded mode. Also see Case 4: Bridgehampton Pump Station, Sustained Islanded Operation in July

for an example of how the pumping station could be powered indefinitely from PV during five worst case solar days.

d. See the section on Transmission Outage and Figure 4 to see how the grid is configured to share DER to power critical and priority loads during a transmission outage event. Case 5: Loss of Transmission shows how the substation ES has more than enough capacity to power the critical loads during a sustained loss of transmission and could allow the powering of selected priority loads during that time.

14. Provide power to the identified critical facilities and all customers connected directly to the Community Microgrid. Diversity should apply to customer type (e.g. residential, small commercial, industrial, institutional, etc.) and overall demand and load profile.

    a. The utility has selected the critical facilities for this project that provide maximum community benefit. The respondents' proposals are neutral as to type of load: they simply need reasonable estimates of anticipated load profiles for their optimizations. The major advantage of the Community Microgrid architecture is captured by this requirement because the utility control of the non-critical load shedding gives the utility great flexibility in providing service during regional outages to as many diverse customers as possible, based upon the utility's assessment of each outage's potential duration. The resources that are in daily use for load balancing locally are instantly re-purposed in the event of an outage to support the community and maximize power reliability.

15. Demonstrate that critical facilities and generation are resilient to the forces of nature that are typical to and pose the highest risk to the location/facilities in the community grid. Describe how the microgrid can remain resilient to disruption caused by such phenomenon and for what duration of time.

    a. The solar PV and energy storage resources at each critical facility will be installed using industry-accepted solutions for protecting those resources from the anticipated forces of nature. For example, the solar PV arrays will use multiple inverters as a redundancy so that partial operation is still possible even with damaged components. All solar arrays are tested to be compliant with IEC 61215 for resistance to hail damage and wind loading. The energy storage will be located in storm and flood protected housings. In addition, the Community Microgrid’s distributed and resilient architecture provides backup power to critical loads in the case of outages, whether due to forces of nature or otherwise, and whether outage issues are caused by the centralized transmission grid or the local distribution grid. The centralized energy storage is anticipated to be located close to the utility substation, also installed in storm and flood protected housing. The 15 MW of solar PV across the entire Community Microgrid is distributed to multiple sites. This geographically dispersed solution, in addition to using multiple inverters at each solar PV site, adds further redundancy to protect against the forces of nature. This type of resiliency is controlled by the utility in the physical design and placement of the structures and housings for the equipment and for the communication systems. Many proposed sites are under control of the utility or the critical facilities and will provide protection consistent with existing critical infrastructure equipment at each site.

16. Specify the data and methodology used to determine the estimated peak demand reduction (kW savings) and annual kWh savings attributable to the Solution proposed.

   a. Historical operational data for the 6 MW of diesel engines at the East Hampton GT was provided by the utility, and an analysis was done for weekday and weekend hourly operation by month as shown in Appendix F: Existing Diesel Generator Usage Profile. PSEG LI also provided historical and projected LBMP hourly pricing as described in 3.2 Commercial Viability – Value Proposition. Savings were calculated from these values.

17. Provide black-start capability.

   a. Within the Community Microgrid, the controllers are designed to manage black start while islanded or to gracefully switch among generation resources per optimization algorithms. The controllers will also be under the supervision of the utility to assist in controlling black start for the entire substation area.

18. Provide information on elements of the Solution that affect the community (both positive and negative) including, but not limited to, associated reductions in GHG emissions, waste streams and management, job creation potential, and community disruption.

   a. Community benefits from deployment of 15MW of PV and 5 MW/25 MWh of ES include:
      - Reduced carbon emissions by more than 7 million pounds annually.
      - 278 job years created by construction and ongoing operations of the 15 MW of solar.
      - 30 job years created by the construction of the 5 MW of storage.
   b. There are no negative impacts from the LICMP on the community, though concerns have been raised from residents about siting of large solar projects. It is anticipated that by scaling the projects to smaller sizes, they will be amenable to jurisdictional authorities and their constituents.
   c. The LICMP has no relevant waste stream impacts. It is compliant with state standards for end of life.

19. Specific to Energy Storage technology: the type of energy storage technology being proposed and all relevant performance characteristics, warranties, and restrictions.

   a. The utility has not made final determination of the energy storage technology or technologies to be used. A formal RFP process will be utilized to select the final energy storage solution located at the substation. Note that with the current state of technology, the planned long duration of 5 hours @ 5 MW for the centralized energy storage at the substation favors flow batteries. For the distributed energy storage located at the critical load sites, the technology will probably differ depending upon the duration and the desired services (backup, peak shaving, energy arbitrage, …) or ancillary services (DR, voltage support, …) planned for the storage by the utility or the site owner. Lithium Ion or Lead Acid are the likely candidates given the solution profile.

1.2 Preferred Microgrid Capabilities

20. Integrate and demonstrate operation of advanced, innovative technologies in electric system design and operations, including, but not limited to, technologies that enable customer interaction with the grid such as, Microgrid Logic Controllers, Smart Grid Technologies, Smart Meters, Distribution Automation, Energy Storage; include an active network control system that optimizes demand, supply and other network operations functions within the microgrid.

   a. The Monitoring, Communications & Control system is the critical smart grid solution and centerpiece—or brain—that will optimize the Community Microgrid system components. Energy storage will be used daily for peak management and for backup of critical services when needed during outages.

21. Include Energy Efficiency (EE) and other Demand Response (DR) options to minimize new microgrid generation requirements.

    a. The LICMP will try to leverage existing utility DR program across the LICMP grid area, including at the critical facility sites. A previously proposed DR rollout would have tripled DR enrollment to 100 MW in 2015/2016, representing 20% of the load, and although the proposal was rejected, it is indicative of the DR potential within the context of the LICMP. In addition, as optimal the DR program will be expanded to also leverage the critical facility onsite energy storage as part of the overall demand management solution. This type of advanced DR is in the list of DER that the control systems will have access to in order to plan and manage the deployment of assets during both normal operation and emergency situations. Note that one controller respondent is already certified to utilize DR in both California and New York markets. LICMP will utilize the existing utility EE program for the area.

22. Specific to any proposed Demand Response solutions, include a description of the markets, such as one-to-four family homes, multifamily buildings, small commercial (e.g., retail stores, restaurants), large commercial (e.g., office buildings, industrial) and government or institutional (e.g., hospitals, hotels, schools, colleges), and the applicable Solution and technologies to be directed at each selected market or customer segment. In addition, the solution should illustrate the marketing and sales strategies that will be employed to capture the selected market or customer segment and to deliver the demand reductions.

    a. In April 2016, LIPA Trustees approved a demand response tariff that is consistent with state directives and that became effective on April 1, 2016. Third-party aggregators will do most of the marketing.

23. Address installation, operations and maintenance, and communications for the electric system to which interconnection is planned (e.g., underground networks, overhead loops, radial overhead systems).

    a. The LICMP leverages the existing electric distribution grid. By design, this project requires no new underground networks, overhead loops, radial overhead systems, etc. This is a key in helping bring scale and cost-effective solutions to communities and utilities. One critical new grid technology this project will add is new advanced switching gear that will enable the utility to shed non-critical loads during outages. In terms of the communication solutions, all the RFI respondents have experience working with utilities, integrating their communications infrastructure with existing utility systems, and/or installing new communications infrastructure such as wireless networks, as needed.

24. Coordinate with the Reforming the Energy Vision (REV) work to provide a platform for the delivery of innovative services to the end use customers.

    a. PSEG LI and LIPA, in their roles as both the LICMP owner and operator, and as the regional utility, are actively establishing this project as a platform for the delivery of new reliability and power quality services to customers. The increased visibility, control, and grid accommodation capability enabled by LICMP will also support integration of additional customer and third party DER facilities, and the management of these facilities to optimize performance.

b. The planning and updating process of this report are part of coordinating the goals of this project to ensure they align with the NY REV and with NYSERDA's guidance.

25. Take account of a comprehensive cost/benefit analysis that includes, but is not limited to, the community, utility and developer’s perspective.

    a. A cost/benefit analysis performed by the Clean Coalition, and a separate standardized BCA by the independent evaluator have been included as appendices in this report,, which include details about the following:

    - Independent BCA estimated $334,000 per day of avoided local outage value for the community during regional outage events.
    - Over $32 million in local wages and other economic value from project construction; and additional local economic stimulation ongoing.
    - Savings for all electric utility customers from the start and ongoing.
    - The LICMP will potentially avoid a total of $38 million in new, local transmission capacity, including $28 million from added microgrid investment, resulting in an immediate net cost benefit for all electric utility ratepayers.
    - The energy storage will allow the utility to shift wholesale power purchases from daily peak pricing periods to off-peak periods, realizing net savings in energy purchases of $2.5 million by 2022 and more than $500,000 annually thereafter.
    - The combination of utility storage and microgrid control systems support 50% higher penetration levels of distributed PV generation on circuits, increasing the siting and development opportunities for developers responding to utility power purchase agreement (PPA) offers or interest in additional customer sited generation.

26. Leverage private capital to the maximum extent possible as measured by total private investment in the project and the ratio of public to private dollars invested in the project.

    a. The utility will own the monitoring, communications, and control assets; and potentially the energy storage assets as well The majority of the required LICMP investment, however, is in the PV generation, which will be owned privately but managed by the utility if required by the architecture and deployment scheme, and the utility is anticipated to procure a bulk of the PV using a FIT.

27. Involve clean power supply sources that minimize environmental impacts, including local renewable resources, as measured by total percentage of community load covered by carbon-free energy generation.

    a. At the assumed LICMP achievement of 15 MW (DC) of carbon-free PV generation, the LICMP would provide about 45% (20k MWh) of the total annual energy (44k MWH) used in Bank 4 of the substation, and with the planned 25 MWh of energy storage, the need to run the diesel peaking generators in the summer would be eliminated.

28. Demonstrate tangible community benefits, including but not limited to, (e.g. jobs created, number of customers served, number of buildings affected, scale of energy efficiency retrofits, etc.).

a. In addition to general ratepayer savings, tangible local community benefits of the LICMP include but are not limited to the following:

- 278 job years created by construction and ongoing operations of the 15 MW of solar.
- 30 job years created by the construction of the 5 MW of storage.
- 3,243 utility customers and 21,084 water customers served.
- 6,600 – to nearly 20,000 residents served by the fire station, depending on the time of year.
- About 100 commercial and industrial facilities.

2 Preliminary Technical Design Costs and Configuration

Note: Estimation of the costs and benefits at this stage of the NY prize competition (Feasibility) is likely to be accurate within +/- 30%. The emphasis at this stage of analysis is on establishing a reasonable basis for competing for funding for a detailed, audit-grade engineering and business case analysis at a subsequent stage of the NY Prize Community Grid Competition.

2.1 Proposed Microgrid Infrastructure and Operations

1. Provide a simplified equipment layout diagram and a simplified one-line diagram of the proposed microgrid, include location of the distributed energy resources (DER) and utility interconnection points. Identify new and existing infrastructure that will a part of the microgrid.
    a. Figure 1: Operation of Microgrid Assets in Normal Operating Mode provides a diagram with all the major assets and illustrates the connectivity of the ES and PV resources in front of the meter at the critical facility sites with switches that are important for routing connections to DER during both normal and emergency conditions. Existing diesel generators at the critical loads and the substation will remain in place. The new equipment consists of the large PV (both on site with the critical loads as well as nearby), ES (both at each critical load site as well as at the substation), and switches along with the communications and controller equipment. The controller equipment directs the switches to either share the DER using the distribution grid or to isolate the critical loads and continue operations with local resources during a local feeder outage.
2. Provide a brief narrative describing how the proposed microgrid will operate under normal and emergency conditions. Include description of normal and emergency operations.
    a. During normal operation, Figure 1 shows how DER in front of the meter are directly connected to the distribution grid. During a local feeder outage Figure 3 shows how switches reconfigure the DER to island the critical loads and maintain ongoing operation utilizing local DER. During a transmission outage, Figure 4 shows how the DER and the central ES are configured to provide ongoing power by shedding non critical loads and using the existing distribution grid wires to share generation and ES resources among the remaining loads. Existing diesel generators will remain in place to act as backups to the new DER.

2.2 Load Characterization

3. Fully describe the electrical and thermal loads served by the microgrid when operating in islanded and parallel modes: Peak KW, Average KW, annual/monthly/weekly KWh, annual/monthly/weekly BTU (consumed and recovered) and identify the location of the electrical loads on the simplified equipment layout and one-line diagrams.
    a. The loads at the critical facilities are all electrical; there is no thermal generation. The critical loads are the Tier 1 loads in Figure 1.
    b. Table 1: Summary Critical Load Statistics for normal parallel operation is derived from billing data for the critical loads over one year. During emergency operation, the plan is to reduce the daily load by about 20%. In addition, the pumping stations would shift their load

profiles by 4 to 6 hours in order to move their maximum loads into the daylight hours to coincide with the solar generation peak, as shown in Figure 2.

Table 1: Summary Critical Load Statistics

	Peak kW	Average kWh/hr	Annual kWh	Monthly kWh	Weekly kWh
Bridgehampton Pumping Station	178.1	85.92	752,665	62,722	14,474
Oak View Pumping Station	117.0	37.55	328,979	27,415	6,327
Springs Fire Station	27.5	9.37	82,120	6843	1579

4. Provide hourly load profile of the loads included in the microgrid and identify the source of the data. If hourly loads are not available, best alternative information shall be provided.
    a. Load profiles for four months of available metered data for the pumping stations are shown organized for weekday and weekend profiles in Figure 9 and Figure 10 for the Bridgehampton pumping station. Figure 11 and Figure 12 show the comparable data for the Oak View station.
    b. There is no metered data for the fire station. The best assumption is that its profile would resemble the SCADA for the feeders that serve that area as shown in Figure 7 and Figure 8. However, the 24-hour nature of the fire station's operation would indicate a possible flattening of the profile.

5. Provide a written description of the sizing of the loads to be served by the microgrid including a description of any redundancy opportunities (ex: n-1) to account for equipment downtime.
    a. Energy Storage + PV is provided onsite as the primary backup for each critical facility. See Solution Profile section.
    b. Redundancy for serving these loads comes from the existing diesel generators currently serving each site that will become backups to the energy storage and PV primary sources during islanded operation.

2.3 Distributed Energy Resources Characterization

6. Provide the following information regarding Distributed Energy Resources (DER) and thermal generation resources that are a part of the microgrid: (i) Type (DG, CHP, PV, boiler, solar water heater etc.), (ii) rating (KW/BTU), and, (iii) Fuel (gas, oil etc.).
    a. PV for this project has two locations: onsite with the critical loads and "nearby" so that relatively short wire runs can connect them to the critical loads for emergency support. A list of potential sites that includes existing proposed projects is found in Table 3 that includes their locations and sizes.

b. Energy Storage for the project has two components. Local ES would be used to continue operations at the critical loads during feeder outages as shown in Figure 3.
c. As discussed in Energy Storage, a 5 MW/ 25 MWh ES system has been analyzed by PSEG LI to replace the existing diesel generators during normal peak loads. This resource is utilized during transmission outages as shown in Figure 4.

7. If new DER or other thermal generation resources are a part of the microgrid, provide a written description of the approximate location and space available. Identify the DERs on the simplified equipment layout and one-line diagrams. Differentiate between new and existing resources.
    a. The onsite and nearby PV for the critical loads are shown in Figure 1. The existing resources are the diesel generators at the critical loads and substation. These will remain as backups to the proposed DER. New resources in that figure are the PV, ES, switches, and the control system at the facilities and the substation.
    b. The pumping stations have plenty of open land for new ground-based PV and space for ES near the existing diesel generators. The fire station has room for ES near its existing pumping station and for roof-top PV.
8. Provide a written description of the adequacy of the DERs and thermal generation resources to continuously meet electrical and thermal demand in the microgrid.
    a. Sizing of the PV for continuous operation of the critical loads is shown in Table 5: Minimum Solar Size Estimates for 24 hours of Operation in December.
    b. Sizing of the ES is summarized in Table 7: Minimum Energy Storage Sizing Estimates Based Upon Reserved SoC. The analysis is covered in the paragraphs that precede that table which also shows assumptions based upon the amount of PV available to recharge the ES while serving load. The selected ES capacities are based upon maintaining a 50% state of charge prior to the emergency and having a P10 (minimal) solar resource available for recharging.
9. Describe how resilient the DERs and thermal generation resources will be to the forces of nature (severe weather) that are typical to and pose the highest risk to their operation (example, reduced or zero output due to snow cover over PV panels, potential flooding of low lying areas, etc.)?
    a. The new equipment will be housed in enclosures that meet state, local, and utilty environmental requirements. High reliability leased communication lines meeting the requirements of the utility will connect the monitoring, communications, and control system for normal and backup operations. Facility level control equipment will be housed inside existing structures that currently house control and communications equipment.
    b. The worst-case resource limitation is snow coverage of the solar panels. For all critical loads, existing diesel generators can be operated until snow could be cleared. The backup use cases show that with proper energy storage sizing and contingency reserves with SoC management, at least 24 hours of operation can be achieved for the critical loads in backup mode. In addition, the modeling shows that for worst-case minimal solar output days in July, continuous operation of critical loads from minimal solar is achievable.
10. Provide a description of the fuel sources for DER. Describe how many days of continuous operation of the microgrid can be achieved with current fuel storage capability? If additional fuel storage is required, provide a written description of needs required for this.

a. Energy storage & PV: Calculations have been done for both Central energy storage and Distributed energy storage configurations as noted above for energy storage operation without PV and continuous (ongoing daily) operation with PV. See Figure 21 for examples of 5-day operation in backup mode with minimal solar generation for the Bridgehampton pumping station. Figure 22 shows that for just the critical loads, the proposed large ES at the substation could easily power the critical loads from PV during a transmission outage, thus allowing some Tier 2 loads to be served as the solar forecast allows.
b. Diesel fuel storage: With load management, there is sufficient existing capacity to run the generators for about two days of continuous load. There is sufficient space at all locations to add additional fuel storage if needed. It is normally not desirable to store large amounts of diesel fuel for long periods because the fuel can lose its efficacy when stored for long periods.

11. Provide a written description of the capability of DERs including, but not limited to the following capabilities; black start, load-following, part-load operation, maintain voltage, maintain frequency, capability to ride-through voltage and frequency events in islanded mode, capability to meet interconnection standards in grid-connected mode.

PSEG LI Smart Grid Small Generator Standardized Interconnection Procedures (SGSGSIP) requires inverters compliant with California Rule 21 (section A.5). All of the features listed in the question (and more), as well as interconnection compliance, are covered in the specification. In addition, see the

a. PSEG RFP for South Fork Energy Storage sections B 10.1, 10.2, and 10.3 for relevant inverter requirements.

2.4 Electrical and Thermal Infrastructure Characterization

12. Provide a high-level written description of the electrical infrastructure (feeders, lines, relays, breakers, switches, current and potential transformers (CTs and PTs) and thermal infrastructure (steam, hot water, cold water pipes) that are a part of the microgrid. Identify the electrical and thermal infrastructure on the simplified equipment layout (with approximate routing) and one-line diagrams (electrical only). Differentiate between new, updated and existing infrastructure.

    a. As noted in Operational States all DER and switches added for this project are in front of the meter where the utility can control them directly. The new DER consist of large PV, some local at each critical load and some “nearby” that can be switched in as needed. ES is provided at each critical load for operation during local feeder outages. PSEG LI has already planned to install a 5 MW/ 25 MWh ES system to use instead of diesel generators for summer peaks. Existing diesel generators at each critical load and at the substation will remain in place as secondary backups. The layout for normal operation is shown in Figure 1, with all new DER connected to the feeders; see Normal Operations for more details. For a local feeder outage, Figure 3 shows how each critical load can isolate from the feeder and operate from the local ES with the switches configured to recharge the ES from local and nearby PV; see Feeder Outage for more details. For a transmission outage, Figure 4 shows how the switches shed non critical loads and share the central ES on the existing feeder with the critical loads; see Transmission Outage for more details.

13. Describe how resilient the electrical and thermal infrastructure will be to the forces of nature that are typical to and pose the highest risk to the location/facilities. Describe how the microgrid can remain

resilient to disruption caused by such phenomenon and for what duration of time. Discuss the impact of severe weather on the electrical and thermal infrastructure.

a. Resilience requirements will be consistent with those required by PSEG LI in the

b. PSEG RFP for South Fork Energy Storage: B4.1. Storm-Resistant Location and Facilities. Power Production resources and interconnection facilities must be designed to withstand 130 mph winds and to elevate equipment to accommodate updated 1-in-500 year flood zones. The PV panels are IEC 61215 compliant. SunEdison has several large systems in New Jersey, which all survived Hurricane Sandy without damage and continued operation after the storm with no servicing.

14. Provide a written description of how the microgrid will be interconnected to the grid. Will there be multiple points of interconnection with the grid. What additional investments in utility infrastructure may be required to allow the proposed MG to separate and isolate from the utility grid. Provide a written description of the basic protection mechanism within the microgrid boundary.

    a. The basic connections are described in Figure 1 and the section Normal Operations. All new DER and switches are connected in front of the meter so that the utility can control therm. Each critical load has its own interconnection point and its own set of resources, such as existing diesel generators, behind the meter. The facility control points are connected to the utility's existing SCADA monitoring and control system as described in question 15, below. The facility level controller is designed to manage its resources locally for ongoing operations in the event of a loss of communications with the substation level controller.
    b. The new grid assets allowing the Community Microgrid to separate and isolate are the switches, which are configured to either isolate the load or to transfer power from neighboring PV over to the load during backup operation. The sequencing and safety requirements for operation in islanded mode while using grid assets will have to be defined by the utility since this is a new architecture.
    c. Modeling done for the backup operation in the Cases section of Appendix A shows that continuous operation from solar DER is possible if SoC of the energy storage is managed properly using load management techniques.

2.5 Microgrid and Building Controls Characterization

15. Provide a high-level written description of the microgrid control architecture and how it interacts with DER controls and Building Energy Management Systems (BEMS), if applicable. Identify the locations of microgrid and building controls on the simplified equipment layout diagram. Differentiate between new and existing controls.

    a. The control structure is based upon a new centralized main controller at the substation with new satellite controllers at each critical load, as shown in Figure 1. The satellite controllers will be connected to the existing BEMS for the fire station and to the existing SCADA system at the pumping stations. The satellite controllers will monitor and report information to the central controller and respond to its commands. Once configured and operating properly, the satellite controllers are capable of autonomous operation in the event of a grid outage.

16. Provide a brief written description of the services that could be provided by the microgrid controls including, but not limited to the following:

- Automatically connecting to and disconnecting from the grid: Requirement in SGSGSIP sec. III and V.D, V.G; standard feature.
- Load shedding schemes: RFI respondents anticipate utility control and notification of operating mode change; standard feature.
- Black start and load addition: Requirement in SF RFP sec. B11.1; standard feature.
- Performing economic dispatch and load following: Requirement in SF RFP sec. B11.2; standard feature.
- Demand response: RFI respondents anticipate utility control and notification of amount to anticipate in optimization calculations.
    - For the fire station: handled through BEMS.
    - For the pumping station, coordinated through SCWA SCADA control system.
- Storage optimization: Per RFI respondents, this capability is inherent in controller but must be driven by utility business rules.
- Maintaining frequency and voltage: Requirement in SF RFP sec. B11.2; standard feature.
- PV observability and controllability; forecasting: Observability requirements are in SGSGSIP sec. III. Forecasting is assumed as utility provided input to microgrid controller optimization; standard feature with the controllers. This is also a standard requirement on large PV systems directly controlled by the utility.
- Coordination of protection settings: Requirement in SGSGSIP sec. III and V.D, V.G; standard feature.
- Selling energy and ancillary services: interpreted by central controller for each DER.
- Data logging features (inherent in the design of microgrid controllers): standard feature
- How resilient are the microgrid and building controls? Discuss the impact of severe weather on the microgrid and building controls: Controls will be housed inside of buildings which are rated to withstand severe weather events.

2.6 Information Technology (IT)/Telecommunications Infrastructure Characterization

17. Provide a high-level written description of the IT/Telecommunications Infrastructure (wide area networks, access point, ethernet switch, cables etc.) and protocols. Identify the IT and telecommunications infrastructure on the simplified equipment layout diagram. Differentiate between new and existing infrastructure.

    a. The telecommunications infrastructure uses a validated, robust hard-wired connection. Communications protocols are based upon SCADA protocols, and PSEG LI requires that the interface gear be made available to them or even purchased by them and then set up and validated in their own facilities before deployment. See

    b. PSEG RFP for South Fork Energy Storage section B 10.4 for more details.

18. Provide a written brief description of communications within the microgrid and between the microgrid and the utility. Can the microgrid operate when there is a loss in communications with the utility? How resilient are the IT and telecommunications infrastructure?

a. The microgrid controllers are designed to work in concert during normal operations where the grid assets are shared and to manage their own local resources when islanded, even with no communications from the Facility level controllers to the Substation level.
b. PSEG LI requires leased hard-wired telecommunications lines with which they have had good experience with reliability and resilience.

3 Assessment of Microgrid's Commercial and Financial Feasibility

3.1 Commercial Viability – Customers

Ownership and operation of the LICMP infrastructure will be determined as various decisions are made over the coming months, but local solar is expected to be purchased from third-party owned facilities; mostly via the existing FIT. Both critical and priority loads as defined in the LICMP design will be supported during islanded (emergency) operation. The utility may elect to offer new products and tariffs reflecting local and/or renewable content or prioritized service to customers during islanded emergency operation.

1. Identify the number of individuals affected by/associated with critical loads should these loads go unserved (e.g. in a storm event with no microgrid).
    a. 40,000
    b. Detail: Two SCWA pumping stations and one local fire station are the identified critical loads served by the proposed Community Microgrid project. In the event of a regional or local power outage the microgrid would maintain service to the critical (Tier 1) loads. In addition, possible electrical service can be provided to prioritized (Tier 2) customers as analysis of resources allows.
    c. The pumping stations supply water to SCWA Distribution Area 23, which has 21,084 customer accounts associated with a local population of approximately 40,000 based on US Census data. The two pumping stations supply 11% of the total summertime water supply for Distribution Area 23 but are networked to the entire Distribution Area and would be capable of supplying all or nearly all of the water emergency requirements for all the residents throughout the Distribution Area when outdoor water use would be curtailed in the summer or demand is seasonally reduced.
    d. The Springs Fire District serves 6,600 residents in the winter and more than double that amount in the summer.

2. Identify any direct/paid services generated by microgrid operation, such as ancillary services, or indirect benefits, such as improved operation, to the utility or NYISO? If yes, what are they?
    a. The 15 MW of independently owned PV included in the LICMP is contracted to provide 100% of its generation to the local utility, providing energy (over 40% of the annual energy consumed in the Community Microgrid area), local generating capacity, and backup power to support critical and priority services in the event of an outage.
    b. The 5 MW/25 MWh storage capacity included in the LICMP will help meet local peak capacity needs in addition to daily energy arbitrage; backup power to critical loads; and potential power quality, load balancing, and voltage services supporting the integration of high levels of local PV, increasing the circuit hosting capacity for PV by 5 MW.
    c. Utility control and coordination of the 20 MW of generation and storage capacity will offer opportunities to assess and demonstrate the use of distributed resources in providing ancillary services to NYISO, however this is not the focus of the proposed development as the value of these services is small in comparison to the primary functions.

3. Identify each of the microgrid's customers expected to purchase services from the microgrid.

   a. The utility is the direct customer. SCWA and Springs Fire Department are the primary local critical load customers of the utility provisioned by the LICMP. The utility can also offer improved reliability services in the form of backup power "as available" to additional priority load customers on the substation bank served by the LICMP.

4. Identify other microgrid stakeholders; what customers will be indirectly affected (positively or negatively) by the microgrid.
   a. All PSEG LI customers receive electric service from the utility, and the energy and services produced by the LICMP will contribute to the utility's resource supply on behalf of its customers. While the energy will serve local loads, utility customers will continue to receive power from the utility and will remain on regular tariffs. As proposed in this report, the LICMP will contribute $29-38 million of avoided new transmission capacity value, in addition to contracted energy, resulting in net cost benefit to all PSEG LI utility ratepayers. The local generation capacity provided by the LICMP PV and storage facilities will also reduce NYISO capacity charges by $6 million through 2022, and by more than $1 million annually thereafter. In addition, the energy storage facilities will allow the utility to shift wholesale power purchases from daily peak pricing periods to off peak periods, realizing net savings in energy purchases of $2.5 million by 2022 and more than $500,000 annually thereafter. These savings will be reflected in electric rates for all PSEG LI customers.
   b. Local residents will benefit from improved resilience and reliability of the Community Microgrid area, including backup power provided to critical water and fire services plus other prioritized loads.
   c. Local and regional residents will benefit from improved air quality associated with avoided operation of the 6 MW diesel peak generation facility and its emissions.
   d. Under full LICMP implementation, any local DER owner may benefit from offering energy services to the utility operated LICMP.

5. Describe the relationship between the microgrid owner and the purchaser of the power.
   a. Many ownership decisions are still being made, but it is anticipated that for LICMP energy and services owned by third-parties will be purchased by the utility under long term PPA and service contracts. The utility will likely need to own communication and control systems and any grid infrastructure improvements.

6. Indicate which party/customers will purchase electricity during normal operation. During islanded operation? If these entities are different, describe why.
   a. The utility will purchase 100% of electricity during normal and islanded operation, and will in turn sell the electricity to its customers under existing tariffs undifferentiated from other wholesale energy supplies.

7. What are the planned or executed contractual agreements with critical and non-critical load purchasers?
   a. The utility's load customers will continue under existing tariffs. The utility will prioritize service to critical and priority load customers during outages, and may develop and offer new optional priority service tariff options to customers.

   b. The utility may elect to offer new products and tariffs reflecting local and/or renewable content or prioritized service during emergency operation.

8. How does the applicant plan to solicit and register customers (i.e. purchasers of electricity) to be part of their project?
   a. The LICMP represents a new approach to designing and operating the electric grid. With the exception of the critical facilities that are LICMP partners, all other parties simply benefit from the economic, environmental, and security benefits that the LICMP provides. The utility will utilize LICMP for all its existing customers in the designated service area during normal operations and prioritize service to critical and priority load customers that have already been identified during emergency operation.

9. Are there any other energy commodities (such as steam, hot water, chilled water) that the microgrid will provide to customers?
   a. No additional energy commodities are planned at this time. The LICMP will provide electric energy services only. The future addition of CHP is possible, and can be incorporated as opportunities arise, but is not planned in this initial deployment.

3.2 Commercial Viability – Value Proposition

1. What benefits and costs will the community realize by the construction and operation of this project?
   a. Demonstrating the ability to cost effectively integrate high levels of local renewables supports local, state, and national goals addressing secure and sustainable energy supplies and emissions.
   b. The reliable provision of power to critical water and fire department services enhances safety and security in the event of extended outages—this is very important when needed, however the value is difficult to assess due to the rarity of such events.
   c. NREL Jobs & Economic Development Impact analysis for the regional community indicate that development of 15 MW of PV will result in 200 job years of employment, $15.5 million in wages, and a total economic output value of $28.4 million. These figures do not include any value associated with the manufacture of equipment in the state or region.
   d. Following construction, ongoing operations will yield an additional $258,000 annually in local wages, totaling $5.2 million over the first 20 years of operational life.
   e. PV Site leasing at a rate of $10,000 per MW per year is anticipated to contribute an additional $150,000 annual income value to properties owners in the LICMP service area, totaling $3 million over the first 20 years of operational life.
   f. Development and installation of the proposed 5 MW/25 MWh of energy storage facilities is initially estimated to result in 30 total job years of employment, $2.3 million in salary and wages, and $4.1 million in total economic output value. These figures do not include any value associated with the manufacture of the storage systems or associated equipment in the state or region. Following construction, ongoing operations will yield and additional $86,000 annually in local wages, totaling $1.7 million over the first 20 years of operational life. These figures are preliminary and may vary substantially depending on the storage technology selected.

g. Utility work required for the interconnection of the generation and storage facilities is included in the employment and economic impact analysis for these facilities. Additional utility investment in grid modernization including communications and control systems has not yet been assessed, but may be anticipated to result in additional economic effects of the total LICMP project in the range of 5%.
h. Wages will result in additional public revenues from income taxes, sales taxes related to induced household spending, and reduced public benefits costs that are not included in the NREL analysis.
i. This project does not rely on investment from the community beyond that of the regional utility and independent energy providers. Net costs and benefits realized by the utility will be reflected in electric rates. The LICMP is anticipated to generate net positive value in avoided costs, but not at a level that will impact utility electric rates unless broadly implemented at scale.

2. How would installing this microgrid benefit the utility? (E.g. reduce congestion or defer upgrades)? What costs would the utility incur as a result of this project?
   a. As analyzed for this report, the LICMP will contribute $29 million of avoided new transmission capacity value, from the 5 MW/25 MWh of energy storage and 5 MW of additional PV integration, or $38 million if the full 15 MW of integrated PV is considered. Added to contracted energy, this results in a net cost benefit to all PSEG LI utility ratepayers. The local generation capacity provided by the LICMP PV and storage facilities will also reduce NYISO capacity charges by $6 million through 2022, and at a rate exceeding $1 million annually thereafter. In addition, the energy storage facilities will allow the utility to shift wholesale power purchases from daily peak pricing periods to off peak periods, realizing net savings in energy purchases of $2.5 million by 2022 and more than $500,000 annually thereafter. These savings will be reflected in lower electric rates for all PSEG LI utility customers.
   b. The utility will enter into long term PPAs in which the net present value is expected to be lower but may be higher than the projected or actual cost of conventional energy and reliability services over the same period, plus the cost of delivery of that power. LIPA has previously projected that a $70/MWh price differential for local generation was warranted and net beneficial to ratepayers where it contributed to avoid the South Fork Transmission Project. In addition, the utility may choose to implement or advance certain distribution system upgrades to accommodate delivery of LICMP energy to utility customer and critical loads.

3. Describe the proposed business model for this project. Include an analysis of strengths, weaknesses, opportunities and threats (SWOT) for the proposed business model.
   a. This is primarily a utility operated Community Microgrid based on PPA and energy storage service contracts with independent suppliers selected by RFP (and FIT). The utility maintains conventional backup power that will mitigate risk of non-performance in addition to contract terms.
      i. Strengths: The project contributes to meeting identified multi-megawatt capacity needs in this area at lower cost than conventional alternatives while providing a demonstration and testing opportunity that can be readily replicated to improve critical load service, emission reduction, and a variety of other benefits to utility

customers and residents. The Community Microgrid approach works within the existing utility relationships with customers and suppliers and does not require the development of new business models or tariffs.

ii. Weaknesses: Independent energy producers and storage suppliers are required to plan installations and compete for limited contracts with the utility, creating uncertainty and risk in the supplier market regarding the cost and value of participation; this may fail to attract sufficient participation to achieve goals, and may not achieve maximum cost effectiveness until replicated at scale.

iii. Opportunities:

1. Utility ownership of the communications and control systems, and the distribution grid itself, allows complete flexibility in the design and utilization of these resources without negotiating third-party contractual restrictions. This allows the utility to explore alternative modes of operation to test performance, experiment with offering additional service products, assess assumptions, and incorporate unanticipated opportunities and technical advances.
2. Based on Clean Coalition work in other states like California to achieve interconnection standards that allow for far higher penetrations of local renewables, independent renewable energy producers will be supported in offering at least 50% higher penetrations of distribution resources than would be practical without the use of Community Microgrid functionality, improving scale of facilities and utilization of available siting opportunities, resulting in lower costs and increased total local market potential.

iv. Threats: The business model incorporates long-term (20 year) power purchase commitments from local energy suppliers and utility investment in energy storage, interconnection facilities, and communications and control systems. These financial commitments and capital investments represent inflexible costs that marginally limit the ability of the utility to benefit from potentially lower market rates in the future were these to occur. The contracted local generation development and storage capacity will contribute to avoiding a major transmission upgrade investment, but not be sufficient in and of itself to avoid that investment. If either these projects or others in the total transmission alternative portfolio fail to occur, then the expected capacity will need to be replaced with substitute capacity in order to achieve the savings calculated from these transmission alternatives, and the costs of substitute capacity may reduce the expected savings.

4. Are there any characteristics of the site or technology (including, but not limited to, generation, storage, controls, information technology (IT), automated metering infrastructure (AMI), other, that make this project unique?
   a. The Community Microgrid Project approach, is unique in several respects relative to other microgrids:
      - LICMP utilizes the existing distribution system to coordinate the operation of components at multiple sites distributed across circuits connected to the same

substation bank, scaling the microgrid approach to the utility circuit and substation level.

- The monitoring, communication and control systems will demonstrate field application throughout multiple circuits across a substation bank.
- As analyzed, the 20 MW LICMP incorporates 15 MW of PV and 5 MW of large energy storage; plus smaller energy storage deployments to facilitate indefinite renewables-driven power backup to critical facilities.
- The LICMP is operated by the local utility, and will coordinate both utility owned assets and independently owned and operated assets under contract to the utility.
- This installation offers high levels of regional avoided infrastructure cost value in conjunction with operational value while also ensuring continuous islandable service to public critical loads.
- The business model does not require or rely upon customer subscription.
- The business model allows the utility to offer subscription to widely dispersed non-contiguous customers for various attributes, including local renewable content plus critical and priority load service during local and/or regional outages.

5. What makes this project replicable? Scalable?
   a. The Community Microgrid approach, including asset optimization and utility operation, is designed to be replicable across any substation, and scales the microgrid approach to the utility circuit and substation level. Local implementation reflects grid needs and DER development opportunities identified through the optimization approach to the design.
      i. A Community Microgrid in general, and the LICMP specifically, is operated by the local utility, allowing replication at substation scale throughout that utilities service territory under consistent policies, procedures, and staffing of a single program, providing a model that can be readily adopted by other utilities.
      ii. By coordinating non-contiguous resources dispersed along multiple circuits within a substation bank, additional resources can be incrementally incorporated as they become available anywhere in the existing utility circuits connected through the Community Microgrid/LICMP. This approach integrates the load of all electric customers and allows maximum development of local distributed energy resources.
      iii. By coordinating both utility owned assets and independently owned and operated assets, this approach allows development of microgrid resources to flexibly occur through multiple ownership and financing channels.
      iv. The business model does not require or rely upon customer subscription, and is not therefore limited by customer subscription.

6. What is the purpose and need for this project? Why is reliability/resiliency particularly important for this location? What types of disruptive phenomenon (weather, other) will the microgrid be designed for? Describe how the microgrid can remain resilient to disruption caused by such phenomenon and for what duration of time.

a. LICMP meets the need to serve critical loads – water supply and fire/ambulance facilities essential for the local population.
b. The Atlantic coast is subject to severe storms and flooding, and this region of Long Island is particularly susceptible. Electric power is currently dependent upon a single radial transmission route and cannot be cost effectively networked to alternate transmission service for improved reliability. Limited diesel generation backup power is available at the critical facilities, however resupply of fuel is subject to storm impact and restricted road options. Utility owned diesel peaker power facilities and distribution grid operations are not currently designed for islanded operation, and the utility is seeking to reduce reliance on fossil generation in general and diesel generation in particular.
c. The LICMP is designed to provide continuous and ongoing renewables-based backup power service to critical and priority loads during periods of local or regional outages, including hardened service to adjacent critical loads. PV sources are not dependent upon fuel supplies, energy storage compliments PV for 24 hour operation and can operate from any alternate available power source, and existing conventional peaker facilities may remain available as tertiary BUP.

7. Describe the project's overall value proposition to each of its identified customers and stakeholders, including, but not limited, the electricity purchaser, the community, the utility, the suppliers and partners, and NY State.
    a. **As analyzed, the utility**, as energy purchaser, will avoid more costly transmission capacity additions, retains long term fixed price energy PPAs, and the storage capacity to arbitrage TOD energy, while reducing use of local diesel peak generation.
    b. **As analyzed, the entire community** within the LIMCP grid area will realize improved reliability and critical load service, net ratepayer cost savings over conventional alternatives, and economic development benefits including investment and employment opportunities and associated public revenues, while realizing reduced emissions and achieving almost 50% of its annual energy consumption from clean local resources.
    c. **Suppliers and partners** will gain stable long-term contracts for services and experience with utility Community Microgrid development to reduce costs and replicate widely.
    d. **NY State** will realize a widely replicable model for efficient DER implementation and local grid optimization to enhance efficiency, reliability and streamlined deployment of cost effective distributed renewables, and a demonstration of Distribution Service Provider grid operation at community wide substation scale with high levels of DER as called for in New York's Reforming the Energy Vision initiative. This improves statewide energy security while replicating and scaling the community benefits statewide.

8. What added revenue streams, savings, and/or costs will this microgrid create for the purchaser of its power?
    a. Added revenue streams:
        - Utility contracted control of inverters and storage operation enables provision of ancillary services to the NYISO in addition to local power quality and operational optimization (DR, Reactive Power, Conservation Voltage…). This project will demonstrate the capacity to provision ancillary services to NYISO but does not plan

on utilizing this capacity to participate in the markets until replicated at a sufficient scale to be economically significant.

b. Savings:

- The local generation capacity, energy and services produced by the LICMP will contribute to the utility's resource supply and avoid alternate costs.
- The region is projected to have increasing load resulting in a load service capacity deficiency of 63 MW by 2022 that under a traditional central generation approach would require $300 in transmission investment based on transmission planning studies performed by LIPA. This new transmission may be avoided through the development of local resources at lower cost. LICMP resources will contribute to the total local capacity required to avoid the new transmission investment while also supplying local power in the event of a transmission interruption.
- The LICMP will incorporate 10 MW of PV already planned for these circuits, which will offer a 20% net qualifying capacity value against peak transmission load service, contributing 2MW to the total required peak transmission load reduction. This is valued at $9.5 million as a portion of the total avoided transmission fixed cost value.
- The storage facilities will support higher penetration of PV on the LICMP circuits, allowing a planned additional 5MW of PV, providing 1MW of transmission capacity offset, valued at $4.8 million as a portion of the total avoided fixed cost transmission value.
- As analyzed, the 5MW/25MWh LICMP storage facilities will directly contribute 5MW to peak transmission load reduction, valued at $23.8 million as a portion of the total avoided transmission fixed cost value.
- The storage facilities will also reduce NYISO capacity charges by $6 million through 2022, and by more than $1 million annually thereafter. Capacity charges are variable and escalate over time.
- The energy storage facilities will allow the utility to shift wholesale power purchases from daily peak pricing periods to off peak periods, realizing net savings in energy purchases of $2.5 million by 2022 and more than $500,000 annually thereafter. Energy peak pricing differentials are variable and have historically escalated over time.
- Together, the development of new local storage resources operating within the LICMP will contribute $32.3 million in avoided costs by 2022, and at least $1.5 million escalating annually thereafter.
- The proposed LICMP storage design as described above is anticipated to result in total net cost savings on the order of $10 million through 2022. Additional savings will accrue throughout the life of the equipment and contracts.

c. Costs:

- The total installed capital cost for 5MW/25MWh capacity battery systems over a 20-year period is on the order of $20 million.
- The operating costs for energy storage are included in the 30% round trip cost of use, including losses and facility operation. These costs are reflected in the modeled value

of daily energy arbitrage utilizing the available storage capacity for off peak power purchases to replace peak power purchases for a net savings on energy purchases.

- Capital costs associated with local distribution system communications modernization to accommodate planned PV, storage, and islanding for critical load service will be determined based upon final siting plans and operational requirements but are not anticipated to exceed $2 million for the scope of the planned installations.

9. How does the proposed project promote state policy objectives (e.g. NY REV, RPS)?

   a. The LICMP promotes and helps achieve specific REV 2030 targets:
      - 40% reduction in GHG emissions from 1990 levels by 2030, and 80% by 2050;
      - 50% generation of electricity from renewable energy sources by 2030;
      - Building a more resilient energy system;
      - Create new jobs and business opportunities;
      - Improve and build upon New York's existing infrastructure; and
      - Foster clean energy growth through the development of innovative Community Microgrids, which provide a scalable, "plug-and-play" approach to proving that local renewable energy combined with energy storage and other DER provide a cleaner and more reliable foundation for the modern grid.
   b. As analyzed, the LICMP will provide approximately 45% of total annual customer demand through local distributed renewable resources, demonstrating the ability of these resources to contribute substantially to New York's Renewable Energy targets.
   c. The project will also provide New York with a widely replicable model for efficient DER implementation and local grid optimization to enhance efficiency, reliability and streamlined deployment of cost effective distributed renewables.
   d. Operation of this Community Microgrid project will demonstrate REV's Distribution Service Provider grid operation at community wide substation scale with high levels of DER.
   e. The provision of continuous service to critical loads during emergency islanded operation, and "as available" service to other priority loads, maintains public services, health, and safety during emergencies.

10. How would this project promote new technology (including, but not limited to, generation, storage, controls, IT, AMI, other)? What are they?
    a. This project demonstrates the use of advanced inverter functionality, including voltage regulation, islanding capabilities, and real-time monitoring and control.
    b. This project provides the grid capabilities for effective use of AMI and further integration and valuation of customer-generation and services provided by DER.
    c. This project demonstrates the use of advanced MC^2 systems that optimize all the Community Microgrid assets based on forecasts, loads, and generation on a daily basis under normal operations, while enabling advanced switching, load shedding, and islanding to support both critical loads and prioritized loads under multiple emergency operation scenarios.
    d. This project demonstrates advanced load management techniques that shape loads to optimize the Community Microgrid's local generation and storage resources, including targeted load reductions and load shedding under multiple emergency situations.

e. This project promotes new developments in grid optimization planning approaches leading to more scalable, "plug-and-play" integration of distributed renewable generation, and energy storage

3.3 Commercial Viability – Project Team

1. Describe the current status and approach to securing support from local partners such as municipal government? Community groups? Residents?
    a. The Clean Coalition's key partners for the LICMP are the utilities (PSEG LI and LIPA) and the municipalities with authority over the critical facilities (SCWA and Springs Fire District). These partners are in place.
    b. As for solar partners, evaluation of the FIT applications is still in process and is happening in coordination with local permitting authorities.
    c. Beyond solar, other DER solution providers are being evaluated through a Request for Information (RFI) process that the Clean Coalition conducted for energy storage solutions and for monitoring, communications, and control systems. Responses for a multitude of viable DER proposals have been received and are being evaluated for selection.
    d. Additional municipalities, including the Town and Village of East Hampton have been engaged in dialog, and the Clean Coalition anticipates cooperation from them.
        i. The Village of East Hampton has been very supportive of the LICMP vision and is enthusiastic about the benefits that the LICMP will bring.
        ii. The town of East Hampton has a stated goal to rely on renewable energy for 100% of its electrical energy use. The LIMCP represents the best pathway for the Town to achieve its 100% renewables goal.
    e. Multiple community groups have learned of the LIMCP and want to provide support. The Clean Coalition looks forward to involving community partners at the appropriate time.

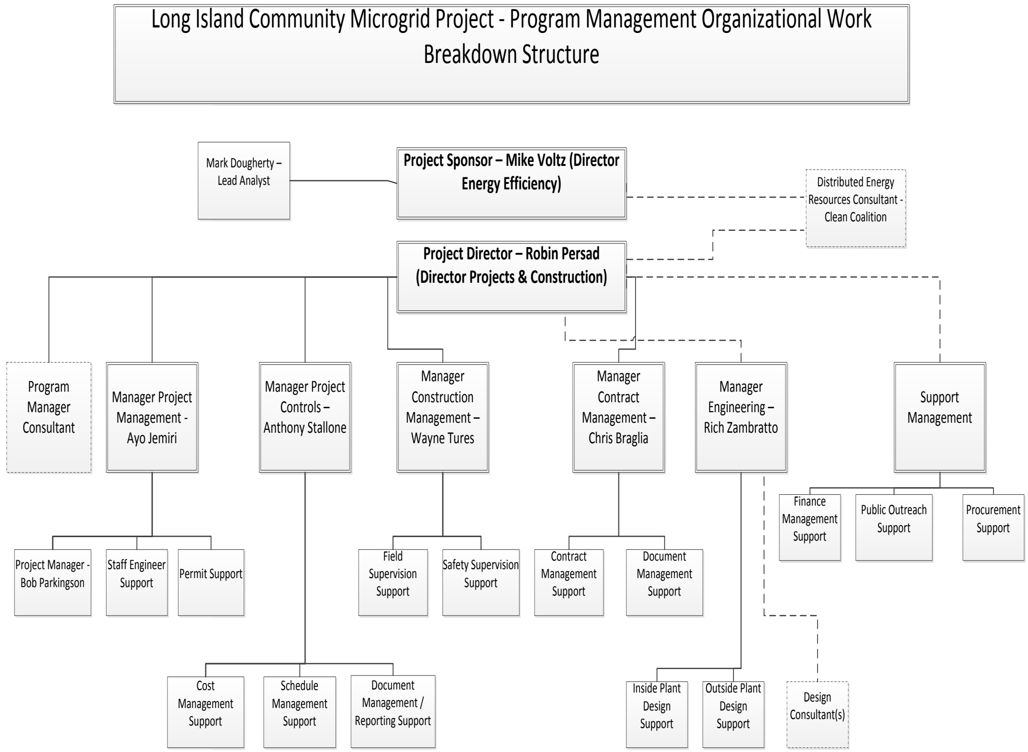
2. What role will each team member (including, but not limited to, applicant, microgrid owner, contractors, suppliers, partners) play in the development of the project? Construction? Operation?
    a. PSEG-LI is the grid operator, and at the very least, will oversee the design, interconnections, and operations of the LICMP. The utility will purchase energy from independently owned local PV generation facilities under established long-term contracts. PSEG-LI will acquire storage and control facilities from suppliers through a competitive procurement process including installation and maintenance. PSEG LI is partnering with critical load facility owners to ensure provision of sufficient energy during emergency islanded operation, including the installation of necessary equipment at or near the critical load sites – these are the SCWA pumping stations and Springs Fire Department. Energy suppliers and critical load customers will enter into separate agreements with the utility regarding their capabilities and needs to ensure adequate power supply through the utility during islanded operation.
    b. The Clean Coalition is providing the feasibility analysis, review of viable technology and technology vendors, and design for Stage 1, and will help lead the audit-grade technical and financial analysis during Stage 2.

3. Each team member brings specific skills to the project that will help ensure a successful result, satisfying both the nature of the single deployment but also ensuring that the solution can be

scaled and replicated readily. Accordingly, the PSEG LI team brings experience in grid design, operations, and reliability. As a complement, the Clean Coalition brings skills in designing systems and methodologies that achieve high penetrations of local renewables while supporting grid reliability and optimizing the financial results. Together, this team has the complement of skills to prove that high penetrations of solar PV supported by energy storage is a viable solution for the U.S. electric grid. The specific decisions impacted by each team member are as follows:

- Michael Voltz, PSEG LI Director of Energy Efficiency & Renewable Energy: all final Go/No Go decisions in all stages
- Mark Dougherty, PSEG LI Lead Analyst-QA/QC Compliance: all final decisions relative to quality compliance in all stages
- Robin Persad, PSEG LI Director of Project and Construction Management: provide leadership and direction at the project level for all decisions relative to the project management process and deliverables and final vendor selection in all stages
- Craig Lewis, Clean Coalition Executive Director, Principal Investigator: overall leadership and all decisions specific to the design of the LICMP in all stages
- Greg Thomson, Clean Coalitions Programs Director: contribution to decisions specific to the design of the LICMP during Stage 1: Feasibility Assessment
- Lisa Liquori, Clean Coalition Community Relations Manager: contribution to all decisions relative to community stakeholders in all stages
- Robert O'Hagan, Clean Coalition Program Engineer: contribution to all decisions relative to the DER optimization power flow modeling and DER portfolio design in all stages
- Kenneth Sahm White, Clean Coalition Economics & Policy Analysis Director: contribution to all decisions relative to the financial analysis in all stages

4. A more detailed team organizational structure for PSEG LI is provided below, with the Clean Coalition engaged as distributed energy resource specialists:



5. Are public/private partnerships used in this project? If yes, describe this relationship and why it will benefit the project.
    a. A public/private partnership is envisioned to the extent that LIPA (a public/municipal utility) and PSEG-LI will be operate the LICMP and will procure distributed energy resources, like local solar, from private parties; and the LICMP will directly benefit municipal entities like the SCWA and the Springs Fire Department through indefinite renewables-driven backup power in the case of grid outages.. Additional municipal facilities could become beneficiaries as the LICMP progresses into Stage 2.

6. Describe the financial strength of the applicant. If the applicant is not the eventual owner or project lead, describe the financial strength of those entities.
    a. The financial strength of the applicant is based on the utility partners: LIPA and PSEG LI. PSEG LI is a subsidiary of the Public Service Enterprise Group, a New Jersey-based publicly traded diversified energy company with annual revenues of $11 billion that operates the Long Island Power Authority's transmission and distribution system under a 12-year contract through 2026. PSEG LI serves 1.1 million customers in Nassau and Suffolk County, as well as Queens and the Rockaway Peninsula.

7. For identified project team members, including, but not limited to, applicant, microgrid owner, contractors, suppliers, partners, what are their qualifications and performance records?
    a. As for solar partners, LIPA has an active FIT program that has attracted initial applications for about 30 MW of solar capacity to the LICMP grid area; twice as much local solar capacity as is needed to meet the LICMP's overarching generation goal of 50% of total energy consumed within the LICMP grid area from local solar. Evaluation

of the FIT applications is still in process and is happening in coordination with local permitting authorities.

b. Beyond solar, other DER solution providers are being evaluated through a Request for Information (RFI) process that the Clean Coalition conducted for energy storage solutions and for MC² systems. Responses for a multitude of viable DER proposals have been received and are being evaluated for selection.
c. Ultimately, the utilities, assisted by the Clean Coalition, will use a required and official RFP process to evaluate and select the final solutions, including the energy storage and MC² systems. Evaluation of the FIT applications is still in process and is happening in coordination with local permitting authorities.

8. Are the contractors and suppliers identified? If yes, who are they, what services will each provide and what is the relationship to the applicant? If no, what types of team members will be required and what is the proposed approach to selecting and contracting?
    a. The hosting utility (PSEG LI) has released an RFP for local PV generation facilities to be incorporated into the LICMP, has received competitive offers in excess of the capacity required, and is currently completing final contracting. At least 10 MW will be procured, and an additional 5 MW will be incorporated upon confirmation of energy storage procurement. Final selection among the tendered offers has not been completed.
    b. The utility, assisted by Clean Coalition, will be developing an RFP and evaluating storage and control system suppliers necessary for LICMP implementation.

9. Are the project financiers or investors identified? If yes, who are they and what is their relationship to the applicant? If no, what is the proposed approach to securing proposed financing? Will other members of the project team contribute any financial resources?
    a. The LICMP grid investment will be utility capital improvements and ownership of the energy storage facilities is still being evaluated. Solution providers will identify financing plans as part of their responses to RFPs and other procurement approaches.

10. Are there legal and regulatory advisors on the team? If yes, please identify them and describe their qualifications. If no, what is the proposed approach to enlisting support in this subject area?
    a. Yes, PSEG LI is providing both legal and regulatory advisors to the project team as follows:

- PSEG Legal advisor: Jeff Greenblatt. Jeff Greenblatt is the Senior Counsel Regulatory for PSEG LI. Prior to joining PSEG LI, he was a senior associate in the Corporate Department at Cullen and Dykman LLP, a general practice law firm headquartered in New York. Mr. Greenblatt has spent over seven years in the utility industry, and has extensive experience with Public Service Law Article VII, New York's statutory framework for siting major utility transmission facilities. He also worked in-house at National Grid's offices as a secondee in the New York Regulatory Practice Group. Mr. Greenblatt received a B.A. in Political Science from the University of Michigan, and a J.D. from St. John's University School of Law. He has been admitted to the New York State Bar since April 2007.

- PSEG Regulatory Advisor: Mike Ennis. Mike Ennis is currently the Regulatory Compliance Manager for PSEG LI. Prior to that, he was the Manager of the Commercial

Efficiency group for PSEG LI. He has also held various positions within National Grid, Keyspan Energy, and LILCO, including Manager, Business Operations; Manager, Energy Technology; and Manager, Major Accounts. Mike has over 35 years of experience in the utility industry, providing business and energy efficiency solutions to commercial customers throughout Long Island. Mike received an engineering degree from the United States Merchant Marine Academy at Kings Point and a MBA from Dowling College. He is a Business Energy Professional as well as a Certified Sustainable Development Professional.

3.4 Commercial Viability – Creating and Delivering Value

1. How were the specific microgrid technologies chosen? Specifically discuss benefits and challenges of employing these technologies.
    a. PV and storage were chosen to provide reliable electric service to critical and priority loads for an unlimited period. These facilities can be located adjacent to critical loads in sufficient capacity to supply power in the event of either transmission or local distribution grid failure, and to do so without reliance on fuel delivery.
    b. PV generation profile reliably and substantially correspond with peak demand and transmission constraints, reducing or eliminating the use of local diesel generation, and providing reliable power independent of fuel supplies.
    c. Storage is required to meet 24/7 critical loads during islanding events in combination with PV, while providing additional daily services in normal operation to realize maximum value, including addressing partial misalignment between PV generation profiles and peak transmission constraints. Specific storage technologies will be evaluated in an RFP process to meet minimum islanding operational requirements while providing maximum overall cost effectiveness.
    d. This project features a large storage system located at the substation, to be used for peak management as well as for supporting the solar and critical/priority loads. The particular challenge is removing barriers in order to ensure that specific technologies can be piloted and thus proven, enabling grid modernization to advance efficiently. The specific recommendation is that the utility is allowed to own and operate the substation storage as part of this RD&D pilot, proving the operational viability of this specific grid modernization technique.
    e. Monitoring, communications and control systems are necessary to operate the LICMP. Specific technologies will be evaluated to meet minimum islanding operational requirements while providing maximum overall cost effectiveness.
    f. Site control and permitting are typical challenges with deploying solar. However, in this case, there are a number of sites that have been identified previously as viable projects and are already in the existing PSEG LI FIT queue, surpassing the target amount of solar for this project.

2. What assets does the applicant and/or microgrid owner already own that can be leveraged to complete this project?
    a. The utility is an established entity providing full service to all customers in the region, including all necessary logistic and administrative resources. The utility owns and

operates the existing distribution system that will serve as the backbone of the LICMP integrating the distributed resources and loads.

b. The utility is currently contracting for 10 MW of PV resources within the LICMP area that will provide local generation and will constitute the bulk of generation capacity for operation of the Community Microgrid. The development of the LICMP with storage capacity will allow the utility to add 5 MW of additional PV, increasing local generating capacity by at least 50%.

3. How do the design, technology choice, and/or contracts ensure that the system balances generation and load?
   a. PV and storage were sized to provide reliable electric service to critical loads for an unlimited period in the event of either transmission or local distribution grid failure, and to do so without reliance on fuel delivery. When operating in islanded mode, the water pumping facilities will adjust their daily load profile to correspond with the solar profile. A portion of the total PV and energy storage will be located near ~~of~~ or adjacent to the critical loads with hardened service connections and in sufficient capacity to fully meet ongoing hourly and daily loads. Solar minimum generation and corresponding critical load profiles have been modeled for all hours throughout the year to establish combined minimum PV and storage capacity requirements.
   b. PV generation profile substantially corresponds with peak demand and transmission constraints, reducing or eliminating the use of local diesel generation, and providing reliable power independent of fuel supplies. The net qualifying capacity of PV has been established relative to peak transmission loading to determine the effective contribution of local PV as measured in MWh capacity.
   c. Storage is required to meet 24/7 critical loads during islanding events in combination with PV, while providing additional daily services in normal operation to realize maximum value, including addressing partial misalignment between PV generation profiles and peak transmission constraints. Storage capacity requirements have been established as peak (5 MW) and total (25 MWh) in conjunction with the installation of a total of 15 MW of PV at this substation to address projected peak transmission loading and to eliminate the historic use profile of local diesel generation. The planned PV capacity has been increased by 5 MW to take advantage of the ability of the storage facility to cost effectively integrate additional of PV while maintaining its primary functions.
   d. The utility will integrate planned LICMP PV and storage into existing load service under PPA operational terms. The storage facilities are integral to local balancing of high generation under both normal and islanded critical load service conditions, and the planned functions, operating characteristics, and flexibility to meet future needs will be incorporated into the contracture performance standards.
   e. Specific storage technologies will be evaluated in an RFP process to meet minimum islanding operational requirements while providing maximum overall cost effectiveness.
   f. Monitoring, communications and control systems are necessary to operate the LICMP. Specific technologies will be evaluated to meet minimum islanding operational requirements while providing maximum overall cost effectiveness.

4. What permits and/or special permissions will be required to construct this project? Are they unique or would they be required of any microgrid? Why?
    a. Permitting is required only for PV and storage siting and installation. No unusual or unique permissions are anticipated, although energy storage permits may be technology specific. Multiple comparable PV installations are in process in the same region of Suffolk County in response to local renewable energy goals and utility local generation capacity procurements.
    b. Interconnection permits are offered under the state approved procedures of the utility who is also the LICMP applicant and owner. Independent energy producers supplying PV generation to the utility LICMP are contractually responsible for obtaining all permits required for generation. The utility and energy producers will independently obtain building permits from the local jurisdiction for their respective facilities as required. All facilities are anticipated to be in the same jurisdiction.

5. What is the proposed approach for developing, constructing and operating the project?
    a. This is a utility owned and operated Community Microgrid project interconnecting its existing grid and planned storage facilities with contracted generation from independent producers.
    b. Interconnection and other grid facilities will be constructed by utility personnel. Generating facilities will be developed and operated independently under terms of the power purchase agreements with the utility. Energy storage and communications facilities will be installed by suppliers under procurement contract to the utility for ownership and operational support.
    c. The local generation and storage facilities will be integrated into regular grid operations to serve utility customers while eliminating the use of local diesel generation, contributing to avoiding transmission upgrades that would otherwise be required, and managing wholesale power purchases to reduce costs.
    d. During emergency islanded operation the utility will operate LICMP resources to maintain continuous power to critical loads and supply additional available power to priority loads.

6. How are benefits of the microgrid passed to the community? Will the community incur any costs? If so, list the additional costs.
    a. The community will benefit from reliable operation of critical and priority loads during system outages——this is very important when needed, and results in $334,000 per day of avoided local outage value for the community served by the LICMP circuits during regional outage events, however the likelihood of such events is difficult to predict.
    b. The community will also benefit from additional economic activity, including hundreds of job years, resulting from local investment in project facilities, as well as net ratepayer savings.
    c. PV Site leasing adds additional annual income value to properties owners in the LICMP service area.
    d. No additional costs are anticipated to the community, or net costs to ratepayers in general.
7. What will be required of the utility to ensure this project creates value for the purchaser of the electricity and the community?

a. The utility will be the primary purchaser of the electricity on behalf of its customers.
b. To ensure value, the utility must evaluate the infrastructure and contractual costs against alternatives, including the development of new transmission resources to supply reliable power to critical loads and the capacity to meet peak loads. The following studies and analyses have been performed by the utility and the Clean Coalition to identify needs, costs, and net savings:
    i. Load Growth Forecast
    ii. Transmission Deficiency Forecast
    iii. Transmission Deficiency Mitigation - Upgrade Cost Analysis
    iv. Local Generating Siting Capacity Analysis
    v. Local Solar Resource – Generating Capacity Output Analysis
    vi. Peak Load Solar Mitigation – Generation/Load Profile
    vii. Circuit PV Hosting Capacity Analysis - Generation/Load Profile
    viii. Energy Storage Sizing Analysis – Peak Load Mitigation, Peak Local Generation Mitigation, Critical Load Service
    ix. Solar + Energy Storage Avoided Cost Analysis – Capacity Value, Energy Arbitrage Charge/Discharge Modeling
    x. Employment and Economic Impact Analysis
    xi. Critical Load Service – Population Impact Analysis
c. Final procurement requires review of responses to utility initiated Request for Offers and vetting of contractual terms to ensure performance within planned cost and operational parameters.
d. Power purchase and capital expenditures are subject to regulatory oversight to ensure ratepayer value.

8. Have the microgrid technologies (including but limited to: generation, storage, controls) been used or demonstrated before? If yes, describe the circumstances and lessons learned.
    a. Yes. PV is a well-established generation source.
    b. Utility scale storage has been employed in a limited number of installations and represents both established and rapidly developing technologies resulting in a range of cost effective capabilities. California investor owned utilities are in the process of procuring 1,325 MW of energy storage under the direction of California’s Public Utilities Commission, and have already contracted over 200 MW earlier than planned due to its cost effectiveness relative to alternative peak generation and grid investments. Specific selection will be determined through evaluation of RFO responses and performance assurance.
    c. The proposed Monitoring, Communications & Control systems have been implemented in multiple locations, including Department of Defense microgrids, as validated in their RFI responses to this project.
        i. Communication and control technologies are both long established and rapidly developing, as are the industry standards governing their functionality and compatibility. Established standards and equipment are adequate for the limited requirements of this project as planned, however investment should consider and accommodate anticipated additional functionality to extend optimization of distributed resources to include utility customers, and to ensure cost effective implementation.

ii. The applicant is in consultation with providers to evaluate currently available alternatives in relation to IEEE 1547 standards revisions and the Rule 21 Smart Inverter Working Group communication recommendations. Specific selection will be determined through evaluation of RFO responses and performance assurance.

9. Describe the operational scheme, including, but not limited to, technical, financial, transactional and decision-making responsibilities that will be used to ensure this project operates as expected.
    a. PSEG LI will operate the LICMP as part of its existing distribution operations. As such, the utility purchases energy directly from the wholesale market and from suppliers under negotiated contract, and sells the power to all customers under the applicable tariff. No change in existing financial or transactional practices is required or anticipated. PPA contracts normally cover the areas of operational standards, responsibilities, compensation, and remedies for non-performance of suppliers.
    b. Capital investment in utility owned grid assets, including energy storage and system controls, are subject to existing standards and oversight. The utility plans to maximize the value of the assets by operating them to minimize peak power market purchases and substitute the least marginal cost purchases available throughout the day. Initial energy storage arbitrage value analysis has determined this to be viable and valuable, and the utility seeks to gain operational experience to optimize this potential.
    c. Emergency islanding operation in service of critical loads is designed to occur autonomously in response to grid outage conditions, utilizing standard switching and signaling equipment employed throughout the distribution system.

10. How does the project owner plan to charge the purchasers of electricity services? How will the purchasers' use be metered?
    a. LICMP project owner is the utility. Electricity services purchased by the utility will be provided and metered under PPA contract with individual facilities. The provision of electrical service and sale of electricity by the utility for purchase by its customers is regulated by tariff and will not change from existing practices.
    b. The utility may explore the opportunity to offer new tariffs to customers for the provision of critical or prioritized load service during emergency operation, or for load management or the integration of customer sited distributed energy resources, or the application of advanced metering devices. However this is beyond the scope of the initial implementation and operation of the project.

11. Are there business/commercialization and replication plans appropriate for the type of project?
    a. This project will demonstrate a LICMP model replicable throughout this transmission constrained region and replicable by other utilities. The analytical approach and valuation methods are applicable to the appropriate design of Community Microgrid Projects for any distribution system in which DER are offering services, and the valuation of those services.

12. How significant are the barriers to market entry for microgrid participants?
    a. Suppliers offering to provide electric services to the utility will be required to participate in utility procurement processes. Utility customers will maintain their existing

relationship with the utility. The Monitoring, Communications & Control systems will need to rely on the utility's existing (or new) communications infrastructure.
   b. There exists a financial disincentive for investor owned utilities to seek solutions where these utilities will forgo or reduce capital investment opportunities through the use of DER capacity or services owned by third parties.

13. Does the proposer demonstrate a clear understanding of the steps required to overcome these barriers?
    a. Yes, the utility is familiar with the requirements of its procurement processes and it adjusts these as necessary to achieve effective participation.

3.5 Financial Viability

1. What are the categories and relative magnitudes of the revenue streams and/or savings that will flow to the microgrid owner? Will they be fixed or variable?
   a. The local generation capacity, energy and services produced by the LICMP will contribute to the utility's resource supply and avoid alternate costs.
   b. The region is projected to have increasing load resulting in a load service capacity deficiency of 63 MW by 2022 that would require $300 in transmission investment based on transmission planning studies performed by the Long Island Power Authority. This new transmission may be avoided through the development of local resources at lower cost. The LICMP resources will contribute to the total local capacity required to avoid the new transmission investment while also supplying local power in the event of a transmission interruption.
   c. As designed, the LICMP will incorporates 10 MW of PV, which will offer a 20% net qualifying capacity value against peak transmission load service, contributing 2MW to the total required peak transmission load reduction. This is valued at $9.5 million as a portion of the total avoided transmission fixed cost value.
   d. As designed, the 5MW/25MWh storage facilities will directly contribute 5MW to peak transmission load reduction, valued at $23.8 million as a portion of the total avoided transmission fixed cost value.
   e. The storage facilities will support higher penetration of PV on the utility circuits, allowing a planned additional 5MW of PV, providing 1MW of transmission capacity offset, valued at $4.8 million as a portion of the total avoided fixed cost transmission value.
   f. The storage facilities will also reduce NYISO capacity charges by $6 million through 2022, and by more than $1 million annually thereafter. Capacity charges are variable and escalate over time.
   g. The energy storage facilities will allow the utility to shift wholesale power purchases from daily peak pricing periods to off peak periods, realizing net savings in energy purchases of $2.5 million by 2022 and more than $500,000 annually thereafter. Energy peak pricing differentials are variable and have historically escalated over time.
   h. Together, the development of new local resources operating within the LICMP will contribute $46.6 million in avoided costs by 2022, and at least $1.5 million escalating annually thereafter. Of this total, $9.5 million would occur through the development of PV resources alone without the storage and control systems.

2. What other incentives will be required or preferred for this project to proceed? How does the timing of those incentives affect the development and deployment of this project?
    a. Added locational value was reflected in PV procurement offers and selection.
    b. No new or additional incentives are required or requested.

3. What are the categories and relative magnitudes of the capital and operating costs that will be incurred by the microgrid owner? Will they be fixed or variable?
    a. The total installed capital costs for 5MW/25MWh of storage capacity for energy services over a 20-year period is on the order of $20 million. The RFP will evaluate the initial capital costs relative to the lifecycle costs and efficiency over the planned operation.
    b. Capital costs associated with local distribution system communications modernization to accommodate planned PV, storage, and islanding for critical load service will be determined based upon final siting plans and operational requirements but are not anticipated to exceed $2 million for the scope of the planned installations.
    c. The operating costs for energy storage are included in the 30% round trip cost of use, including losses and facility operation. These costs are reflected in the modeled value of daily energy arbitrage utilizing the available storage capacity for off peak power purchases to replace peak power purchases for a net savings on energy purchases.
    d. PPA contracts associated with the independent energy suppliers will provide long term fixed rate energy supplies and services related to variable but predicable output associated with planned 15MW of PV capacity for sale to customers.

4. How does the business model for this project ensure that it will be profitable?
    a. The proposed LICMP realizes the operational potential of integrated high capacity distributed energy resources with visibility and control on the distribution system and is not dependent upon direct profitability. However, the LICMP design is optimized to maximize value and as described above is anticipated to result in total avoided costs in excess of $46 million through 2022, yielding net cost savings on the order of $20 million. Additional savings will accrue throughout the life of the equipment and contracts. The Location specific incentives are dependent upon actual avoided cost assurance criteria (sufficient procurement/deployment to defer additional transmission investment)
    b. Suppliers will be subject to independent investment performance and risk reflected in their offers, however neither supplier risk nor profit accrue through the contracts to the utility as the LICMP owner.

5. Describe the financing structure for this project during development, construction and operation.
    a. The LICMP procurement and financing structures are still being evaluated. It is anticipated that many solution providers will offer financing opportunities.

3.6 Legal Viability

The Contractor shall describe the legal terms and conditions and other requirements necessary to develop and operate the microgrid by addressing no less than the items below:

1. Describe the proposed project ownership structure and project team members that will have a stake in the ownership.
    a. Solar facilities will be owned by private entities that will sell all of the generated solar power to the utilities via the LIPA FIT.
    b. Beyond the solar facilities, LICMP assets and solutions, including grid upgrades, energy storage facilities, monitoring, communications, and control systems, and other DER solutions, will be owned by the utilities or private entities that the utilities might select.

2. Has the project owner been identified? If yes, who is it and what is the relationship to the applicant? If no, what is the proposed approach to securing the project owner?
    a. Aside from the PV facilities, LICMP ownership structures are still being evaluated.
    b. With respect to PV, independent PV facility owners are anticipated to provide solar energy to the LICMP under contract with the utility.

3. Does the project owner (or owners) own the site(s) where microgrid equipment/systems are to be installed? If not, what is the plan to secure access to that/those site(s)?
    a. LICMP ownership structures are still being evaluated, but it is anticipated that some LICMP elements will be located on utility property. It is also anticipated that at least in some cases energy storage and PV facilities associated specifically with service to critical loads will be located on the property of those critical facilities.
    b. Independent PV facility owners will secure siting for their facilities.

4. What is the approach to protecting the privacy rights of the microgrid's customers?
    a. The utility is the purchaser of power and services on behalf of its customers. Established privacy rules will not be changed as the utility purchases, manages, or sells electricity and related services.

5. Describe any known, anticipated, or potential regulatory hurdles, as well as their implications that will need to be evaluated and resolved for this project to proceed. What is the plan to address them?
    a. Since the LICMP is designed to rely upon existing contractual and customer standards, no regulatory changes are anticipated in order to deploy and operate the LICMP as planned.

Solution Profile

This section describes all the assets and characteristics of the LICMP, including the specific configuration and how the assets, including loads, will be managed and optimized. The configuration diagrams in the monitoring, communications, and control section illustrate how the LICMP will perform the specific functions required to satisfy the project goals. All assets are controlled by the utility and feature the following:

- Energy Storage: Central energy storage facility of 5 MW/25 MWh connected to the substation via a dedicated feeder, plus smaller distributed energy storage facilities located at the critical load sites, connected directly to existing feeders and controlled by the utility.
- Solar PV: 15 MW of PV located at optimal sites across the target grid area, including at critical load sites and nearby sites, all connected directly to existing feeders.
- Critical & Priority Loads: In backup mode, during a feeder outage the critical loads are served locally by onsite, or nearby, combinations of distributed solar and storage. The relevant solar and energy storage will be shunted to power critical loads directly. Due to the community scale of this solution, other priority loads can also be served during a feeder and/or transmission outage.
- Monitoring, Communications & Control: As described in more detail below, a sophisticated monitoring, communications, and control solution will orchestrate and optimize all assets and provide advanced load management. Monitoring and control points are strategically located along the configuration to establish an appropriately hierarchical decision system. For example, the onsite assets will perform autonomous controls as determined by the central system then feed into the next tier of control aggregation at the substation.

The following sections describe this system in more detail.

Monitoring, Communications & Control (MC^2)

Based on the project configuration diagram and descriptions below, the MC^2 solution manages the Community Microgrid assets—keeping power, voltage, and frequency in balance and optimized while interfacing with PSEG LI's existing smart grid infrastructure. Optimization will be achieved consistently across power, energy, and costs.

An LICMP Request for Information (RFI), detailing the requirements for the LICMP MC^2 solution, were distributed to leading vendors in late June 2015. Responses were received in July 2015, with follow up discussions occurring in July and August 2015. These responses, submitted by vendors with existing solutions already deployed at multiple microgrid sites including those at Department of Defense locations, provided details that both contributed to and satisfy the LICMP design as outlined in this document.

To help describe the MC^2 operating modes, the loads have been divided into three tiers, as follows:

Tier 1: The identified critical facilities that will operate continuously during outages by utilizing the solar and energy storage located onsite, plus solar located nearby in certain cases. This mode enables the critical facilities to be supported during either a distribution grid or transmission grid outage.

Tier 2: With the DER assets in place across the LICMP area, there will be excess capacity to supply loads beyond the critical facilities during an extended outage. As such, PSEG LI Operations can supply power to prioritized loads during outages, separate from the critical, Tier I facilities. This mode enables

Tier 2 loads to be supported during a transmission grid outage, as well as for certain distribution grid outages.

Tier 3: These are the remaining loads that would be shed during an outage.

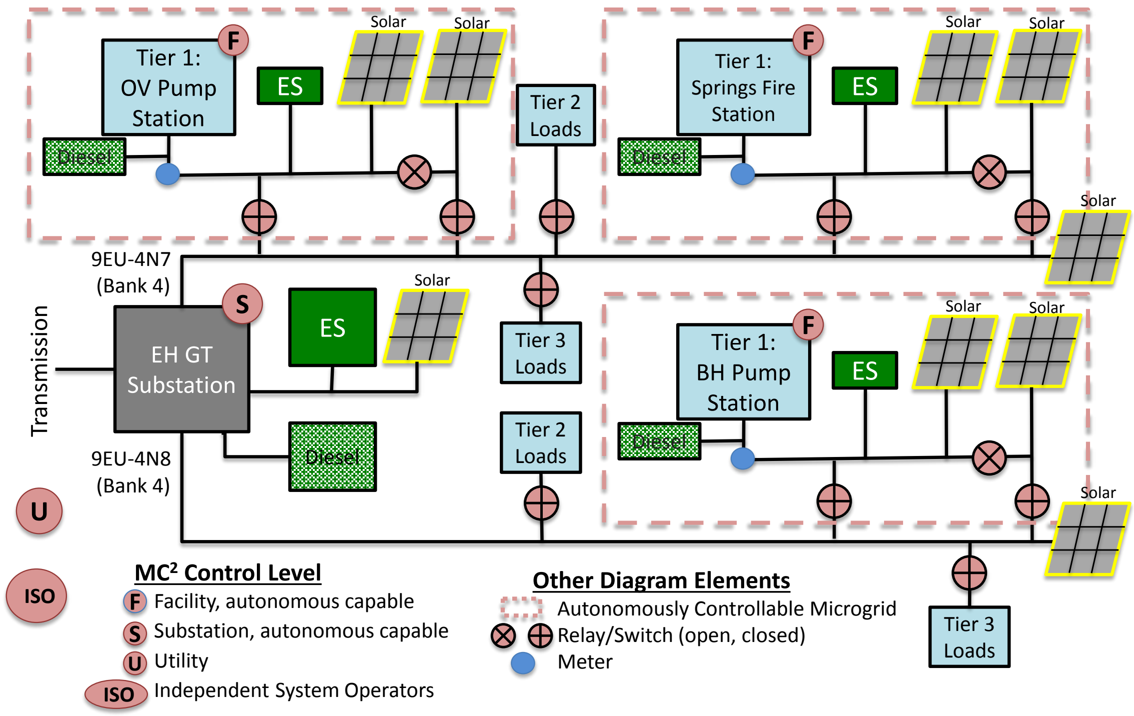
Operational States

All DER installed by the project will be in front of the meter and thus available to the utility for control and dispatch.

Normal Operations

During normal operations, the planned 5 MW battery will be used as a low-carbon energy source for peak load management during the heavy afternoon and evening demands of the summer season. The battery will minimize use of the existing 6 MW (3 x 2 MW) diesel generator capacity currently located at the East Hampton GT substation. In addition, other grid services will be available from the battery during off-peak times. Figure 1 below illustrates the configuration during normal operations, showing all assets and switch modes. Note that the diesel generators located at the critical facility sites exist already and are used solely in cases of outages. Unlike the LICMP DER assets, diesel generators cannot be used to offset system load, nor can they backfeed energy beyond the customer meter.

Figure 1: Operation of Microgrid Assets in Normal Operating Mode



Feeder Outage

During backup operations caused by feeder issues the following occurs (see Figure 3 for switch settings):

- **Tier 1 loads**: Relays switch the Tier 1 sites into islanded operation. After isolation from the PSEG LI system, the reserve power in the energy storage serves the critical loads. With the Tier 1 sites isolated and energized behind the meter, the onsite assets continue to power their loads under local control. In some cases, nearby energy storage and PV is isolated from the PSEG LI system and transferred to supplement the emergency diesel site resources.
- **Tier 2 & 3 loads**: Upon loss of feeder, the remaining loads are not served until the feeder is restored. At the utility's discretion and determination that a portion of the feeder is intact and safe to energize, Tier 2 and 3 loads are disconnected to allow other DER assets to power Tier 2 loads that are reconnected.
- The energy storage reserve SoC and the PV will serve loads with excess PV used to recharge the battery during daylight hours. Diesel is engaged if there is insufficient energy storage capacity to continue operations to the next day of solar recharge.
- Load management commands are sent out to the connected loads for load reduction and/or for load shifting to match the PV generation and energy storage recharge cycle (see Figure 2). Tier 2 loads that cannot comply can be shed.
- After the feeder outage is corrected, the aggregate controller assists the operations center in sequencing the reconnection of Tier 1 loads and Tier 2 loads that were shed.

Figure 2: Example of Shifting Load Profile for Solar Generation Alignment and Reducing Magnitude

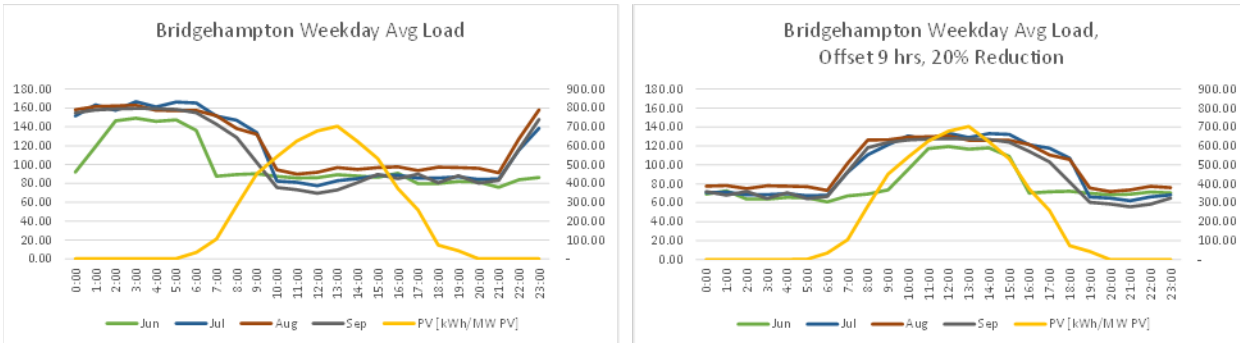
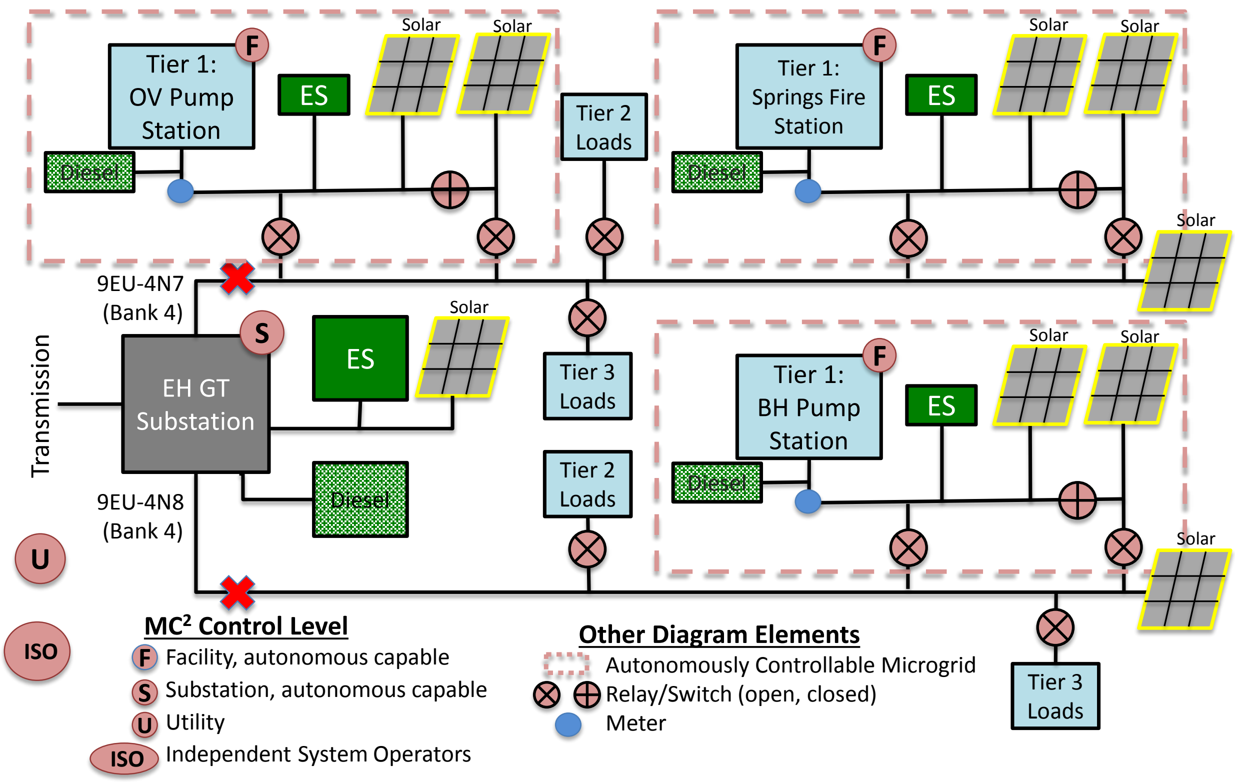


Figure 3: Operation of Microgrid Assets in Backup Mode, Tier 1 Loads Only



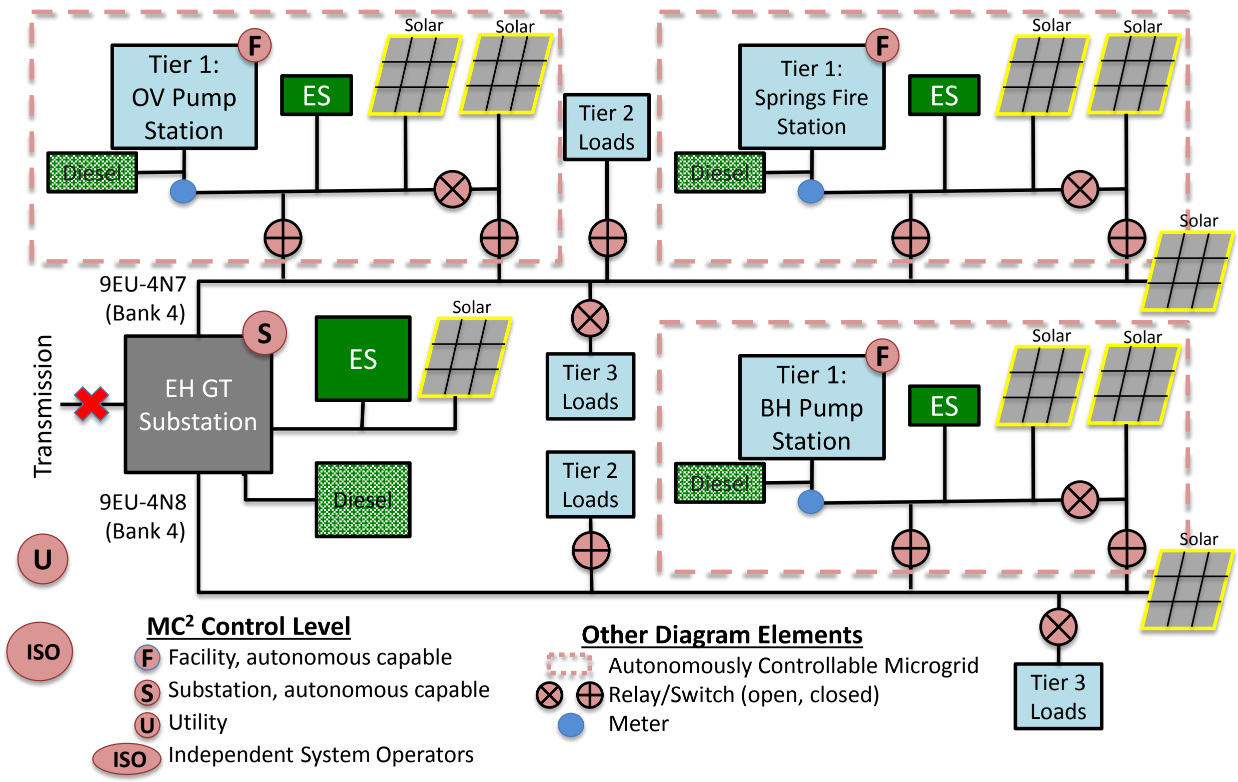
Transmission Outage

During backup operations caused by transmission outage (see Figure 4) the following occurs. Essentially, this is the same as the feeder outage, but the feeders are intact and can use power to supply both feeders.

- Initially, Tier 1 loads are islanded as in the feeder outage scenario and Tier 2 and 3 loads are shed.

- The substation is islanded from the transmission grid.
- If the power and energy source inventory available to the substation controller at that time shows sufficient capacity, the energy storage & large PV assets are reconnected to the feeders. Tier 2 loads are reconnected as the power and energy inventory allows.
- Load management commands are sent out to the connected loads for load reduction and/or load shifting to match the PV-energy storage recharge cycle. Tier 2 loads that cannot comply may be shed.
- PV recharges the energy storage during daylight hours. Diesel is only engaged if there is insufficient energy storage capacity to continue operations to the next day of PV recharge.
- After transmission power is restored, the aggregate controller assists grid operations in reconnecting loads or black start if needed.

Figure 4: Operation of Microgrid Assets in Backup Mode, Tier 1 & 2 Loads Only



Advanced load management will also be utilized to lower peaks, “follow” the solar generation and energy storage SoC, and shed non-priority and non-critical loads during outages, as described above. This further optimizes the LICMP outcomes. Home and Building Energy Management Systems will be integrated with and controlled by the MC^2 solution to achieve load reductions during evening peaks and/or outages and increase loads during excess solar output. For example, implementing air conditioner pre-cooling in the afternoons during periods of high solar output will simultaneously reduce loads during a summer evening peak while addressing solar over-generation that may occur during the day.

As demonstrated by the above diagrams and MC^2 operational modes, the LICMP will satisfy multiple NY Prize goals during both normal and emergency operations, serving thousands of customers rather than just a single site.

Note that the MC^2 solution will interoperate with the PSEG LI distribution grid as required in the document PSEG Long Island Smart Grid Small Generator Interconnection Screening Criteria for Operating in Parallel with LIPA's Distribution, which is available at https://www.psegliny.com/files.cfm/SGIP-criteria.pdf.

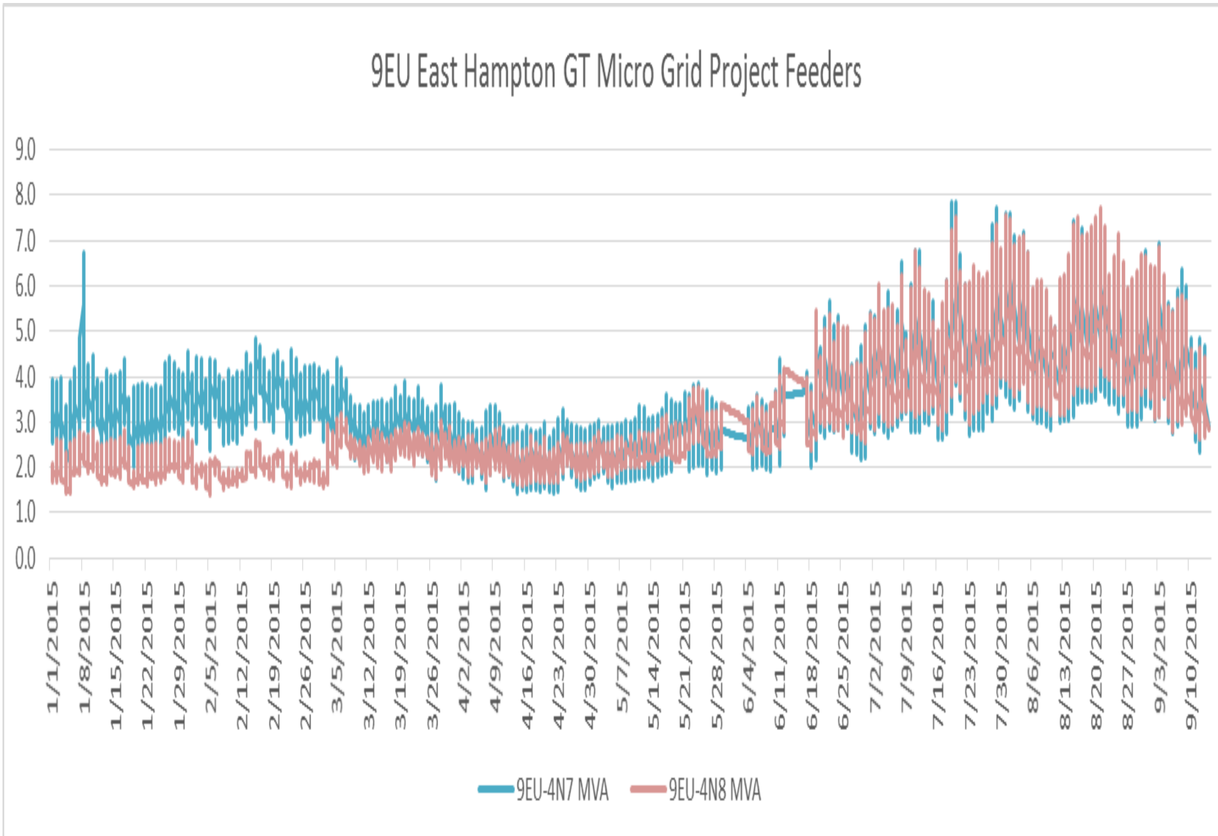
In terms of additional MC^2 requirements, a recommended approach is being proposed by the SIWG—see the Appendix for more details. In addition, specific standards for communication and interoperability are being developed by the SunSpec Alliance. The LICMP MC^2 solution will incorporate and support industry-wide and standardized approaches wherever possible and practical.

The additional Solution Profile details that support the above MC^2 operations and project configuration are provided below, organized by the primary variables comprising the LICMP such as Feeder Loads, Critical Facility Loads, and DER Assets.

Feeder Loads

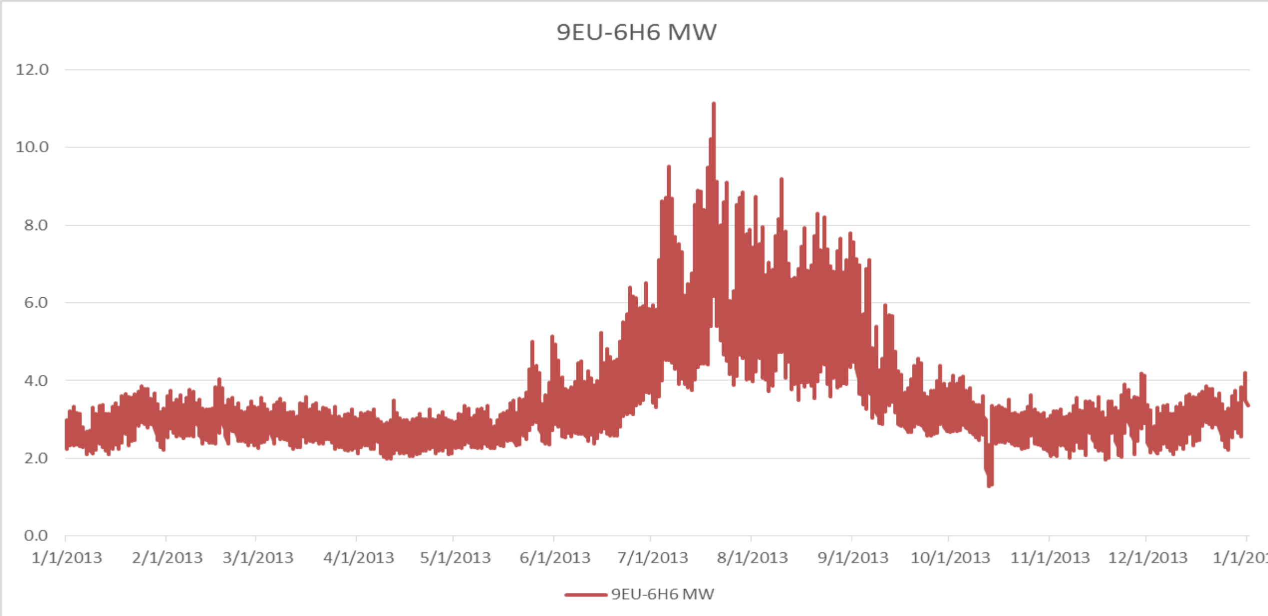
Figure 5 below shows the existing loads (SCADA data) from the target grid area—the two feeders comprising Bank 4 of the East Hampton GT substation. This represents the "System Load" for the LICMP. These feeders are relatively new, so a complete year's data is not yet available. A reference feeder from the same substation with the profile from the 2013, which had a very hot summer, is shown in Figure 6. The large summertime increase in load is evident in all of the data.

Figure 5: SCADA Load Data for the Two Bank 4 Feeders, January – September 2015[a]



a: Load data provided by PSEG-LI for 2015

Figure 6: Reference Feeder in Same Substation from "Hot" 2013[b]



b: Load data provided by PSEG-LI for 2013

Below (Figure 7 and Figure 8) are the daily load profiles for each of the reference feeders broken into both weekday and weekend hourly averages per month. The plots are of the average hourly values for weekdays and weekends.

Figure 7: 9EU6-6H6 Weekday Hour Average Load

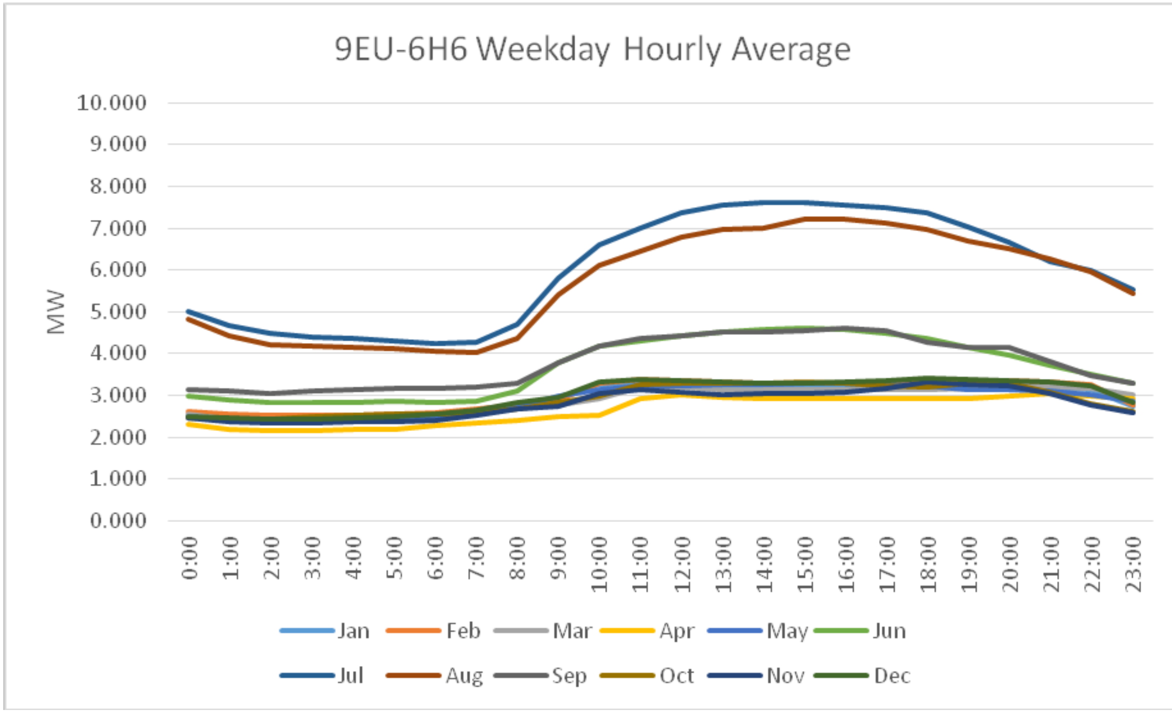
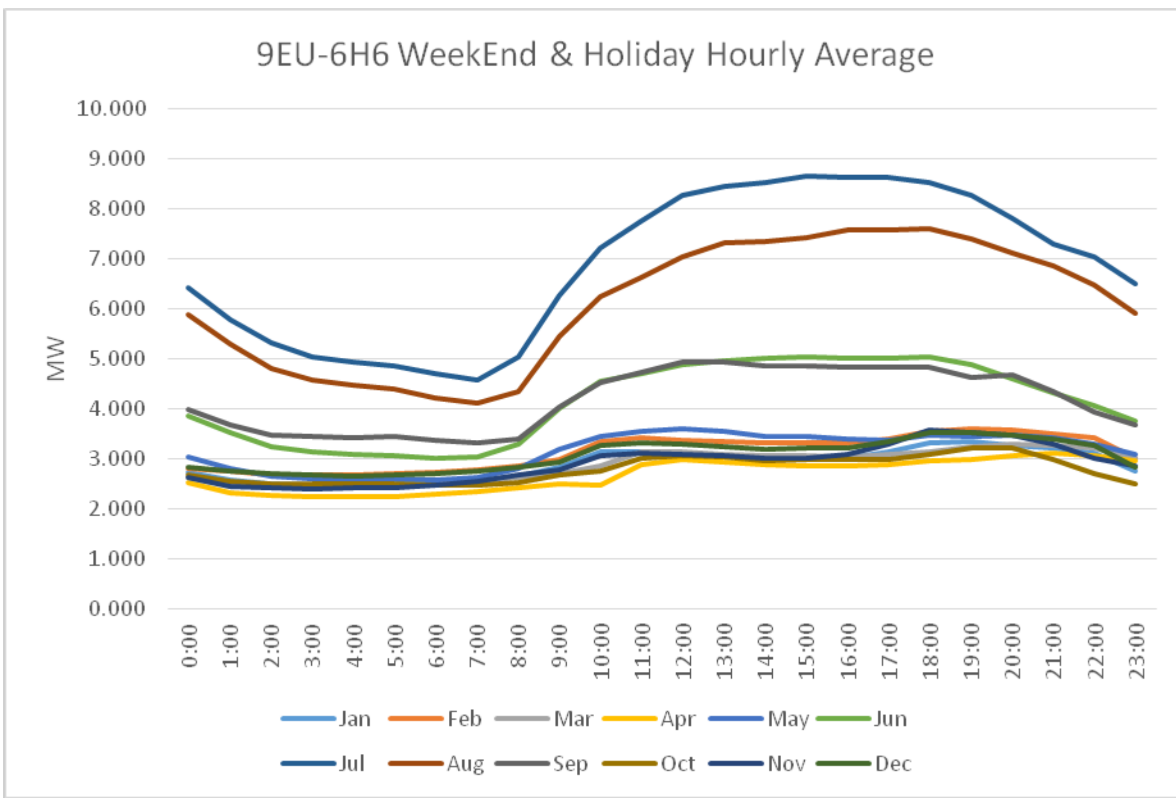


Figure 8: 9EU-6H6 Weekend and Holiday Hourly Average Load



Critical Facility Loads (Tier 1 Loads)

The project features three critical facilities—Tier 1 load sites, with onsite DER. The onsite DER will perform two functions: 1) support the local grid during normal operations, such as reducing local peaks; and 2) support the onsite critical loads during emergency backup operation.

The Tier 1 critical facilities are:

- Bridgehampton Road Well Field, Pump Station and Operations Center; 42 Montauk Highway, East Hampton, NY 11937
- Oak View Highway Well Field and Pump Station; 127 Oak View Highway, East Hampton, NY 11937
- Springs Fire District facility; 179 Fort Pond Boulevard, East Hampton, NY

All facilities have existing onsite diesel generators that will remain in place. The DER sizing will enable each facility to maintain ongoing operations with renewable energy in the event of an extended outage.

In terms of load management during an outage the critical facilities will match their load profiles to the solar power availability, to the extent possible, in order to minimize the use of energy storage.

Figure 9 and Figure 10 show are the load profiles for the Bridgehampton Pumping facility for the available metering data. Figure 11 and Figure 12 show the comparable data for the Oak View station.

Figure 9: Bridgehampton Pumping Station Loads, Weekday

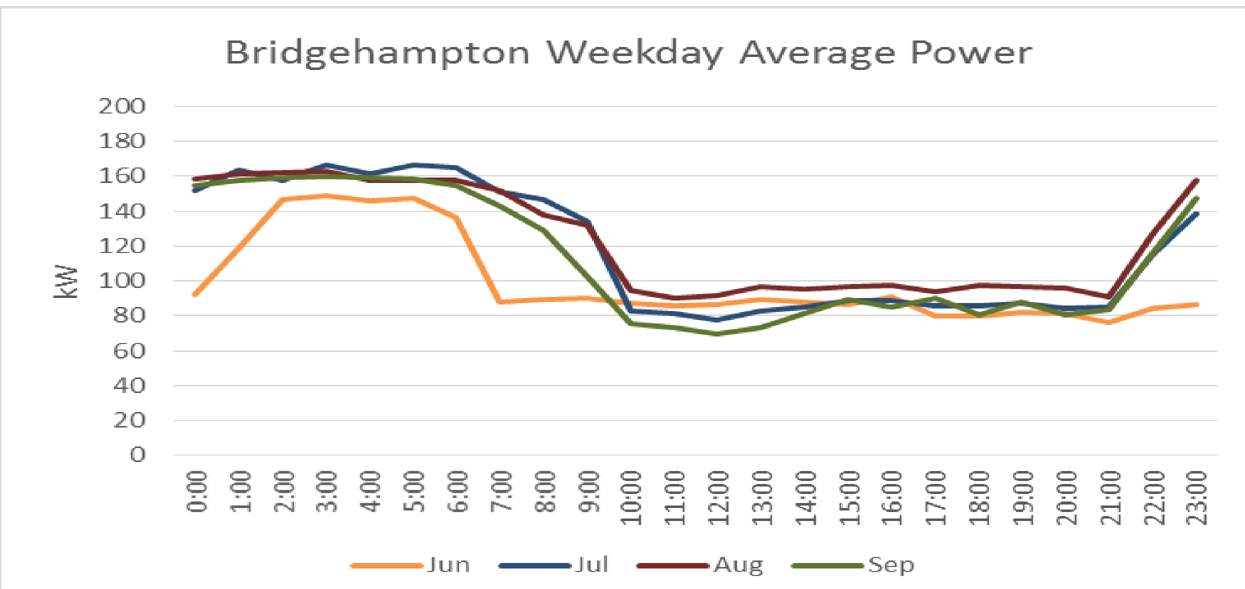


Figure 10: Bridgehampton Pumping Station Loads, Weekend & Holiday

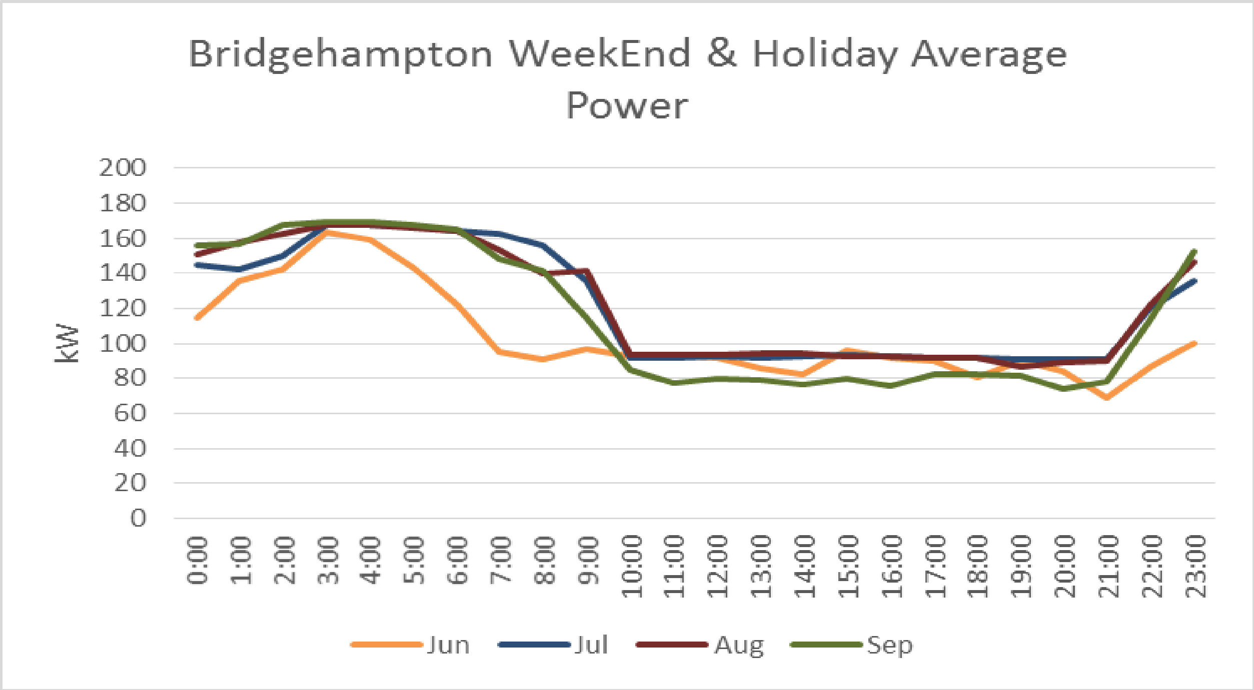


Figure 11: Oak View Pumping Station Loads, Weekday

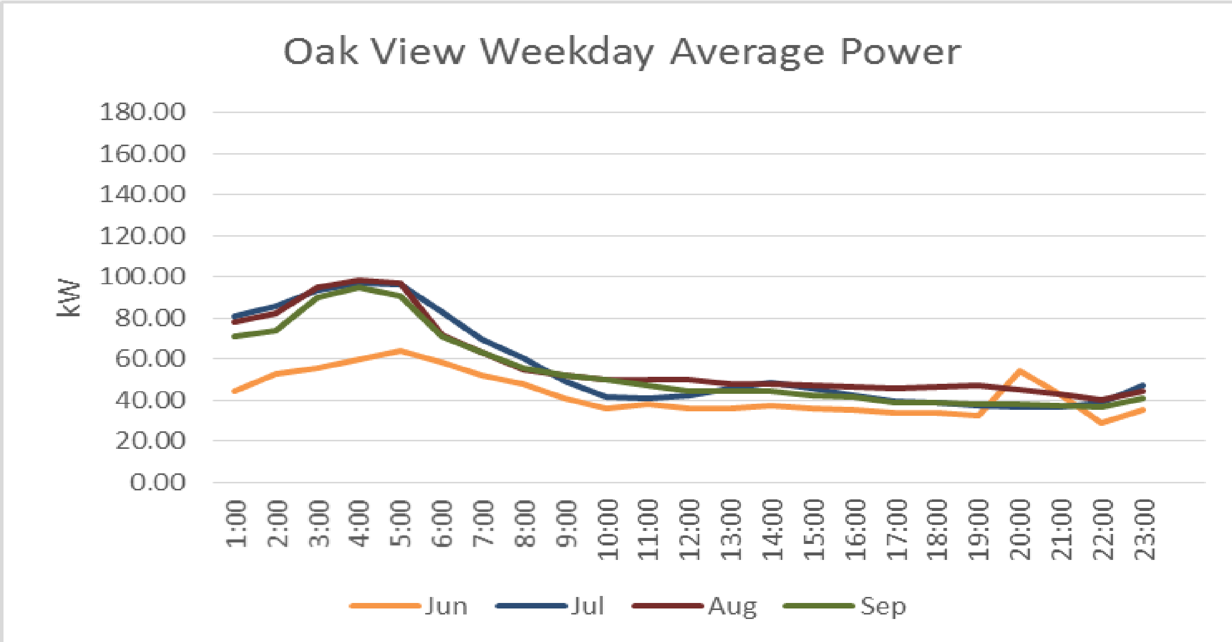
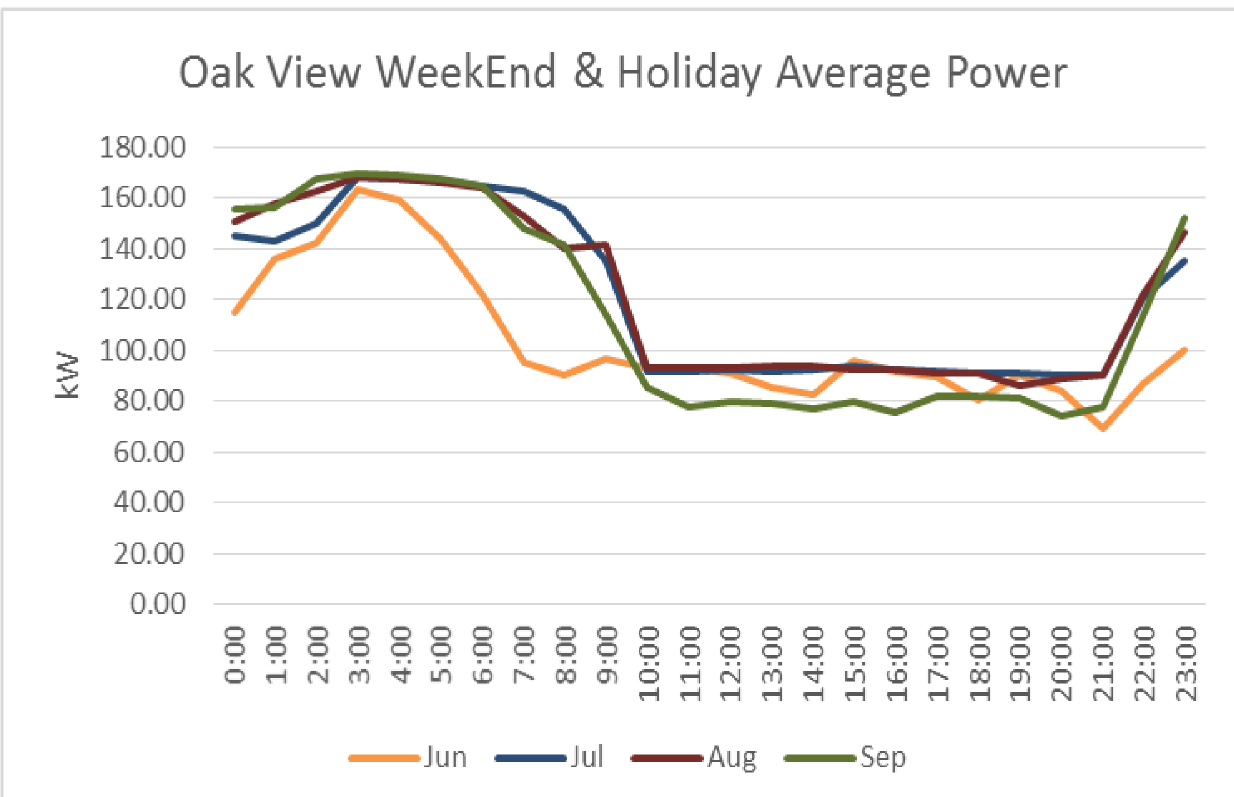


Figure 12: Oak View Pumping Station Loads, Weekend & Holiday



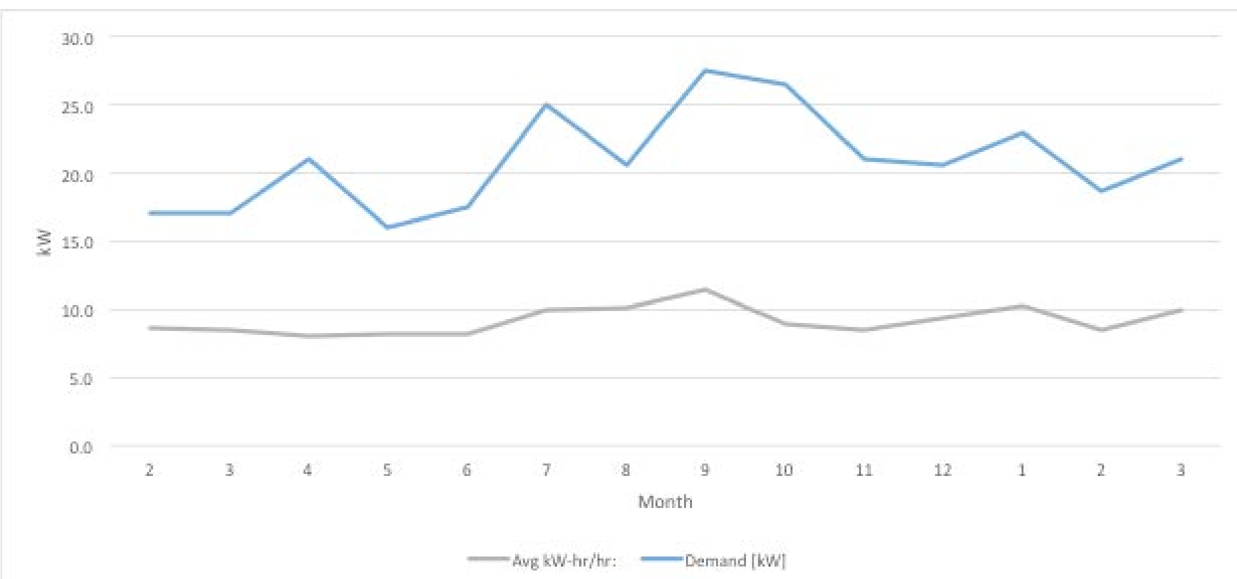
Notes for pumping stations:

- Both pumping stations run more often at night to avoid peak rate charges. This would not be a necessity during emergency operations.
- Automated Metering Infrastructure (AMI) was only recently installed, so only 4 months of data have been acquired and analyzed. Fortunately, the range includes the heavy summer months, and the data show power consumption increasing in July and August.
- The peak power is 178 kW for Bridgehampton and 103 kW for Oak View.
- Onsite diesel generation: 250 kW for Bridgehampton and 125 KW for Oak View

Table 2: Springs Fire Station Loads

kWh	5,960	5,920	5,360	6,440	5,280	8,320	7,320	7,920	6,640	5,920	7,000	9,120	4,720	8,080
Days	29	29	28	33	27	35	30	29	31	29	31	37	23	34
Demand [kW]	17.0	17.0	21.0	16.0	17.5	25.0	20.5	27.5	26.5	21.0	20.5	23.0	0.0	21.0
Month:	2	3	4	5	6	7	8	9	10	11	12	1	2	3
Avg kWh/Day:	205.5	204.1	191.4	195.2	195.6	237.7	244.0	273.1	214.2	204.1	225.8	246.5	205.2	237.6
Avg kW/hr:	8.6	8.5	8.0	8.1	8.1	9.9	10.2	11.4	8.9	8.5	9.4	10.3	8.6	9.9

Figure 13: Springs Fire Station Power Demand Estimates



Notes for Fire Station:

- Table 2and Figure 13 are based on normal kWh billing data for the fire station. There is no AMI data available.

- Average power in each hour was estimated by dividing the average daily kWh by 24.
- There is a small amount of late summer and mid-winter peaking.
- The kW demand charges from each bill are also shown.

Distributed Energy Resource (DER) Portfolio

Following is the planned DER portfolio spanning the entire LICMP target grid area comprising the two feeders. This includes the DER located at the three critical facilities.

Solar PV

The LICMP will feature up to 15 MW of solar across the two feeders. The 15 MW of PV will be distributed among a specific number of sites that include the three critical load facilities. Other PV sites may include the airport, a recycling center, and large municipal and commercial locations. The following table lists the sites with the largest solar potential in the LICMP grid area. These sites comprise both existing FIT-2 proposals submitted to PSEG-LI and a separate solar siting survey conducted by the Clean Coalition.

With the planned 15 MW (DC) of PV generation, the LICMP would provide about 45% (20k MWh) of the annual energy (44k MWh) consumed on the two feeders in Bank 4 at the East Hampton GT substation.

Table 3: Solar Siting Survey Projects

Site name, identifier, occupant or description of structure if known	Street address	Latitude of structure	Longitude of structure	Surface area in sqft	Structure type	PV power density assesment	Estimated PV Power [W_DC]	Total PV potential at this address [W, DC]	Comments re area or assessment
EH Airport	Town Line Road and Me	40.961569	-72.256545		Brown_Fld		7,500,000	7,500,000	4 Projects
EH Airport Plane Pkg 1	194 Daniels Hole Rd	40.960419	-72.246686	60,000	Pkg_Lot	Medium	300,000	300,000	Excluded helo area
EH Airport Plane Pkg 2	208 Daniels Hole Rd	40.961182	-72.249327	73,000	Pkg_Lot	Medium	365,000	365,000	Excluded helo area
EH Airport Rental Car Pkg	192 Daniels Hole Rd	40.961406	-72.246908	8,400	Pkg_Lot	Medium	42,000	42,000	
EH Airport Hangars	200 Daniels Hole Rd	40.961739	-72.247887	38,000	Roof_Flat	High	266,000	266,000	2 buildings
EH Recycling Ctr	260 Springs Fireplace R	40.987350	-72.168783		Brown_Fld		6,324,000	6,324,000	4 Projects
Accabonac Project	Accabonac Rd and Harri	40.998569	-72.158014		Brown_Fld		3,000,000	3,000,000	2 Projects
Old NW 2.0	18 Old Northwest Rd	40.981619	-72.218760		Brown_Fld		2,000,000	2,000,000	
SCWA Bridgehampton	42 Montauk Highway	40.955114	-72.207627		Brown_Fld		5,000,000	5,000,000	
SCWA Oak View	127 Oak View Highway	40.976790	-72.193194		Brown_Fld		5,000,000	5,000,000	
Springs Fire Dist	179 Fort Pond Blvd	41.026012	-72.157856		Brown_Fld		TBD	-	
EH High School	2 Long Ln	40.969513	-72.200466		Edu		-	808,000	
EH HS Pkg Lot	2 Long Ln	40.969135	-72.200732	86,000	Pkg_Lot	Medium	430,000	-	
EH HS BLdg	2 Long Ln	40.970038	-72.199798	54,000	Roof_Flat	High	378,000	-	
John Marshall Elementary	3 Gingerbread Ln	40.961315	-72.194983		Edu		-	309,000	
John Marshall Bldgs	3 Gingerbread Ln	40.960714	-72.195623	37,000	Roof_Flat	High	259,000	-	
John Marshall Pkg Lot	3 Gingerbread Ln	40.961992	-72.194924	10,000	Pkg_Lot	Medium	50,000	-	
YMCA EH Pkg Lots	2 Gingerbread Ln	40.962796	-72.192343	60,000	Pkg_Lot	Medium	300,000	300,000	2 Lots next door
EH Middle School Bldgs	76 Newtown Ln	40.965197	-72.188936	10,100	Roof_Flat	High	70,700	70,700	
Town of EH City Offices	159 Pantigo Road	40.968770	-72.172252	10,700	Pkg_Lot	Medium	53,500	53,500	
Commercial Parking Lot 1	84 Park Pl	40.963043	-72.187417	40,500	Pkg_Lot	Medium	202,500	202,500	
EH Golf Club	Abrahams Path?	40.990781	-72.161105	18,000	Pkg_Lot	Medium	90,000	110,000	
Maidstone Club Pkg1	Old Beach Ln?	40.952134	-72.173422	17,000	Pkg_Lot	Medium	85,000	133,500	
Maidstone Club Pkg2	Old Beach Ln?	40.950634	-72.175059	4,000	Pkg_Lot	Medium	20,000	-	
Maidstone Club Pkg3	Old Beach Ln?	40.951284	-72.173182	5,700	Pkg_Lot	Medium	28,500	-	
beach parking	Ocean Ave	40.944956	-72.194505	37,000	Pkg_Lot	Medium	185,000	200,000	
beach parking	Ocean Ave	40.943259	-72.195042	3,000	Pkg_Lot	Medium	15,000	-	
swimming pool pkg	Abrahams Path?	40.978548	-72.157221	4,000	Pkg_Lot	Medium	20,000	110,000	
EH Indoor Tennis Pkg	by EH airport	40.961749	-72.240941	12,000	Pkg_Lot	Medium	60,000	60,000	
beach parking	Two Mile Hollow Ln	40.956567	-72.159817	28,000	Pkg_Lot	Medium	140,000	140,000	
beach parking	Hwy Behind the Pond	40.949339	-72.17891	10,000	Pkg_Lot	Medium	50,000	50,000	
Note:	Projects > 1 MW have already been submitted are in approval queue.						Projects > 1 MW:	28,824,000	
							Projects <= 1 MW:	3,520,200	
							Total:	32,344,200	

Based on the above solar potential in the area—over 32 MW total—LICMP has the potential to far surpass the PV goals of the Community Microgrid. However, it is expected that certain sites will not achieve their proposed PV amount due to environmental considerations, such as the town not desiring a large number of trees to be removed in order to install solar. Therefore, the LICMP will propose a balanced scenario for PV that achieves the optimal solution based on the project's goals.

Energy Storage

A 5 MW/25 MWh energy storage system has already been analyzed for handling daily peak loads, e.g. during summer evenings, to be located at the East Hampton GT substation. The energy storage will also be used to mitigate variability of the solar energy during the day and to store solar energy if and when the PV output exceeds the local loads, e.g. during a sunny spring day. For the evening peak, optimization of the energy storage will use the existing SoC combined with multiple variables forecasted for the following day, including solar generation forecast, expected loads, the net amount of the forecasted solar generation minus the expected daytime load, and the Tier 2 priority load amounts that need to be maintained in reserve. In addition, the Tier 1 critical loads will be served by solar and energy storage located onsite at those facilities, as described below. The SoC management, executed by the MC^2 solution, will be a critical task that optimizes this entire energy system. The energy storage will be used whenever practically possible—to decrease the amount of diesel generation needed to satisfy the evening peaks while eliminating the need to curtail the solar energy.

Critical Facilities: Optimal PV & Energy Storage Profiles

Below are the proposed optimal PV/Energy Storage amounts per critical facility, based on the critical facility loads.

1.1.1.1 Solar Resource

Table 4 is derived from the NREL SAM program, with settings for Long Island. The output power and energy are scaled to 1 MW of PV, DC rating.

Table 4: Solar Resource Estimate by Month (NREL SAM)

Month	Daily average solar irradiance (kWh/m2/day)	AC system output (kWh/mo/ MW)	Daily Avg Output (kWh/24hr/ MW)	Days in Month
1	3.043	82,815	2,671.44	31
2	3.782	90,699	3,239.26	28
3	4.315	110,974	3,579.81	31
4	4.984	119,290	3,976.33	30
5	5.485	133,695	4,312.74	31
6	5.634	129,537	4,317.90	30
7	5.772	134,722	4,345.87	31
8	5.613	131,348	4,237.03	31
9	5.085	117,971	3,932.37	30
10	4.230	105,054	3,388.84	31
11	3.051	75,551	2,518.38	30
12	2.598	68,619	2,213.51	31

Using the December output of 2213.5 kWh/24hr/MW as a worst-case minimum, Table 5 provides estimates for minimum PV to provide 24 hours of energy. Note that the Maximum Load and Maximum Average Energy values have been rounded upwards to provide more conservative estimates for the PV sizing. These PV sizes may need to be increased further based upon the refinement of other energy storage factors such as efficiencies, energy storage chemistry needs, and limitations, etc.

Table 5: Minimum Solar Size Estimates for 24 hours of Operation in December

	Pump: Bridgehampton	Pump: Oak View	Fire Station	Totals
Max Load [kW]	200	115	35	350
Max Avg Energy [kWh/24hr]	3,000	1,500	275	4,775
PV for 24 hr in Winter [MW DC]	1.355	0.678	0.124	2.157

1.1.1.2 Minimum Solar & Energy Storage Sizing Estimates

The following tables compare the expected minimum sizes based upon worst-case minimums from the NREL solar data. Table 6 summarizes the winter & summer PV sizes needed based upon load and solar resource. Note that there is a roughly 2:1 difference in summer/winter PV resource. The result shows about twice as much PV is needed in winter vs. summer (2 vs. 1 MW). Based on this analysis, the minimum PV sizes needed to provide ongoing backup power for each of the critical site average 24 hour loads are listed below and in the table. This assumes a 20% load management reduction in emergency / backup mode:

- Bridgehampton Pump Station: 1030 kW
- Oak View Pump Station: 510 kW
- Springs Fire District: 100 kW

Table 6: Minimum Solar Sizing Estimates for Critical Loads

Minimum PV for Critical Loads	**BH Pump Station**	**OV Pump Station**	**Springs Fire District**	**Totals**	
Load Reduction in Backup Mode:				**20%**	
December Case					
Reduced Avg Daily Load [kWh/24 hr]	1,132.65	449.03	180.65	1,762.33	[kWh/24 hr]
PV needed to replenish avg 24 hr load	1.03	0.51	0.10	1.64	[MW DC]
PV output, December	2,213.51				[kWH/24 hr/MW_DC]
July Case					
Reduced Avg Daily Load [kWh/24 hr]	2,273.74	1,138.00	218.48	3,630.23	[kWh/24 hr]
PV needed to replenish avg 24 hr load	0.52	0.26	0.05	0.84	[MW DC]
PV output, July	4,345.87				[kWH/24 hr/MW_DC]

Table 7 estimates the minimum energy storage capacities needed to provide ongoing renewable operation of the loads using PV to recharge the energy storage. Calculations are completed for each critical load site for three scenarios: no PV for the first 24 hours, worst-case minimum PV, and 10th percentile PV. Three different starting SoC values (energy reserved in the storage for backup / emergency) are examined: 50%, 75%, and 25%.

The 25% SoC case is not economical; its total needs would exceed the capacity of the planned 5 MW/25 MWh central energy storage. P10 minimum PV resource assumption shows significant size decrease over no PV and minimum PV cases. It might be possible to split up some of the planned central energy storage resource into the critical load energy storage sites, but the SoC portion in reserve for the emergency backup operation would have to be added in for reliability.

Thus, the recommended energy storage sizes for the critical load facilities are listed below. Based on the above and as outlined in the following table, the recommended energy storage sizes are for Average Load with P10 PV charging at 50% SoC reserved for emergency / backup power for the July scenario—giving us the maximum storage needed to satisfy the emergency / backup power needs.

- Bridgehampton Pump Station: 7445 kWh
- Oak View Pump Station: 3726 kWh
- Springs Fire District: 715 kWh

Table 7: Minimum Energy Storage Sizing Estimates Based Upon Reserved SoC

0% Load Reduction			**Minimum Local ES Sizes for:**			
ES SoC Reserved	**Critical Load Site**	**Month**	**Avg load with no PV charging**	**Avg load with min PV charging**	**Avg load with P10 PV charging**	
50%						
	BH Pump	Dec	4,424	3,717	3,562	[kWh]
		Jul	8,882	8,522	7,445	[kWh]
	OV Pump	Dec	1,754	1,400	1,323	[kWh]
		Jul	4,445	4,265	3,726	[kWh]
	Springs	Dec	706	638	623	[kWh]
		Jul	853	819	715	[kWh]
	Total of Maximums:		14,181	13,605	11,887	[kWh]
75%						
	BH Pump	Dec	2,723	2,287	2,192	[kWh]
		Jul	5,466	5,244	4,582	[kWh]
	OV Pump	Dec	1,079	862	814	[kWh]
		Jul	2,736	2,625	2,293	[kWh]
	Springs	Dec	434	392	383	[kWh]
		Jul	525	504	440	[kWh]
	Total of Maximums:		8,727	8,373	7,315	[kWh]
25%						
	BH Pump	Dec	11,798	9,912	9,500	[kWh]
		Jul	23,685	22,724	19,855	[kWh]
	OV Pump	Dec	4,677	3,734	3,527	[kWh]
		Jul	11,854	11,373	9,937	[kWh]
	Springs	Dec	1,882	1,701	1,661	[kWh]
		Jul	2,276	2,184	1,908	[kWh]
	Total of Maximums:		37,815	36,281	31,700	[kWh]

Import from Transmission

Energy will be imported from the transmission grid at night and added to the energy storage in order to satisfy the following day's peak, as needed on an optimized basis. Thus, the amount of energy imported from the transmission grid at night will be calculated based on the SoC from the current day's net solar + load result, plus the forecasts for the next day across solar and loads, plus the amount of energy required in reserve to satisfy the critical load minimums. For example, if the amount of energy needed to satisfy the following day's peak exceeds the above calculation, an equivalent amount of energy will be imported from the transmission grid at night, with perhaps a reasonable amount of surplus, while considering energy pricing arbitrage—utilizing available storage capacity beyond this minimum to acquire energy at lower net cost.

Appendix A: Benefit-Cost Analysis Summary Report by IEc

Site 8 – Town of East Hampton

PROJECT OVERVIEW

As part of NYSERDA's NY Prize community microgrid competition, the Town of East Hampton has proposed development of the Long Island Community Microgrid Project (LICMP), which would serve two water authority pumping stations (one at Bridgehampton and one at Oak View) and the Springs Fire District facility. In addition, the microgrid's resources would connect to two of the local utility's circuits and support service to about 100 commercial and industrial facilities and about 3,200 residential customer accounts.

The LICMP would be powered by 5 MW of new photovoltaic solar generation and 5 MW of new energy storage that would be charged by the photovoltaic systems.[1] The energy resources would be located at the three critical facility sites, with the minimum capacity required for each facility at each site. The utility plans to procure a single additional energy storage facility and one or more additional photovoltaic facilities to reach the aggregate totals of 5 MW of photovoltaic generation and 5 MW of energy storage. The LICMP is designed to be an optimized local energy system that will charge the energy storage with off-peak generation, then use the stored energy to reduce peak demand. The system as designed would have sufficient generating capacity to meet average demand for electricity from the three critical facilities during a major outage, as well as 40 percent of average electricity demand from the non-critical facilities on the utility's two connected circuits. Project consultants also indicate that the system would have the capability of providing voltage or reactive power support to the grid.

To assist with completion of the project's NY Prize Stage 1 feasibility study, IEc conducted a screening-level analysis of the project's potential costs and benefits. This report describes the results of that analysis, which is based on the methodology outlined below.

METHODOLOGY AND ASSUMPTIONS

In discussing the economic viability of microgrids, a common understanding of the basic concepts of benefit-cost analysis is essential. Chief among these are the following:

- *Costs* represent the value of resources consumed (or benefits forgone) in the production of a good or service.
- *Benefits* are impacts that have value to a firm, a household, or society in general.
- *Net benefits* are the difference between a project's benefits and costs.

[1] These resources would be added to 10 MW of photovoltaic solar generation that are planned to be constructed regardless of whether or not the proposed microgrid is developed. The benefits and costs of this 10 MW system are not considered to be part of the microgrid project, and are therefore not included in our analysis.

- Both costs and benefits must be measured relative to a common *baseline* - for a microgrid, the "without project" scenario - that describes the conditions that would prevail absent a project's development. The BCA considers only those costs and benefits that are *incremental* to the baseline

This analysis relies on an Excel-based spreadsheet model developed for NYSERDA to analyze the costs and benefits of developing microgrids in New York State. The model evaluates the economic viability of a microgrid based on the user's specification of project costs, the project's design and operating characteristics, and the facilities and services the project is designed to support. Of note, the model analyzes a discrete operating scenario specified by the user; it does not identify an optimal project design or operating strategy.

The BCA model is structured to analyze a project's costs and benefits over a 20-year operating period. The model applies conventional discounting techniques to calculate the present value of costs and benefits, employing an annual discount rate that the user specifies – in this case, seven percent.[2] It also calculates an annualized estimate of costs and benefits based on the anticipated engineering lifespan of the system's equipment. Once a project's cumulative benefits and costs have been adjusted to present values, the model calculates both the project's net benefits and the ratio of project benefits to project costs. The model also calculates the project's internal rate of return, which indicates the discount rate at which the project's costs and benefits would be equal. All monetized results are adjusted for inflation and expressed in 2014 dollars.

With respect to public expenditures, the model's purpose is to ensure that decisions to invest resources in a particular project are cost-effective; i.e., that the benefits of the investment to society will exceed its costs. Accordingly, the model examines impacts from the perspective of society as a whole and does not identify the distribution of costs and benefits among individual stakeholders (e.g., customers, utilities). When facing a choice among investments in multiple projects, the "societal cost test" guides the decision toward the investment that produces the greatest net benefit.

The BCA considers costs and benefits for three scenarios:

- Scenario 1A: No major power outages over the assumed 20-year operating period (i.e., normal operating conditions only). For this scenario, the model's default values for transmission capacity are used.
- Scenario 1B: No major power outages over the assumed 20-year operating period (i.e., normal operating conditions only). For this scenario, values related to the specific transmission capacity upgrades that would be necessary in the absence of the LICMP are used.

[2] The seven percent discount rate is consistent with the U.S. Office of Management and Budget's current estimate of the opportunity cost of capital for private investments. One exception to the use of this rate is the calculation of environmental damages. Following the New York Public Service Commission's (PSC) guidance for benefit-cost analysis, the model relies on temporal projections of the social cost of carbon (SCC), which were developed by the U.S. Environmental Protection Agency (EPA) using a three percent discount rate, to value CO_2 emissions. As the PSC notes, "The SCC is distinguishable from other measures because it operates over a very long time frame, justifying use of a low discount rate specific to its long term effects." The model also uses EPA's temporal projections of social damage values for SO_2, NO_x, and $PM_{2.5}$, and therefore also applies a three percent discount rate to the calculation of damages associated with each of those pollutants. [See: State of New York Public Service Commission. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Establishing the Benefit Cost Analysis Framework. January 21, 2016.]

- Scenario 2: The average annual duration of major power outages required for project benefits to equal costs, if benefits do not exceed costs under Scenario 1.[3,4]

RESULTS

Table 1 summarizes the estimated net benefits, benefit-cost ratios, and internal rates of return for the scenarios described above. The results indicate that the value assigned to the project's transmission capacity benefits is a key consideration in the benefit-cost assessment. When the model's default estimate of the value of transmission capacity is applied and no major power outages are assumed to occur (Scenario 1A), the analysis shows that the project's costs exceed its benefits; in order for benefits to outweigh costs, the average duration of major outages would need to equal or exceed 6.6 days per year (Scenario 2). In contrast, if the analysis uses alternate estimates of the project's transmission capacity benefits (based on the avoided costs of a specific transmission capacity augmentation project), the project's benefits would exceed its costs even in the absence of major power outages (Scenario 1B). The discussion that follows provides additional detail on these findings.

Table 1. BCA Results (Assuming 7 Percent Discount Rate)

ECONOMIC MEASURE	ASSUMED AVERAGE DURATION OF MAJOR POWER OUTAGES		
	SCENARIO 1A: 0 DAYS/YEAR	SCENARIO 1B: 0 DAYS/YEAR	SCENARIO 2: 6.6 DAYS/YEAR
Net Benefits - Present Value	-$24,700,000	$4,040,000	$277,000
Benefit-Cost Ratio	0.4	1.1	1.0
Internal Rate of Return	n/a	8.2%	6.8%

Scenarios 1A and 1B

Figure 1 and Table 2 present the detailed results of the Scenario 1A analysis, while Figure 2 and Table 3 present the detailed results of the Scenario 1B analysis.

[3] The New York State Department of Public Service (DPS) requires utilities delivering electricity in New York State to collect and regularly submit information regarding electric service interruptions. The reporting system specifies 10 cause categories: major storms; tree contacts; overloads; operating errors; equipment failures; accidents; prearranged interruptions; customers equipment; lightning; and unknown (there are an additional seven cause codes used exclusively for Consolidated Edison's underground network system). Reliability metrics can be calculated in two ways: including all outages, which indicates the actual experience of a utility's customers; and excluding outages caused by major storms, which is more indicative of the frequency and duration of outages within the utility's control. In estimating the reliability benefits of a microgrid, the BCA employs metrics that exclude outages caused by major storms. The BCA classifies outages caused by major storms or other events beyond a utility's control as "major power outages," and evaluates the benefits of avoiding such outages separately.

[4] Because benefits exceed costs under Scenario 1B, Scenario 2 is run using the model's default values for transmission capacity benefits.

Figure 1. Present Value Results, Scenario 1A (No Major Power Outages; Default Transmission Capacity Benefit Values; 7 Percent Discount Rate)

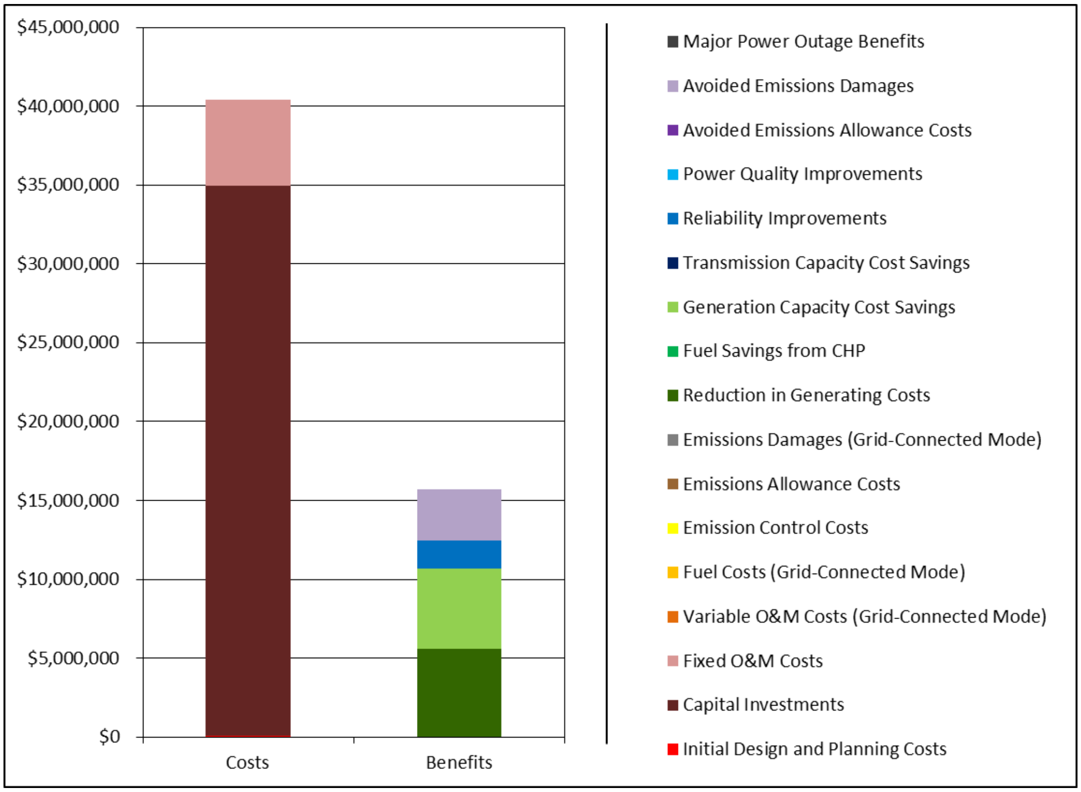


Table 2. Detailed BCA Results, Scenario 1A (No Major Power Outages; Default Transmission Capacity Benefit Values; 7 Percent Discount Rate)

COST OR BENEFIT CATEGORY	PRESENT VALUE OVER 20 YEARS (2014$)	ANNUALIZED VALUE (2014$)
Costs		
Initial Design and Planning	$60,000	$5,290
Capital Investments	$34,900,000	$2,940,000
Fixed O&M	$5,470,000	$483,000
Variable O&M (Grid-Connected Mode)	$0	$0
Fuel (Grid-Connected Mode)	$0	$0
Emission Control	$0	$0
Emissions Allowances	$0	$0
Emissions Damages (Grid-Connected Mode)	$0	$0
Total Costs	**$40,400,000**	
Benefits		
Reduction in Generating Costs	$5,580,000	$492,000
Fuel Savings from CHP	$0	$0
Generation Capacity Cost Savings	$5,100,000	$450,000
Transmission & Distribution Capacity Cost Savings	$0	$0
Reliability Improvements	$1,770,000	$156,000
Power Quality Improvements	$0	$0
Avoided Emissions Allowance Costs	$2,200	$195
Avoided Emissions Damages	$3,280,000	$214,000
Major Power Outage Benefits	$0	$0
Total Benefits	**$15,700,000**	
Net Benefits	**-$24,700,000**	
Benefit/Cost Ratio	**0.4**	
Internal Rate of Return	**n/a**	

Figure 2. Present Value Results, Scenario 1B (No Major Power Outages; Avoided Transmission Capacity Upgrade Benefit Values; 7 Percent Discount Rate)

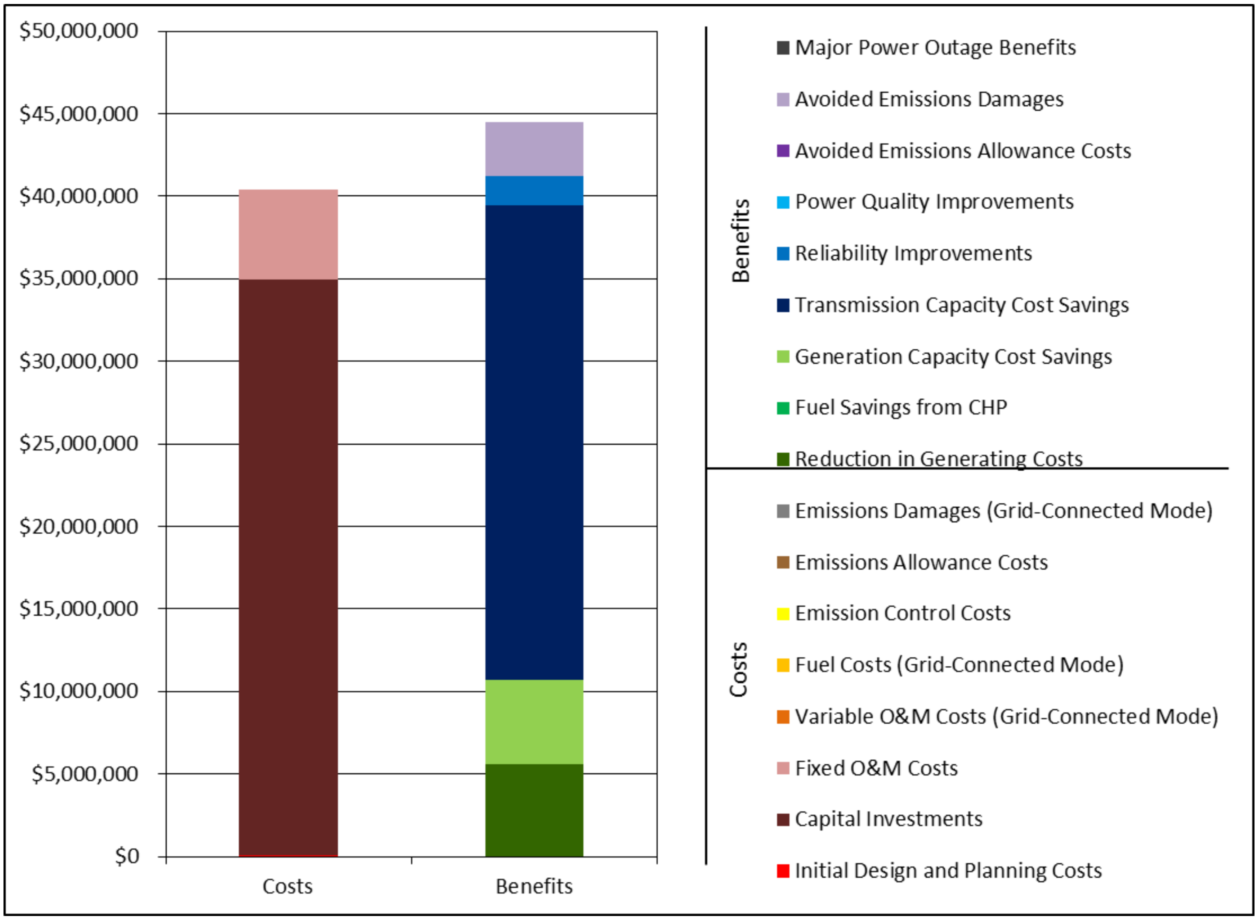


Table 3. Detailed BCA Results, Scenario 1B (No Major Power Outages; Avoided Transmission Capacity Upgrade Benefit Values; 7 Percent Discount Rate)

COST OR BENEFIT CATEGORY	PRESENT VALUE OVER 20 YEARS (2014$)	ANNUALIZED VALUE (2014$)
Costs		
Initial Design and Planning	$60,000	$5,290
Capital Investments	$34,900,000	$2,940,000
Fixed O&M	$5,470,000	$483,000
Variable O&M (Grid-Connected Mode)	$0	$0
Fuel (Grid-Connected Mode)	$0	$0
Emission Control	$0	$0
Emissions Allowances	$0	$0
Emissions Damages (Grid-Connected Mode)	$0	$0
Total Costs	**$40,400,000**	
Benefits		
Reduction in Generating Costs	$5,580,000	$492,000
Fuel Savings from CHP	$0	$0
Generation Capacity Cost Savings	$5,100,000	$450,000
Transmission & Distribution Capacity Cost Savings	$28,700,000	$2,540,000
Reliability Improvements	$1,770,000	$156,000
Power Quality Improvements	$0	$0
Avoided Emissions Allowance Costs	$2,200	$195
Avoided Emissions Damages	$3,280,000	$214,000
Major Power Outage Benefits	$0	$0
Total Benefits	**$44,500,000**	
Net Benefits	**$4,040,000**	
Benefit/Cost Ratio	**1.1**	
Internal Rate of Return	**8.2%**	

Fixed Costs

The BCA relies on information provided by the project team to estimate the fixed costs of developing the microgrid. The project team's best estimate of initial design and planning costs is approximately $60,000, which includes the costs of developing a request for offers as well as development permits for four sites. The present value of the project's capital costs is estimated at approximately $34.9 million, including the total installed capital costs associated with 5 MW of photovoltaic solar generation and 5 MW of energy storage capacity at four locations.[5] These costs also include monitoring, communication, and control systems, grid hardening at critical facilities, and interconnection of energy storage. It is worth noting that the energy storage included in LICMP allows for the addition of the 5 MW of photovoltaic solar generation

[5] The project team has indicated that the photovoltaic solar generation will be developed by a third party that will sell electricity to the local utility. Because this analysis considers societal costs, it includes an estimate of the capital costs that would be incurred by the third party to develop the photovoltaic generation. It ignores the payments that would be made by the utility for the electricity generated by the system; the value of this electricity is accounted for in the analysis of the project's benefits.

without additional distribution capacity upgrades, which helps to reduce the overall capital costs of the project.

Operation and maintenance (O&M) of the entire system, including monitoring and maintenance of energy storage, inverter replacement, and annual IT maintenance of control systems and software, would have an annual cost of approximately $483,000. The present value of these O&M costs over a 20-year operating period is approximately $5.5 million.

Variable Costs

The BCA's analysis of variable costs considers the costs of any fuel required to run the microgrid's distributed energy resources. Because the distributed energy resources that would serve the proposed project are either photovoltaic solar or energy storage, there are no fuel costs associated with the microgrid.

The analysis of variable costs also considers the environmental damages associated with pollutant emissions from the distributed energy resources that serve the microgrid, based on the operating scenario and emissions rates provided by the project team. In this case, the LICMP's distributed energy resources would emit no pollutants, and thus cause no incremental environmental damage.

Avoided Costs

The development and operation of a microgrid may avoid or reduce a number of costs that otherwise would be incurred. In the case of the LICMP, these cost savings include a reduction in demand for electricity from bulk energy suppliers and avoiding or deferring the need to invest in expansion of the conventional grid's energy generation and transmission capacity. The BCA estimates the present value of savings from reduced electricity demand over a 20-year operating period to be approximately $5.6 million; this estimate assumes the microgrid conducts energy arbitrage to offset electricity demand during peak periods, consistent with the operating profile upon which the analysis is based. The reduction in demand for electricity from bulk energy suppliers would also reduce emissions of CO_2 and particulate matter from these sources, and produce a shift in demand for SO_2 and NO_x emissions allowances. The present value of these benefits is approximately $3.3 million.[6]

Based on standard capacity factors for solar generators and storage (20 percent of total generating capacity for photovoltaic solar generators and 100 percent of total generating capacity for storage), the project team estimates the project's impact on demand for generating capacity to be approximately 6 MW per year. Based on this figure, the BCA estimates the present value of the project's generating capacity benefits to be approximately $5.1 million over a 20-year operating period. The LICMP is also expected to reduce demand for transmission capacity by 6 MW per year. As a default, the BCA model does not estimate avoided transmission capacity costs separately from avoided generation costs and generating capacity costs, because these two costs as estimated by NYISO vary by location to reflect costs imposed by location-specific transmission constraints. For the LICMP, however, the project team estimates that the project would contribute to avoiding a specific transmission capacity augmentation project, which

[6] Following the New York Public Service Commission's (PSC) guidance for benefit-cost analysis, the model values emissions of CO_2 using the social cost of carbon (SCC) developed by the U.S. Environmental Protection Agency (EPA). [See: State of New York Public Service Commission. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Establishing the Benefit Cost Analysis Framework. January 21, 2016.] Because emissions of SO_2 and NO_x from bulk energy suppliers are capped and subject to emissions allowance requirements in New York, the model values these emissions based on projected allowance prices for each pollutant.

would have an estimated cost of approximately $423,000 per MW-year. This analysis therefore presents estimates of the project's transmission capacity benefits using both the model's default values (as presented in Scenario 1A) and using the alternate values associated with the transmission capacity augmentation project that would be avoided by the LICMP (as presented in Scenario 1B). Using the alternate values, the present value of the project's potential transmission capacity benefits is estimated to be approximately $28.7 million.[7]

The project team has indicated that the proposed microgrid would have the capability to provide ancillary services, in the form of voltage or reactive power support, to the New York Independent System Operator (NYISO). Whether NYISO would select the project to provide these services depends on NYISO's requirements and the ability of the project to provide support at a cost lower than that of alternative sources. Based on discussions with NYISO, it is our understanding that the market for voltage or reactive power support is highly competitive, and that projects of this type would have a relatively small chance of being selected to provide support to the grid. In light of this consideration, the analysis does not attempt to quantify the potential benefits of providing this service.

1.1.1.3 Reliability Benefits

An additional benefit of the proposed microgrid would be to reduce customers' susceptibility to power outages by enabling a seamless transition from grid-connected mode to islanded mode. The analysis estimates that development of a microgrid would yield reliability benefits of approximately $156,000 per year, with a present value of $1.8 million over a 20-year operating period. This estimate is calculated using the U.S. Department of Energy's Interruption Cost Estimate (ICE) Calculator, and is based on the following indicators of the likelihood and average duration of outages in the service area:[8]

- System Average Interruption Frequency Index (SAIFI) – 0.72 events per year.
- Customer Average Interruption Duration Index (CAIDI) – 81.6 minutes.[9]

The estimate is further based on:

- U.S. Census Bureau data on the median household income within the Town of East Hampton;
- Information provided by the project team on the number of households and businesses within the area supported by the microgrid;
- New York State-specific default values from the ICE Calculator on the ratio of small to large commercial and industrial customers; the distribution of commercial and industrial customers among industries; average annual electricity usage per customer (scaled by IEc to align with the average annual aggregate load provided by the project team); and the prevalence of backup generation among customers.

The estimate of reliability benefits takes into account the capabilities of backup generation among these customers. It also takes into account the variable costs of operating existing backup generators, both in the baseline and as an integrated component of a microgrid. Under baseline conditions, the analysis

[7] We note, however, that this estimate likely overestimates the true value of the project's transmission capacity benefits because a portion of these benefits are already accounted for in the analysis's estimates of avoided generation costs and generating capacity costs.
[8] www.icecalculator.com.
[9] The analysis is based on DPS's reported 2014 SAIFI and CAIDI values for PSEG Long Island.

assumes a 15 percent failure rate for backup generators.[10] It assumes that establishment of a microgrid would reduce the rate of failure to near zero.

It is important to note that the analysis of reliability benefits assumes that development of a microgrid would insulate the facilities the project would serve from outages of the type captured in SAIFI and CAIDI values. The distribution network within the microgrid is unlikely to be wholly invulnerable to such interruptions in service. All else equal, this assumption will lead the BCA to overstate the reliability benefits the project would provide.

1.1.1.4 Summary

The analysis of Scenario 1A yields a benefit/cost ratio of 0.4; i.e., the estimate of project benefits is approximately half that of project costs. Accordingly, the analysis moves to Scenario 2, taking into account the potential benefits of a microgrid in mitigating the impact of major power outages. Because the analysis of Scenario 1B yields a benefit/cost ratio of 1.2 (meaning that the estimate of project benefits is higher than that of project costs under this scenario), the analysis of Scenario 2 is limited to a case that uses the model's default values for transmission capacity, rather than the alternate transmission capacity benefit values incorporated into Scenario 1B.

Scenario 2

1.1.1.5 Benefits in the Event of a Major Power Outage

As previously noted, the estimate of reliability benefits presented in Scenario 1 does not include the benefits of maintaining service during outages caused by major storm events or other factors generally considered beyond the control of the local utility. These types of outages can affect a broad area and may require an extended period of time to rectify. To estimate the benefits of a microgrid in the event of such outages, the BCA methodology is designed to assess the impact of a total loss of power – including plausible assumptions about the failure of backup generation – on the facilities the microgrid would serve. It calculates the economic damages that development of a microgrid would avoid based on (1) the incremental cost of potential emergency measures that would be required in the event of a prolonged outage, and (2) the value of the services that would be lost.[11,12]

As noted above, the LICMP would serve three critical facilities: two water authority pumping stations and the Springs Fire District facility. The project's consultants indicate that at present, all three facilities are equipped with backup generators that can support the full level of service at each facility. Operation of these units costs approximately $560 per day. Should these units fail, the pumping stations and fire district facility could maintain operations by bringing in portable diesel generators with sufficient power to maintain all services. Hooking up these units would cost approximately $1,500, and their operation would cost $2,200 per day. In the absence of backup power – i.e., if the backup generator failed and no replacement was available – the pumping stations would experience a complete loss in service capabilities, while the fire district facility would experience a 40 percent loss in service capabilities.

[10] http://www.businessweek.com/articles/2012-12-04/how-to-keep-a-generator-running-when-you-lose-power#p1.

[11] The methodology used to estimate the value of lost services was developed by the Federal Emergency Management Agency (FEMA) for use in administering its Hazard Mitigation Grant Program. See: FEMA Benefit-Cost Analysis Re-Engineering (BCAR): Development of Standard Economic Values, Version 4.0. May 2011.

[12] As with the analysis of reliability benefits, the analysis of major power outage benefits assumes that development of a microgrid would insulate the facilities the project would serve from all outages. The distribution network within the microgrid is unlikely to be wholly invulnerable to service interruptions. All else equal, this will lead the BCA to overstate the benefits the project would provide.

The information provided above serves as a baseline for evaluating the benefits of developing a microgrid. Specifically, the assessment of Scenario 2 makes the following assumptions to characterize the impacts of a major power outage in the absence of a microgrid:

- The water authority pumping stations would rely on their existing backup generators, experiencing no loss in service capabilities while the generator operates. If the backup generator fails, the pumping stations would experience a total loss of service.
- The Springs Fire District facility would rely on its existing backup generator, experiencing no loss in service capabilities while the generator operates. If the backup generator fails, the fire district facility would experience a 40% loss in service.
- In all three cases, the supply of fuel necessary to operate the backup generator would be maintained indefinitely.
- At each facility, there is a 15 percent chance that the backup generator would fail.

In addition to these three critical facilities, the LICMP would also provide power to a large portion of the town of East Hampton's residential and commercial electricity customers, comprising about 100 commercial and industrial facilities and about 3,200 residential customer accounts. The assessment of Scenario 2 assumes that in the absence of a microgrid, about 20 percent of these accounts would be able to support themselves during a major power outage with existing backup generation capabilities. With the microgrid in place, the project team estimates that about 40 percent of these accounts would be supported, for a marginal improvement of 20 percent.

The economic consequences of a major power outage also depend on the value of the services the facilities of interest provide. The analysis calculates the impact of a loss in the town's fire services using standard FEMA values for the costs of fires, the baseline incidence of fires per capita, and the impact of changes in fire service effectiveness on damages from fires. For the water services provided by the pumping stations, the analysis calculates the impact of a loss of service using per-capita estimates of the welfare benefit of maintaining residential water services, as well as the average economic benefit of maintaining water services to commercial and industrial customers. For the 100 commercial and industrial facilities and 3,200 residential facilities that the LICMP would provide partial service, the analysis uses the ICE Calculator to estimate the total value of preventing an eight-hour outage at these facilities (representing the average length of time that these accounts would draw from the microgrid during a single day).

Based on these values, the analysis estimates that in the absence of a microgrid, the average cost of an outage for the facilities of interest is approximately $334,000 per day.

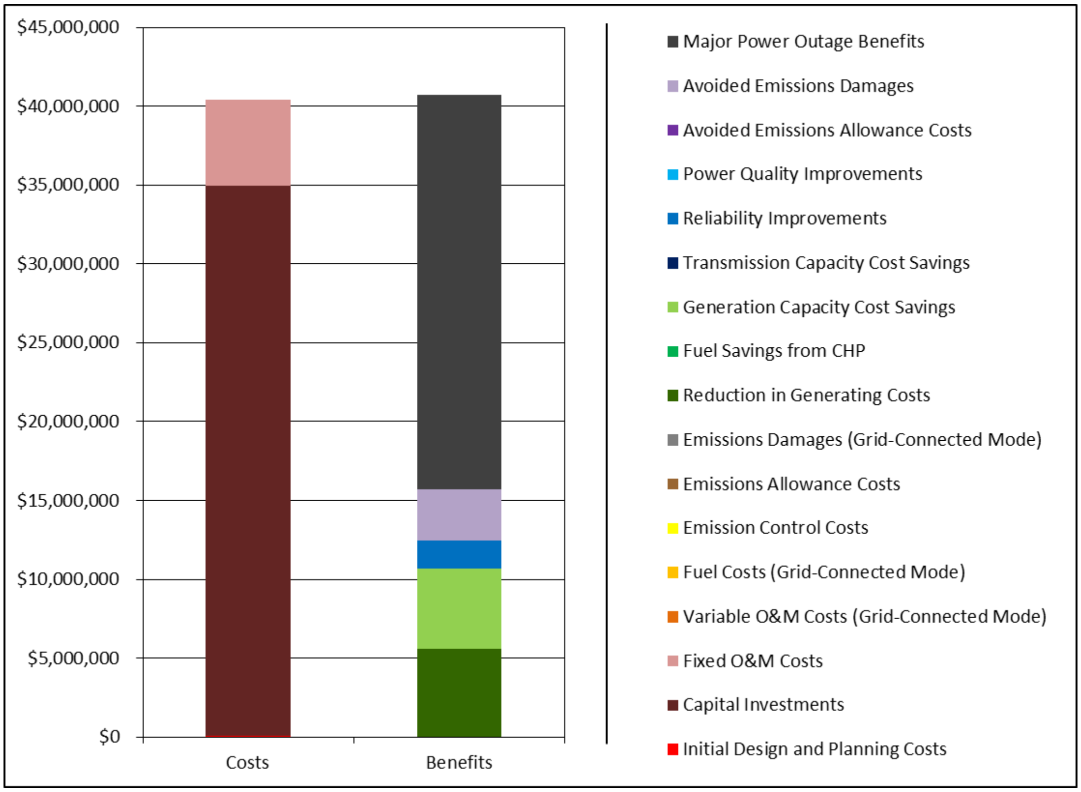
1.1.1.6 Summary

Figure 3 and Table 4 present the results of the BCA for Scenario 2 based on the values applied in Scenario 1A. The results indicate that the benefits of the proposed project would equal or exceed its costs if the project enabled the facilities it would serve to avoid an average of 6.6 days per year without power.[13] If the average annual duration of the outages the microgrid prevents is less than this figure, its

[13] This estimate assumes implicitly that the microgrid would be able to provide the necessary power to all supported facilities for this time period. The project team estimates that the photovoltaic solar distributed energy resources would be able to provide an average of 17.8 MWh per day during a major power outage, while the energy storage unit would be able to provide 25 MWh if it were fully charged at the time the major power outage occurred. Together, these two resources would be able to provide

costs are projected to exceed its benefits. Using the project-specific values applied in Scenario 1B, which achieves a benefit cost ratio of 1.1, the benefits of the proposed project exceed its costs even if no major power outages occur.

Figure 3. Present Value Results, Scenario 2 (Major Power Outages Averaging 6.6 Days/Year; 7 Percent Discount Rate)



about 22.8 MWh per day over the course of a five-day outage. The BCA estimates that the supported facilities would require about 27.3 MWh per day, suggesting that the LICMP would fall short of the facilities' needs without relying on existing backup generators.

Table 4. Detailed BCA Results, Scenario 2 (Major Power Outages Averaging 6.6 Days/Year; 7 Percent Discount Rate)

COST OR BENEFIT CATEGORY	PRESENT VALUE OVER 20 YEARS (2014$)	ANNUALIZED VALUE (2014$)
Costs		
Initial Design and Planning	$60,000	$5,290
Capital Investments	$34,900,000	$2,940,000
Fixed O&M	$5,470,000	$483,000
Variable O&M (Grid-Connected Mode)	$0	$0
Fuel (Grid-Connected Mode)	$0	$0
Emission Control	$0	$0
Emissions Allowances	$0	$0
Emissions Damages (Grid-Connected Mode)	$0	$0
Total Costs	**$40,400,000**	
Benefits		
Reduction in Generating Costs	$5,580,000	$492,000
Fuel Savings from CHP	$0	$0
Generation Capacity Cost Savings	$5,100,000	$450,000
Transmission & Distribution Capacity Cost Savings	$0	$0
Reliability Improvements	$1,770,000	$156,000
Power Quality Improvements	$0	$0
Avoided Emissions Allowance Costs	$2,200	$195
Avoided Emissions Damages	$3,280,000	$214,000
Major Power Outage Benefits	$25,000,000	$2,200,000
Total Benefits	**$40,700,000**	
Net Benefits	**$277,000**	
Benefit/Cost Ratio	**1.0**	
Internal Rate of Return	**6.8%**	

Appendix B: Clean Coalition Benefit Cost Analysis

Below is the complete benefit cost analysis of the as designed LICMP covering all the relevant financial aspects and other variables. Highlights of this cost-benefit analysis include:

- The LICMP will avoid $29-38 million of new, local transmission capacity resulting in an immediate net cost benefit for all PSEG LI utility ratepayers.
- The local generation capacity provided by the LICMP solar and energy storage facilities will reduce NYISO capacity charges by $6 million through 2022, and at a rate exceeding $1 million annually thereafter.
- The energy storage will allow the utility to shift wholesale power purchases from daily peak pricing periods to off-peak periods, realizing net savings in energy purchases of $2.5 million by 2022 and more than $500,000 annually thereafter.
- Savings for all PSEG LI utility customers from the start and ongoing.
- Over $32 million in local wages and other economic value from project construction; and additional local economic stimulation ongoing.
- The value of avoiding loss of local electrical power to the community served by the LICMP circuits estimated by the NYSERDA Independent Evaluator at $334,000 per day of avoided outage.

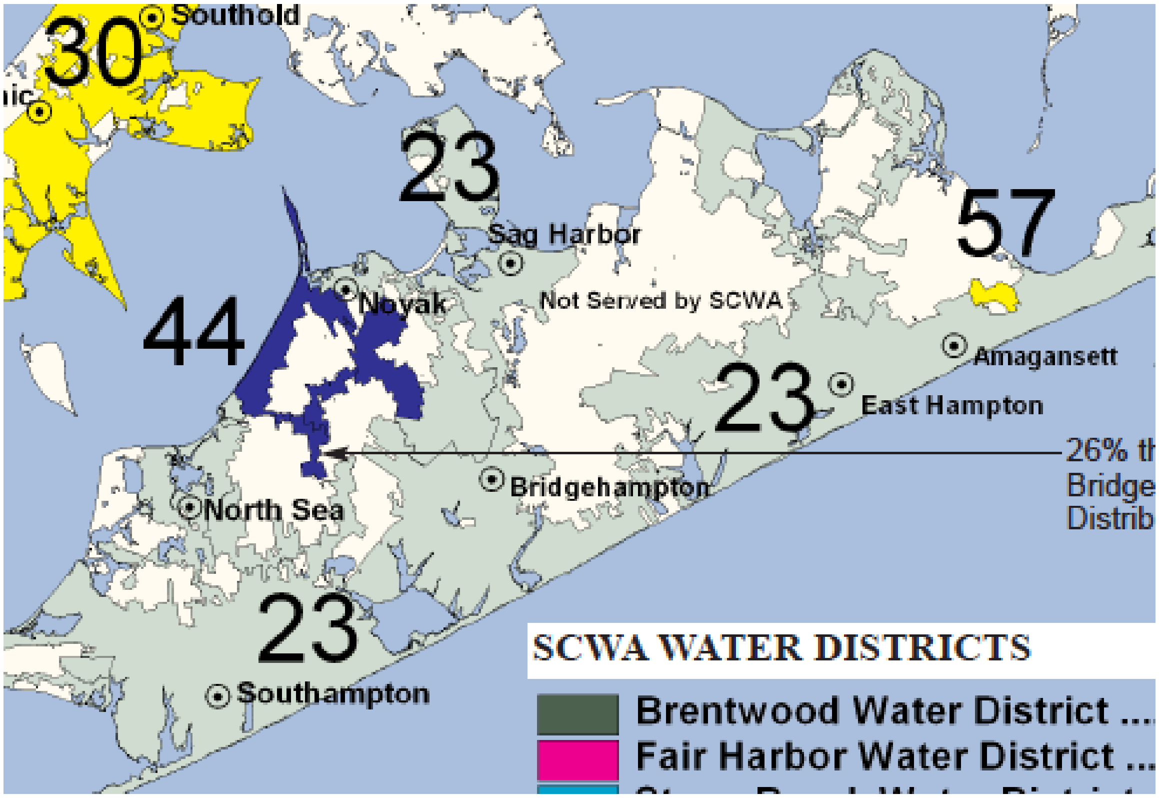
Customers Associated with Critical Loads

The LICMP will directly cover roughly 10,000 residents and employees across 3,343 utility customer accounts. Tens of thousands more will receive benefits from the capability of the LICMP to island critical facilities that serve the entire East End region during power outages.

Two SCWA pumping stations and one local fire station in Springs are the identified critical loads served by the proposed community microgrid project. In the event of a regional or local power outage the microgrid would maintain service to these loads, in addition to potential additional emergency electrical service to prioritized customers connected to the substation bank.

The Springs Fire Department serves a population of 6,600. The two pumping stations supply 11% of the total summertime water load to SCWA Distribution Area 23 (see Figure 14), which supports 21,084 customer accounts associated with a local population of approximately 41,644, based on US Census data, including a small percentage not served by SCWA. The two pumping stations locally serve East Hampton and Amagansett with a population of 6,400; however these stations are networked to the entire Distribution Area 23 and would be capable of supplying all or nearly all of the emergency water requirements for the Distribution Area population during emergency periods when consumption would be restricted to limited indoor use.

Figure 14: SCWA Water District 23 Map



Service Benefits

Peak Load and Generation Management

The proposed PV generation and energy storage facilities will be used in coordination to manage peak generation and load within the LICMP area and the South Fork transmission branch. The 5MW battery will absorb generation in excess of coincident local demand, allowing a 50% increase in PV generating capacity to be sited on the supported circuits. The 15 MW of PV incorporated in the LICMP service area, including the additional 5 MW of PV supported by the addition of storage, reduce local peak transmission load by 3MW at a conservatively estimated net effective capacity value of 20% during peak transmission periods. The 25 MWh of storage is rated at 5 MW effective capacity during this same period, for a combined total of 8 MW of load management.

Energy Sales

The 15 MW of PV incorporated in the LICMP service area, including the additional 5 MW of PV supported by the addition of storage to the Community Microgrid project on these two circuits, will supply nearly 50% of the total annual energy consumed in the Community Microgrid area, serving more than 3,300 customers comprised of roughly 10,000 residents and employees.

As the LICMP is integrated with local utility operations, it will not directly impact total energy sales to customers during ordinary operation. The preservation of service to critical facilities and priority loads during local or system outages will result in energy sales to these facilities that would otherwise have been lost, and preservation of critical services is of high importance. The monetary value of these sales, however, is not significant since it will only occur during system outage periods.

Reduced costs of meeting local capacity, reliability, resiliency and renewable goals will marginally reduce the total cost of energy for customers throughout the service territory, but reductions in overall utility tariff rates will only be noticeable if the project is replicated to utility scale within the Long Island service territory.

Reliability and Resiliency

In the advent of a transmission level outage that would otherwise result in loss of power on Bank 2 of the substation and the two target electrical circuits, the proposed LICMP system will be able to maintain service to the critical loads for an indefinite period of time. In addition, the LICMP system can maintain ongoing service to additional selected priority loads, relying solely on the central energy storage capacity and extended during solar generation hours (see Solution Profile section for more details). The value of avoiding loss of local electrical power to the community served by the LICMP circuits has been estimated at $334,000 per day by the NYSERDA Independent Evaluator, as described in their separate report. This includes continuous provision of power to the local critical facilities as well as additional power to priority loads throughout the community.

In the advent of a local distribution level outage disrupting delivery of power to local loads, critical loads will remain fully supported in isolated operation through locally hardened dedicated circuits associated with resources scaled to critical load requirements.

Costs

The total installed capital and service cost for 5 MW/25 MWh capacity battery systems over a 20-year period is on the order of $20 million. The RFP will evaluate the initial capital costs relative to the lifecycle costs and efficiency over the planned operation for the optimal benefit/cost ratio.

Costs associated with local distribution system communications modernization to accommodate planned PV, storage, and islanding for critical load service will be determined based upon final siting plans and operational requirements but are not anticipated to exceed $2 million for the scope of the planned installations. An additional $3 million in hardware/grid upgrade costs is expected in order to support the project, specifically to enable the advanced monitoring, communications, and control solution.

The planned PV capacity serves the Community Microgrid but is owned by independent energy suppliers. The locally produced energy is sold through competitive bid to the utility to meet both local and general portfolio procurement needs. The LICMP manages local generation but is served by undifferentiated utility sources unless operating in emergency mode—there is no dedicated LICMP procurement cost.

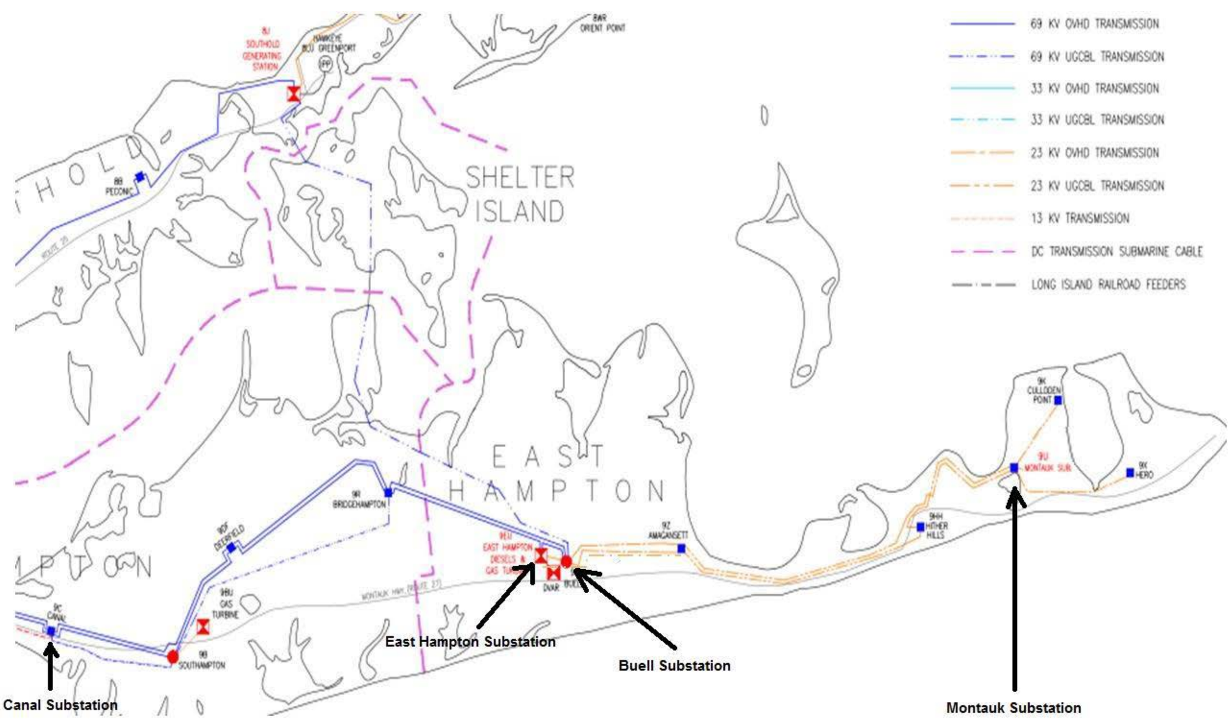
Deferred Investments in Transmission Upgrades

Note: In this section, the transmission reinforcement costs, incremental avoided costs, and load growth estimates were provided directly by utility staff and are also in PSEG LI's Utility 44 Long Range Plan released July 1, 2014[14].

Peak electrical needs in the South Fork of Long Island are projected to grow[15]. Meeting this demand with conventional transmission reinforcements is estimated to cost around $300 million by 2022. PSEG LI's recent RFP for South Fork Resources succinctly describes the issue[16]:

The portion of the transmission and distribution (T&D) System on the South Fork of Long Island is a peninsular, semi-isolated load pocket with highly constrained transmission capabilities connecting this load pocket with the remainder of the T&D System. For purposes of planning, this load pocket can be subdivided into three subareas (see Figure 15). One area comprises the loads served East of the Canal substation; the next subarea comprises all loads served by the substations east of Buell, including the East Hampton, Buell and Amagansett substations; and the third subarea comprises the loads east of Amagansett, that are served by the Culloden Point, Hero, Hither Hills, and Montauk substations.

Figure 15: Transmission Map of the South Fork



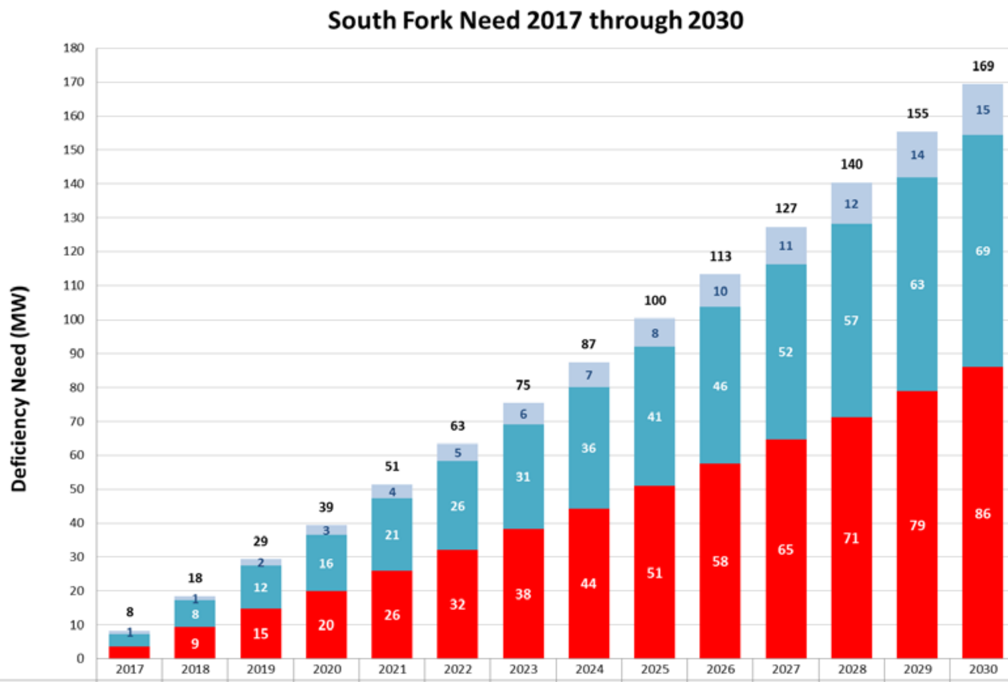
The peak load on the South Fork is projected to be 314 MW in 2019, and increase at a 2.6% average annual growth rate to 341 MW in 2022. The peak load of the subarea east of Buell is projected to be 41

[14] PSEG LI Utility 2.0 Long Range Plan, July 1, 2014
[15] PSEG LI Request for Proposals, South Fork Resources, 2015
[16] ibid

MW in 2019, and grow to 54 MW in 2030. If this peak load growth were to occur without the addition of local resources (i.e. Load Reduction and/or Power Production) in the load pocket, new transmission lines would need to be built.

Figure 16 below illustrates the South Fork power resource (MW) deficiency need for the years 2017 through 2030. The chart highlights the total resource need by year and segments it by the local requirements as needed to address the various constraints on the South Fork.

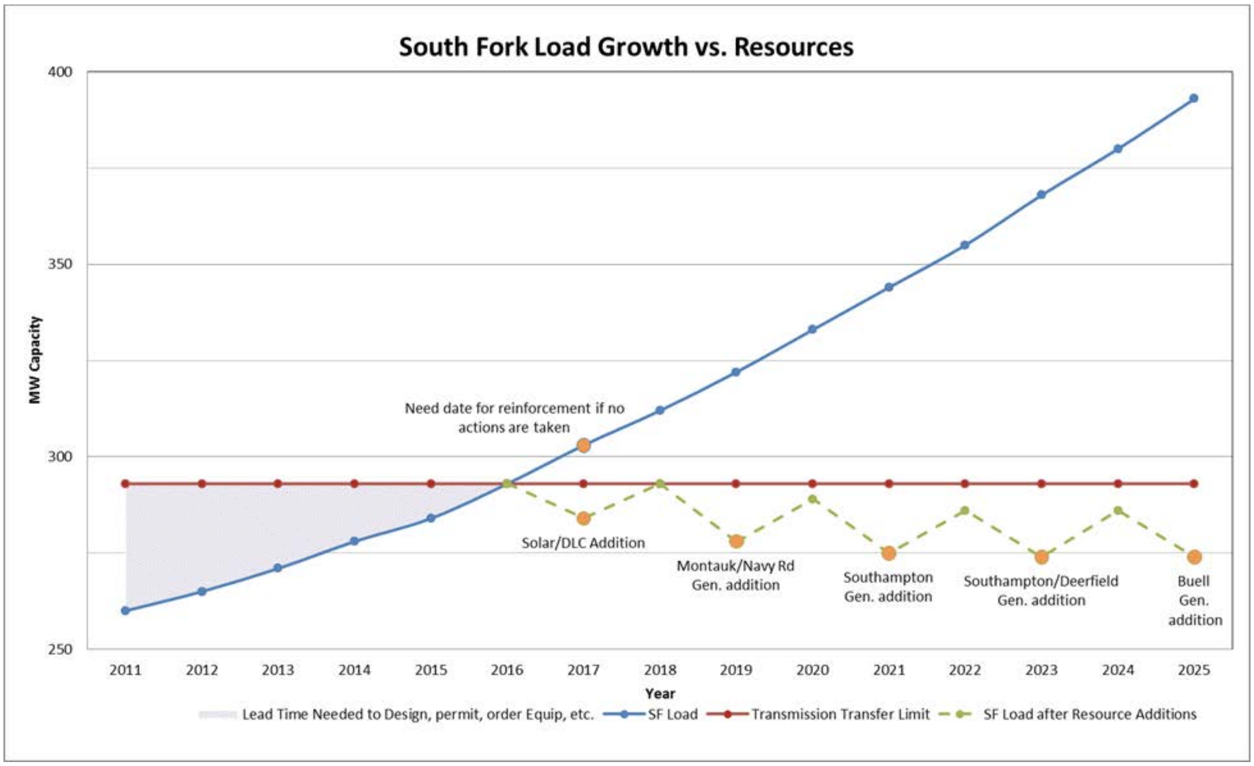
Figure 16: South Fork Projected Power Needs through 2030



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Need E/O Amagansett Only	1	1	2	3	4	5	6	7	8	10	11	12	14	15
Need at Buell/E. Hampton or East	4	8	12	16	21	26	31	36	41	46	52	57	63	69
Need E/O Canal	4	9	15	20	26	32	38	44	51	58	65	71	79	86
Total SF Need	8	18	29	39	51	63	75	87	100	113	127	140	155	169

As part of its Utility 2.0 plan, PSEG LI will defer the need for transmission reinforcements by a combination of expanded EE, direct load control, local generation, and energy storage. Figure 17 below details the timing of the planned Utility 2.0 resources. The transmission upgrades required to meet the projected 63 MW deficiency in the South Fork through 2022 have been estimated by the utility to cost approximately $300 Million. On this basis the incremental avoided cost value of transmission alternatives within this local area is established at $4.79 million per MW of effective peak capacity, and the utility is proceeding to acquire sufficient cost effective local resources to meet these expected peak load requirements. In addition, the Utility 2.0 Plan addresses all three of PSEG Long Island's resiliency efforts by improving prevention, survivability and recovery. Results of this proposal will provide information to guide similar design solutions that are being considered across Long Island as deemed applicable and cost effective.

Figure 17: South Fork Load Growth & Utility 2.0 Resource Plan



Energy Storage capacity fully offsets the transmission capacity deficiency on a 1:1 net effective capacity basis. A 5 MW/25 MWh battery, as proposed in the LICMP, will therefore directly contribute 5 MW toward peak transmission load reduction, a value of $23.8 million as a portion of the total avoided transmission cost.

Photovoltaic resources, due to the mismatch between their generation profile and the peak load profile in this area, offer a lower effective capacity that we have conservatively estimated at 20% (1:5). The LICMP will incorporate 10 MW of PV already planned for these circuits, contributing 2 MW to peak transmission load reduction. This is valued at $9.5 million as a portion of the total avoided transmission cost.

The inclusion of a 5 MW/25 MWh battery as part of the LICMP will allow a higher penetration of PV on the LICMP circuits. The additional 5 MW of PV provides 1 MW of transmission capacity offset, avoiding an additional $4.8 million in transmission costs.

The total avoided cost of the LICMP is estimated to be $38 million, of which approximately $24 million is directly attributable to the planned energy storage capacity and $14 million from additional solar generation on the LICMP grid.

Capacity Charge Savings

The 5 MW/25 MWh energy storage facilities will also reduce NYISO capacity charges by $3.2 million through 2022 (see Table 8), and by more than $700,000 the following year, escalating annually thereafter. The 15 MW of PV will contribute $2.8 million in reduced NYISO capacity charges in the same period, more than $500,000 the following year, and likewise escalating at the same rate thereafter. A detailed breakdown of this analysis can be found in the Capacity Cost Savings section of Appendix C below.

Table 8: Market Capacity Cost Savings

Year	2016	2017	2018	2019	2020	2021	2022
Storage value (x1000)	$235	$345	$434	$494	$519	$562	$649
15 MW PV value (x1000)	$254	$291	$375	$423	$450	$477	$506

Energy Arbitrage Savings

NYISO hourly Location Bus Marginal Price (LBMP) rates for LIPA demonstrate the potential arbitrage savings achieved from utilizing the energy storage capacity to purchase transmission power during the five consecutive lowest price hours, thereby avoiding purchasing 25 MWh during the five consecutive highest priced hours of the day. Estimated realized savings must account for a 30% net round-trip energy loss from the from the battery storage facilities. Based on 2014 and 2015 actual pricing data the net annual arbitrage value would have been $240,000 per year.

NYISO projected hourly energy tables through 2022 indicate annual energy savings arbitrage value increasing at a rate between 12% and 20% per year[17]. Applying the lower 12% rate of increase, Table 9 estimates the annual arbitrage value, yielding a total of approximately $2.5 million from 2017 through 2022.

Table 9: Annual Energy Arbitrage Value from Storage

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy Value (x1000)	$244	$235	$269	$301	$337	$378	$423	$474	$531

In actual practice the savings will be greater if the purchases and energy avoided is optimized for non-consecutive hours, also potentially allowing more than 25 MWh of energy charging and discharging during any 24 hour period.[18]

Regional Economic Impacts

Economic and employment impacts were estimated utilizing the NREL Jobs & Economic Development Indicator (JEDI) analysis[19]. The development of 15 MW of PV within the LICMP is estimated to require 200 full time equivalent job years in employment in the local region during the construction phase, producing $15.5 million in wages, and a total economic output value of $28.4 million. These figures do

[17] The rate of increase in the value of the difference between the high cost and low cost hours is 20% annually when losses are accounted for due to the increasing degree of difference between peak and minimum energy costs, however we adopt the lower figure to avoid overstating the growth in arbitrage value when extrapolating based on cost projections.

[18] NYISO hourly pricing projections for future years reflect average pricing and do not account for the actual variability observed between hours that would be subject to arbitrage.

[19] See Appendix G for the detailed JEDI data

not include any value associated with the manufacture of equipment in the state or region. Following construction, ongoing operations will yield and additional $258,000 annually in local wages, totaling 78 total job years of employment for $5.2 million over the first 20 years of operational life.

Development and installation of the proposed 5 MW/25 MWh of energy storage facilities is initially estimated to result in 30 total job years of employment, $2.3 million in salary and wages, and $4.1 million in total economic output value. These figures do not include any value associated with the manufacture of the storage systems or associated equipment in the state or region. Following construction, ongoing operations will yield and additional $86,000 annually in local wages, totaling $1.7 million over the first 20 years of operational life. These figures are preliminary and may vary substantially depending on the storage technology selected.

Utility work required for the interconnection of the generation and storage facilities is included in the employment and economic impact analysis for these facilities. Addition utility investment in grid modernization including communications and control systems has not yet been assessed, but may be anticipated to result in additional economic effects of the total LICMP project in the range of 5%.

Wages will result in addition public revenues from income taxes, sales taxes related to induced household spending, and reduced public benefits costs that are not included in the NREL analysis. PV site leasing at a rate of $10,000 per MW per year adds an additional $150,000 annual income value to properties owners in the LICMP service area, totaling $3 million over the first 20 years of operational life.

This project does not rely on investment from the community beyond that of the regional utility and independent energy providers. Net costs and benefits realized by the utility will be reflected in electric rates.

Appendix C: Supporting Data for BCA

Capacity Cost Savings

Table 10 and Table 11 below show capacity cost savings for 5MW Storage plus 15MW PV (10 + 5).

Table 10: LIPA Capacity (UCAP) Savings, Battery Supply Side

LIPA Capacity Costs - 5 MW/25 MWh Battery Supply Side					
Year	ROS UCAP Annual Prices	LHV UCAP Annual Prices	Zone 'K' UCAP Annual Prices	Net Market Capacity Costs	Project Savings
	$/kw-yr	$/kw-yr	$/kw-yr	$ millions	$
2015	$37.43	$74.66	$52.55	$24.5	$0
2016	$37.36	$42.95	$52.51	$26.8	$235,356
2017	$37.90	$37.90	$52.77	$31.4	$345,001
2018	$39.01	$39.01	$52.67	$42.4	$433,575
2019	$39.82	$39.82	$54.68	$50.3	$493,671
2020	$40.73	$40.73	$56.73	$54.0	$519,402
2021	$42.38	$42.38	$64.86	$65.2	$561,513
2022	$44.89	$44.89	$74.30	$75.9	$649,496
					$3,238,148

Table 11: LIPA Capacity (UCAP) Savings, Solar Supply Side

LIPA Capacity Costs - 15 MW Solar Supply Side					
Year	ROS UCAP Annual Prices	LHV UCAP Annual Prices	Zone 'K' UCAP Annual Prices	Net Market Capacity Costs	Project Savings
	$/kw-yr	$/kw-yr	$/kw-yr	$ millions	$
2015	$37.43	$74.66	$52.55	$24.5	$0
2016	$37.36	$42.95	$52.48	$26.8	$253,748
2017	$37.90	$37.90	$52.88	$31.4	$291,353
2018	$39.01	$39.01	$52.73	$42.4	$374,586
2019	$39.82	$39.82	$54.75	$50.4	$424,739
2020	$40.74	$40.74	$56.80	$54.0	$449,691
2021	$42.37	$42.37	$64.94	$65.2	$476,899
2022	$44.88	$44.88	$74.46	$76.0	$506,287
					$2,777,073

Detailed JEDI Analysis Results

The LICMP Feasibility Analysis separately considers regional economic factors and reports the results of an NREL Jobs and Economic Development Indicator (JEDI) 20-year analysis. This impact analysis focuses on work occurring locally, primarily the design, installation and operation, and excludes expenditures associated with the manufacture of the PV modules and modular battery systems which occur outside of the economic region. JEDI is designed primarily for consideration of renewable energy generation projects, and the energy storage component of LICMP is not included as these impact estimates are not reliably available. The Community Microgrid project will incorporate 15 MW of PV, including 5 MW that would not be installed without the Community Microgrid.

This project is estimated to result in at least 278 job years of employment from the construction and ongoing operations of the PV modules—yielding a total local economic output of $36 million, including more than $20 million in total local employment earnings, over 20 years.

Table 12: Detailed JEDI Analysis Results

Project Location	**NEW YORK**
Year of Construction or Installation	2016
Average System Size - DC Nameplate Capacity (KW)	5000
Number of Systems Installed	3
Total Project Size - DC Nameplate Capacity (KW)	15000
System Application	Utility
Solar Cell/Module Material	Crystalline Silicon
System Tracking	Single Axis
Base Installed System Cost ($/KWDC)	$2,566
Annual Direct Operations and Maintenance Cost ($/kW)	$19.93
Money Value - Current or Constant (Dollar Year)	2015
Project Construction or Installation Cost	$38,496,000
Local Spending	$17,346,000
Total Annual Operational Expenses	$4,400,053
Direct Operating and Maintenance Costs	$298,950
Local Spending	$275,034
Other Annual Costs	$4,101,103
Local Spending	$4,783
Debt Payments	$0
Property Taxes	$0

Local Economic Impacts			
	Job	Earnings	Output
During construction and installation period	Years	x$000 (2015)	x$000 (2015)
Project Development and Onsite Labor Impacts			
Construction and Installation Labor	46.3	$3,000.0	
Construction and Installation Related Services	43.1	$4,282.1	
Subtotal	89.4	$7,282.1	$10,200.0
Module and Supply Chain Impacts			
Manufacturing	0.0	$0.0	$0.0
Trade (Wholesale and Retail)	8.5	$727.6	$1,783.9
Finance, Insurance and Real Estate	0.0	$0.0	$0.0
Professional Services	6.1	$520.9	$1,152.8
Other Services	16.0	$2,528.0	$5,829.0
Other Sectors	36.9	$1,433.8	$2,340.9
Subtotal	67.4	$5,210.3	$11,106.6
Induced Impacts	42.7	$2,972.8	$7,133.7
Total Impacts	199.6	$15,465.2	$28,440.3
	Annual	Annual	Annual
	Jobs	Earnings	Output
During operating years		x$000 (2015)	x$000 (2015)
Onsite Labor Impacts			
PV Project Labor Only	2.8	$166.6	$166.6
Local Revenue and Supply Chain Impacts	0.6	$57.8	$142.3
Induced Impacts	0.5	$33.7	$80.9
Total Impacts	3.9	$258.1	$389.8

Appendix D: Comparison with NYSERDA Independent BCA

Cost Basis & Benefit Cost Ratio

The independent evaluator has recognized that this project is designed to address specific local and regional factors and completed two separate evaluations of Scenario 1: Scenarios 1a and 1b. Scenario 1b appropriately applies values that reflect regional transmission capacity constraints and the project's contribution toward the utility's preferred alternative to a $300 million transmission upgrade that would otherwise be required.

The LICMP proposers commend the efforts of the independent evaluator to develop and utilize a common approach and metrics to compare proposals and believe they are accurately applying those metrics. However, a significant question is raised regarding the approach of including optional capital investments that are not required by the Community Microgrid as societal costs attributable to the Community Microgrid. In developing benefit to cost ratios of the Community Microgrid project, the NYSERDA independent evaluator includes the cost of the additional PV facilities that are likely to be developed within the microgrid area as a result of the higher PV penetration and interconnection capacities enabled by the microgrid's energy management systems—including the storage, communication and control capabilities.

LICMP will make use of energy from 10 MW of local PV that is being deployed regardless of this Community Microgrid development, and will enable the development of an additional 5 MW of local PV capacity sought by the utility to address local capacity needs. The Community Microgrid will receive energy from the PV systems operating within the Community Microgrid perimeter during both ordinary and islanded periods, *however* these facilities are independent and not owned by the utility which will own and operate the Community Microgrid, therefore they do not represent a capital cost born by the utility or ratepayers as owners of the Community Microgrid.

The LICMP proposers believe that the impact of the Community Microgrid in increasing the ability of the distribution system to accommodate higher levels of local PV is a societal benefit, but that any costs associated with that actual development owned by third parties should be evaluated separately from evaluation of the net value of the proposed Community Microgrid owned by the utility. PV development that does occur within the LICMP perimeter is being developed by independent third parties, primarily in response to energy procurement contracts offered by the utility where such procurement is deemed cost effective. As such, the LICMP proposers do not agree that this addition of local PV resources and increased hosting capacity appropriately represents a "cost" that results in a lower benefit to cost ratio than would be reported otherwise.

The estimated $12,800,000 cost of deploying the optional additional 5 MW of third party PV capacity represents 32% of the total LICMP costs included in the NYSERDA independent evaluation approach. If this were not added to the LICMP cost basis reported in scenario 1B, the total project cost would be reduced from $40,400,000 to $27,600,000. Eliminating the 5 MW of PV would also impact benefits associated with the value of the energy generated and the 20% effective capacity value assigned to this PV, reducing total benefits by $6,600,000 for a total benefit value of $40,500,000. This would result in net benefits of $12,900,000 and a benefit/cost ratio of 1.47.

Major Power Outage Benefits (Scenario 2)

Scenario 2 analysis of benefits associated with major power outages establishes addition avoided cost value of $334,000 per day. As noted in the IEc report, the independent evaluation recognizes that LICMP is fully cost effective prior to consideration of benefits associated with major power outages, as established in Scenario 1b of the IEc report, and no avoided outage value is required for the project to achieve a positive benefit to cost ratio. As a result, the evaluation of the number of days per of avoided major power outages necessary for the Community Microgrid's benefits to exceed its costs is only applicable under Scenario 1a in which the avoided transmission value is not considered.

Because the benefit cost analysis approach utilized in the NYSERDA independent evaluation is limited to only those facilities that would be deployed as a result of the Community Microgrid, it includes the optional addition 5 MW of PV that is anticipated, but excludes the energy produced by the 10 MW of separately contracted PV which will be providing energy to the Community Microgrid, including during periods of islanded operation (see Scenario 2, footnote 13, p.11 of the IEc report). As a result, the independent NYSERDA analysis estimates that the Community Microgrid will produce 17.8 MWh/day—more than sufficient energy to support the local critical facilities, but not sufficient to indefinitely support the estimated 27.3 MWh needed daily to also support 100% of secondary priority community loads even if the 25 MWh battery storage facility was fully charged when the outage occurred. However, we note that the actual quantity of PV available to support the Community Microgrid will be at least 10 MW, making 35.6 MWh/day available to both meet local loads and recharge the storage facility for 24 hour islanded operation. The deployment of the Community Microgrid also increases the PV hosting capacity of the grid to allow an anticipated total of 15 MW of PV, providing 53.4 MWh/day.

Economic Benefits

The benefits analysis performed by the NYSERDA independent evaluator includes the societal benefits related to energy value, savings in energy capacity costs, and avoided emissions damages and costs associated with major power outages. This analysis does not include regional economic and employment impacts associated with the development of the Community Microgrid and associated facilities. This failure to consider the economic and employment impacts when calculating the net societal benefits is applied consistently between proposals and does not invalidate the reported results, but is significant and worth noting. The Clean Coalition Benefit Costs Analysis above does separately consider these factors and reports the results of a NREL Jobs and Economic Development Indicator 20 year analysis for the project in the Regional Economic Impacts section.

Appendix E: Detailed Analysis of Operating Modes

The following section provides a simplified analysis of operation of the key DER components in the three situations: normal, backup mode due to loss of feeder, and backup mode due to loss of transmission. The study is very high level and is intended to illustrate with numbers and graphs how the system would operate, and to identify key variables and settings that will be necessary for a more thorough analysis. It is time-based and uses historical data wherever possible.

Elements of the Model

Figure 1 summarizes all the configuration of the key components used in the analysis. The focus is on the two feeders, 9EU-4N7 and 9EU-4N8, that connect to Bank 4. The point of view when the term "substation" is used below is actually of an implied point of common connection for the two feeders, the 15 MW of PV, the 25 MWh of energy storage located at the substation, the distributed energy storage located at the critical facility sites, the diesel generators located at the substation (currently used primarily for peak reduction), and the backup diesel generators located at the critical facility sites. For analyzing the component as a group, it is assumed they can be isolated from the rest of the substation in the event of a transmission outage but remain connected to each other.

Sign Convention

For the purposes of analysis and plotting, the algebraic sign convention used here is "+" for sources and "-" for loads. Also, from the viewpoint of import/export, export is "+", import is"-".

Import/Export

For normal operation, import will usually mean from the transmission grid to the section under examination. In the case of critical loads islanded during feeder outages, it can imply the local diesel generator would need to be used.

In the charts for the use cases, a variable is plotted called +Exp/-Imp. The context depends upon the use case configuration. It is a net sum of what is going on among the PV, energy storage and loads. If it is positive, the system is sourcing net energy; if negative, the system nets out as a load. For the critical load cases, this normally is with respect to the feeder. For Bank 4 or "substation" cases, the orientation is with respect to the common bus of the substation.

Solar Photovoltaics (PV)

Only PV connected as FIT (Feed in Tariff) is assumed. The assumption for this study is 15 MW DC of PV connected on Bank 4. It is assumed that there would be some "local" PV at or adjacent to the critical load sites along with some "nearby" PV that could be integrated (e.g. via existing or new feeder lines) to assist in operation during backup from a feeder outage. Values for the minimum sizes are given in Table 6.Minimum Solar & Energy Storage Sizing Estimates.

Time data for the solar was obtained from NREL for the Long Island airport. It is normalized to a typical year and listed by day number in the 365 day year. The data was scaled to provide kWh/MW_DC_PV/hr to make it easy to use in one-hour increments. Single and 5-day minimum and maximum sequences for each month were extracted for use in the models.

Day-ahead and day-of forecasts were also used in some cases to determine when and how much to recharge the energy storage. This was also done in concert with the forecast LBMP hourly energy prices.

On the following charts, PV is plotted as a yellow line, going positive as the sun rises (+ = generation).

Energy Storage

As mentioned above, a 5 MW/25 MWh energy storage system is already under consideration for this substation, so that is the driving capacity assumption. For supporting critical load operation during feeder outages, calculations have been done in the section Minimum Solar & Energy Storage Sizing Estimates to estimate minimum energy storage sizes for each critical load. For future analysis, it may be advantageous to include the separate energy storage at the critical loads as part of the total energy storage available for the substation. However, allowance would have to be made for minimum backup load reserves at the critical load sites.

See the Capacities & Thresholds section below for a discussion of energy storage upper and lower capacity limits.

Energy storage is plotted on the charts as positive number when it is sourcing power and negative when it is charging (minus = load).

Loads

1.1.1.7 Load Data

Historical load data was made available for the two feeders, which are both new, for January through mid-September of 2015. Analyses were done to identify strings of consecutive days (1 through 5 days) that had minimum and maximum values for each month.

15-minute AMI data for the pump station critical loads was made available for June-September of 2014. Billing data for the pump sites was available for most of 2013 and 2014 but was not needed for this analysis.

Only billing data was available for the Springs Fire Station. For analysis purposes, it was assumed that the station's load profile matches the feeder it is connected to and was scaled by the monthly billing data.

Loads on the charts are plotted as negative numbers.

1.1.1.8 Load Management

As discussed and shown in the Monitoring, Communications & Control section, load management is a crucial component for operational success in backup mode. It is assumed that critical load customers will have the capability to move their shift their profiles as well as to decrease or increase load when needed.

For some of the critical load cases, the load is shifted by a few hours in backup mode in order to better align the peak of the load curve with the solar generation profile.

Goal

The goal of these analyses is to demonstrate the viability of the Community Microgrid architecture. It will require a sophisticated controller to manage all the key elements in a microgrid in order to orchestrate the interplay of sources, loads and storage to maintain balance. The use cases examine the interplay of the key components source, load and storage.

A common objective to all three modes is to minimize the use of the diesel generators. Since an energy storage asset of 5 MW/ 25 MWh has already under consideration, that item is the cornerstone of the analysis. Managing the State of Charge (SoC) of the battery and recharging it most cost effectively guides the target of this analysis.

The purpose is to identify critical items, options and settings so that the values and ranges needed for detailed analysis can receive focus, and that insight can be gained for this particular configuration. Real historical data was used where possible and reasonable assumptions were made as to capacities and capabilities.

The models attempt to mimic the types of decisions that a microgrid controller would make to manage the system assets under different conditions: normal and backup operations. The controls used were very simple compared to that of a real system but did capture the essence of the decisions to be made and the variables controlling them.

Energy Cost

LBMP data for 2015 was made available for the economic analysis provided in this report. For this analysis, the data was used in some cases to constrain when the energy storage was replenished by forcing the model to use only the lowest 25% percentiles (lowest 6 hours) or lowest 50% (12 hours); the time segments were not constrained to be contiguous.

An attempt was also made to use the upper 25% to guide the discharge time of the energy storage in an arbitrage fashion, but for the dates chosen this was not a good choice. The timing of the top 25% happened to coincide with the afternoon when there was still plenty of sunlight, so the energy storage was depleted before it was needed to support the early evening peak. Both day-ahead and day-of forecasts were used in some cases as considerations for determining magnitude of charging loads.

Separate charts are used to display LBMP data and to indicate the upper and lower percentile regions for each day of the simulation.

Capacities & Thresholds

As mentioned above, substation level capacities for PV and energy storage are part of the design assumptions for this system. Minimum PV and energy storage sizing were calculated for the local PV and energy storage at the critical load sites.

Peak Assist Point

These cases tended to focus on Bank 4 as if it were the entire substation. The decision as to where the energy storage would be needed to cut in (to minimize the use of the diesel generators normally used for peak load assistance) was not given as an input. Attempts at using the model showed that combined loads of around 9 to 10 MVA on Bank 4 provided the thresholds needed to drive the model into exercising the components.

This aspect will need more in depth analysis in future detailed studies.

State of Charge (SoC) Management

SoC was used as major organizing principle and decision-making device in the models. Optimizing the use of the bulk centrally located energy storage as well the local energy storage at the critical load sites was a major goal.

SoC is mathematically an integral; it literally represents everything that has happened to the energy storage system previously, plus an initial condition. The plots for the cases have the SoC as a dashed line and the Min and Max values as dotted lines, displayed using a secondary axis. When SoC is at the lower limit, that is an indication that either import or diesel operation may be needed, depending upon the configuration of the use case.

The critical parameters are:

1.1.1.9 Initial SoC

This was usually set to 50% or to the Maximum SoC level. For local energy storage, reserves will have to be considered for sourcing during backup in the event of an outage; this is the source of the 50% value. This value will need to be examined when more detailed analyses are performed.

1.1.1.10 Minimum SoC

All energy storage systems have minimum SoC values that they recommend users do not cross. Even systems which can be discharged to zero SoC warn about non-linearities below certain levels. This parameter was set to 10% and was not varied.

1.1.1.11 Maximum SoC

All energy storage systems have maximum SoC values that they recommend users do not exceed. This parameter was set to 90% and was not varied.

The major variables addressed have been described above. Others that might want to be considered for future analysis include:

- Round trip efficiencies: This has both static and dynamic components.
- Diesel operation: Indications are given in the use case results where diesel operation may be needed, but it is not included in the calculations.
- Charging energy storage at any time: More analysis could be done on the economics of the energy storage charging and other grid services that energy storage can provide when the need for energy storage is low.
- Breaking the central energy storage into chunks: It should be possible to divide portions of the 25 MWh energy storage among the critical loads. Consideration would have to be given to the backup reserves that would be needed for each critical load. This reserve level could vary based upon seasonal loads and forecasted solar resource.
- Income from other services: These possible uses of the energy storage will require more analyses that tie in the economic return with forecasted values of key variables.
- Voltage regulation, reactive power: Advanced inverters will enable more applications of DER components, but detailed load flow analysis will be required to see if the use of the available power for these cases is needed.

Cases

Case 1: Bank 4 Normal Operations, Worst Case of Min PV, Max Load

Location	Operation	Pk Assist	SoC Initial	LBMP	PV	Load	# Days
Bank 4	Normal	(10,000)	50%	Bot_50%	Min	Max	5
		KVA			15 MW		

This case represents the worst case condition of maximum load for Bank 4 with minimum generation from PV in July. The LBMP pricing signal is constrained to just the bottom quartile (6 hours of lowest prices) in the day for recharging the energy storage. See Figure 18 to follow the description.

On the first day, the SoC rapidly goes from the initial state of max level to minimum level when the energy storage discharges in late afternoon to attempt to clamp the net load at the Peak Assist value of -10,000 kVA. The Peak Assist value is maximum load value on the two feeders that was selected to drive the activity of the model; it does not represent the actual conditions under which the substation uses the diesel generators. The recharge of the energy storage is hindered by several factors:

The constraint on the timing of the LBMP values of the lowest two quartiles

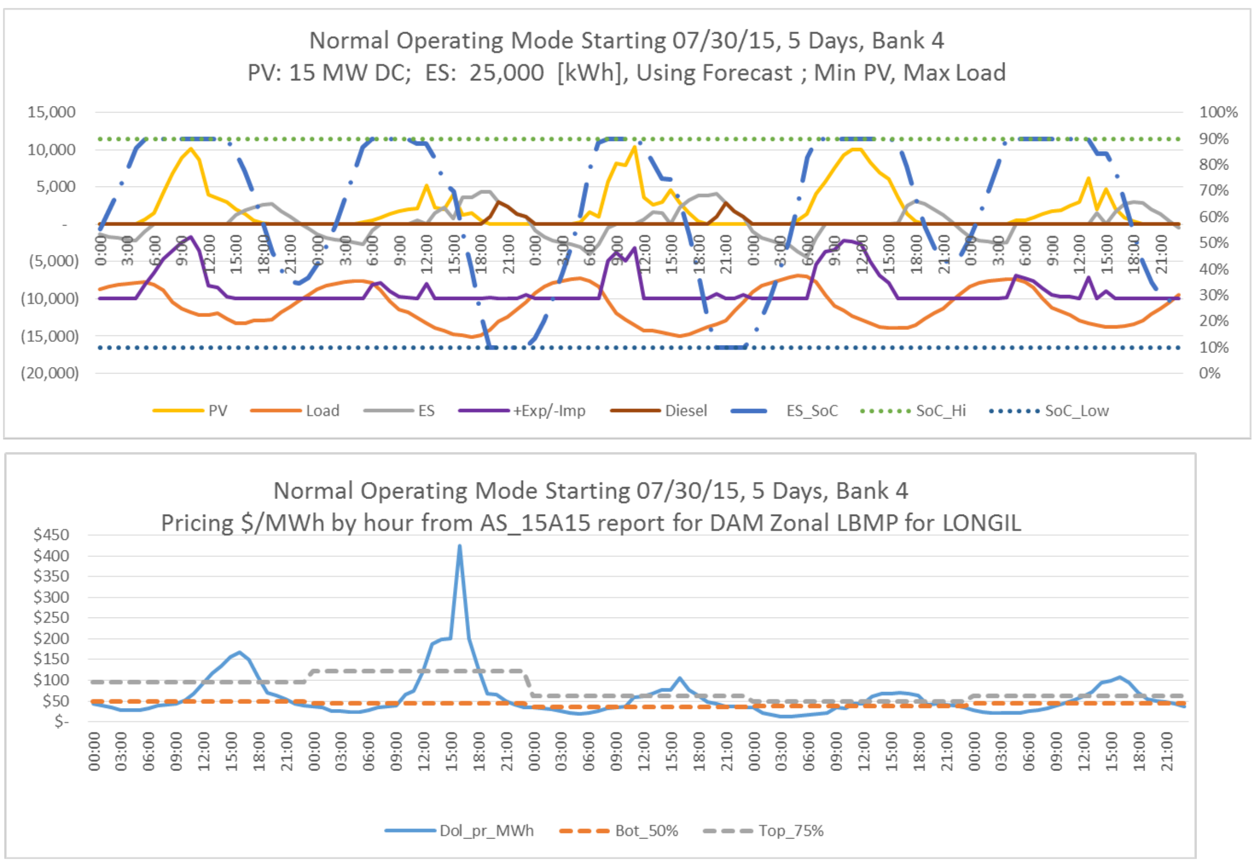
The desire not to exceed the magnitude of the Peak Assist value which is the horizontal portion of the purple +Exp/-Imp line. When the SoC is bottomed out, diesel generation must be added to keep the net load magnitude less than the Peak Assist value.

Low contribution from PV

Constraining the energy storage to recharge during the bottom 50% of prices, it is able to fully recharge (when the constraint was the bottom 25%, it only recovered to 83% on day 2 and 78% on day 3). When the peaks are large and the energy storage has been depleted to minimum SoC, the diesel generators are added to clamp the net load to the Peak Assist Value.

Note that it is only days 2 and 3 with large load and minimal solar that require the diesel generation. Otherwise the solar energy is sufficient to allow the energy storage to handle the evening peak load.

Figure 18: Normal Operation of Bank 4. Worst Case Maximum Load and Minimum PV in July

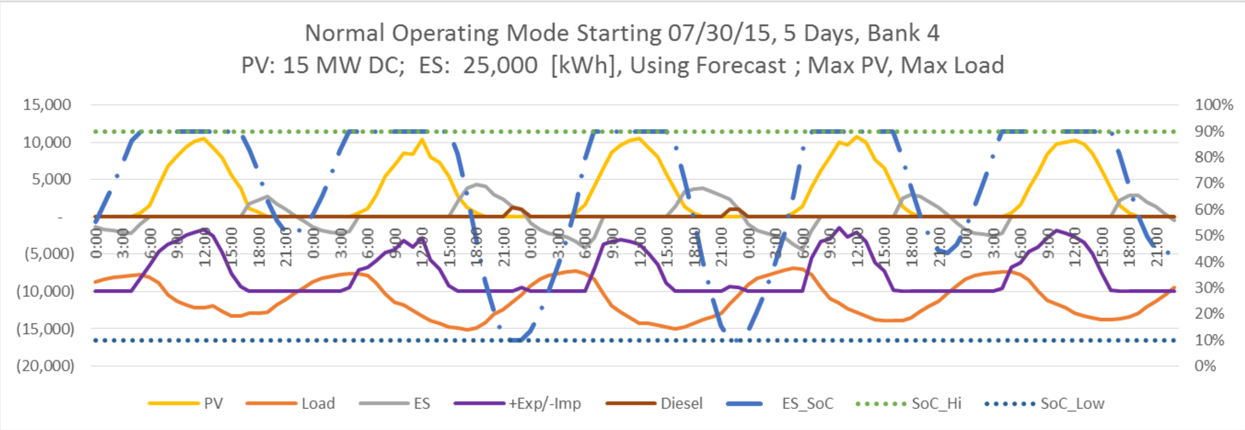


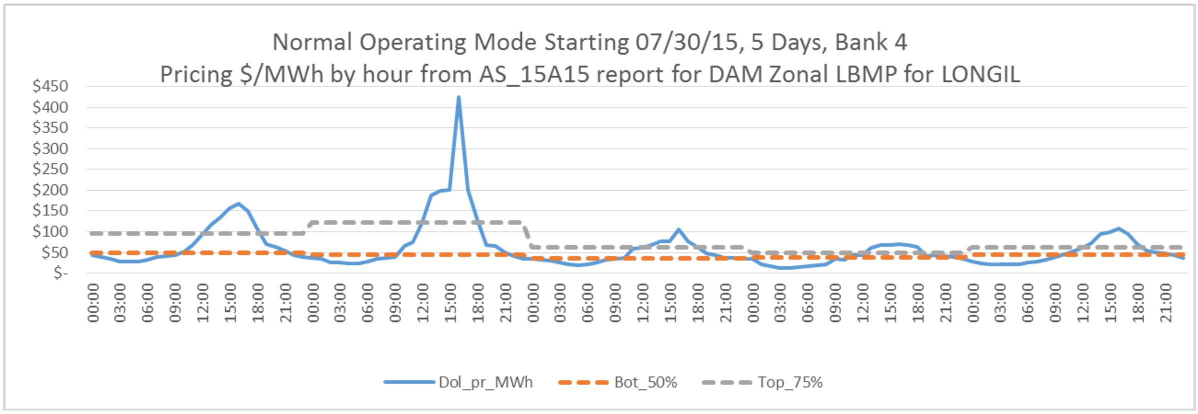
Case 2: Bank 4 Normal Operations, Max PV, Max Load in July

Location	Operation	Pk Assist	SoC Initial	LBMP	PV	Load	# Dayx
Bank 4	Normal	(10,000)	90%	Bot_50%	Max	Max	5
		KVA			15 MW		

This case, shown in Figure 19, illustrates the normal operation of the feeders in Bank 4 with maximum 5-Day PV and under maximum 5-day load in July. The PV contribution can be seen in the reduced amount (both magnitude and time) that the diesel generators are run on days 2 and 3. These changes are consistent with what one would expect in the model and indicate that is usable for making comparisons.

Figure 19: Normal Operation at Bank 4: Max PV, Max Load





Case 3: Bank 4 Normal Operations, Min PV, Min Load in July

Location	Operation	Pk Assist	SoC Initial	LBMP	PV	Load	# Dayx
Bank 4	Normal	(9,000)	50%	Bot_25%	Min	Max	5
		KVA			15 MW		

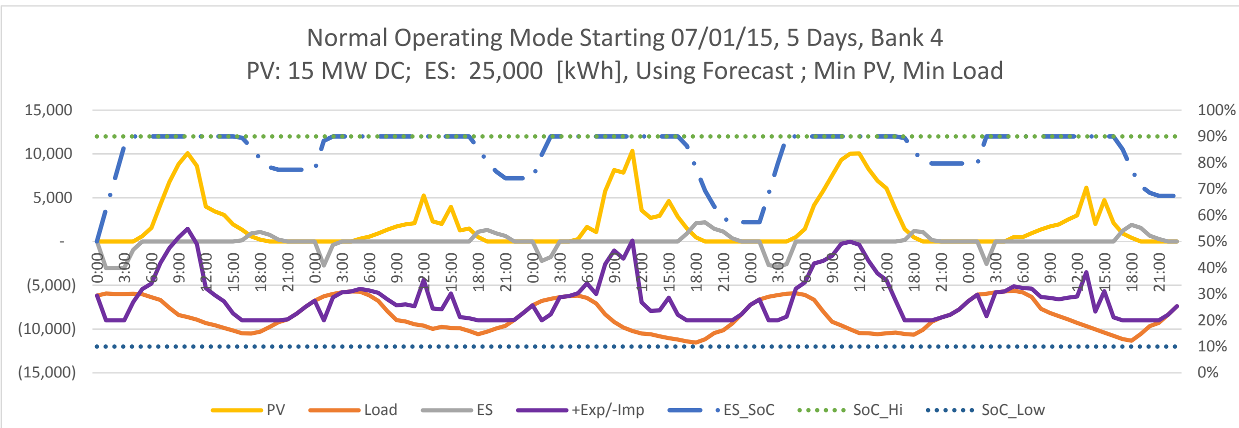
This case covers the situation of good solar resource and minimum load. It is the opposite of the first extreme case. The results are shown in Figure 20.

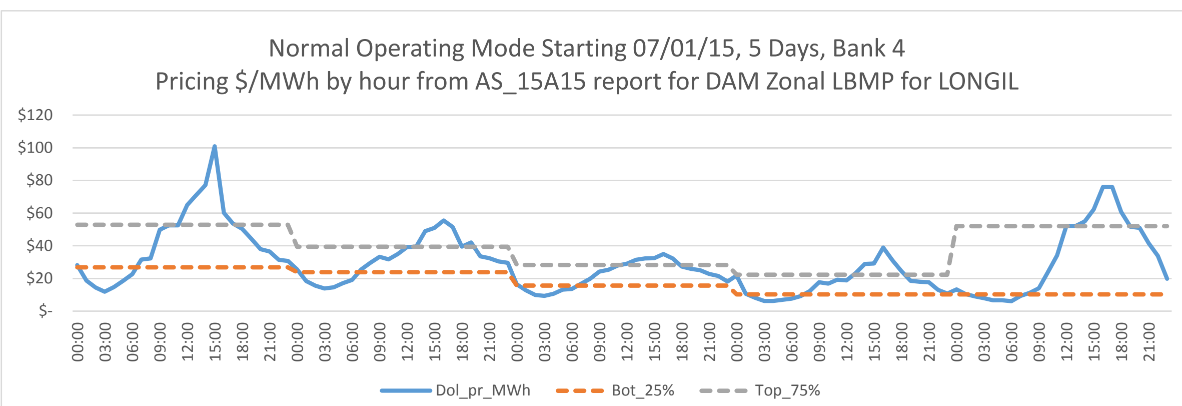
Note the parameters of the model have been reduced to values less extreme than in the prior two cases where limits were being reached. Here the Peak Assist point has been reduced back to -9000 kVA (in order to drive the model to show something interesting), initial SoC is reduced from the upper limit back to 50%, and the LBMP pricing window is back to the bottom quartile.

The impact of minimum load is dramatic. The SoC quickly charges up to maximum and is able to recharge fully during the best price (lowest quartile) windows of the LBMP. The energy storage sourcing is able to control the evening peak loads and clamp the +Exp/-Imp line so that it never drops below the Peak Assist setting. The SoC never bottoms out while doing this.

When the forecast indicates days like this are coming, the extra margin in the energy storage could be considered for use in other services such as arbitrage.

Figure 20: Normal Operations for Bank 4, Maximum PV and Minimum Load





Case 4: Bridgehampton Pump Station, Sustained Islanded Operation in July

Location	Operation	Pk Assist	SoC Initial	LBMP	PV	Load	# Dayx
BH Pump	Backup	-	50%	n/a	Min	Typical	5
		KVA			1 MW		

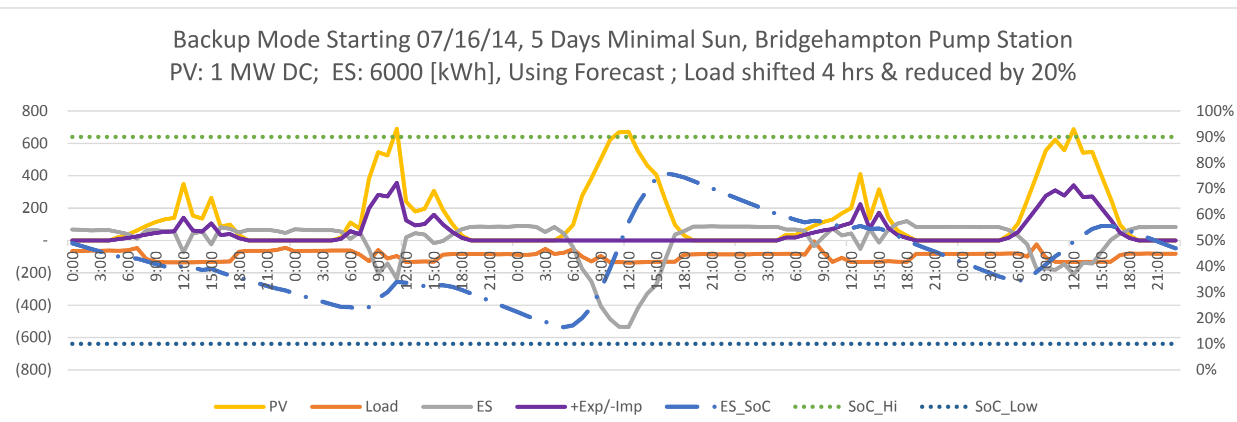
This case examines the operation of the Bridgehampton pumping station when a feeder outage initiates operation in the islanded mode. Refer to Figure 21 for a plot of the operation, and to Figure 3 for the configuration.

In this configuration, each critical load has disconnected from the grid and is running on its local energy storage plus whatever solar is onsite or can be reasonably switched over to support the ongoing operation. It is assumed for this case that half the energy storage capacity is kept in reserve for backup operation, and that establishes the initial SoC. For calculations to size the minimum PV and energy storage to support the critical loads, see Table 6 and Table 7.Minimum Solar & Energy Storage Sizing Estimates.

Note that the energy storage immediately starts discharging to support the load. In this case, the water utility is directed to initiate load shifting by 4 hours to align the maximum load with the solar peak, and conservation to reduce its overall demand. Note in the chart that the peak loads (orange line) align with the solar peaks. Normally the water utility schedules its peak loads during the off-peak periods. See Figure 2 for an example of what the shifted and reduced curves look like.

The first 2 days have minimal solar and the SoC continues on a downward trend as it provides power to the pumps along with the sun. On day 3 there is sufficient PV power to recharge the energy storage and bring to SoC to over 50%. Since this solar resource is the worst case 5-day minimum for July, sustainable operation for the pumping station can be achieved from PV with the use of properly sized energy storage.

Figure 21: Backup from Feeder Outage, Bridgehampton Pump, Minimum PV



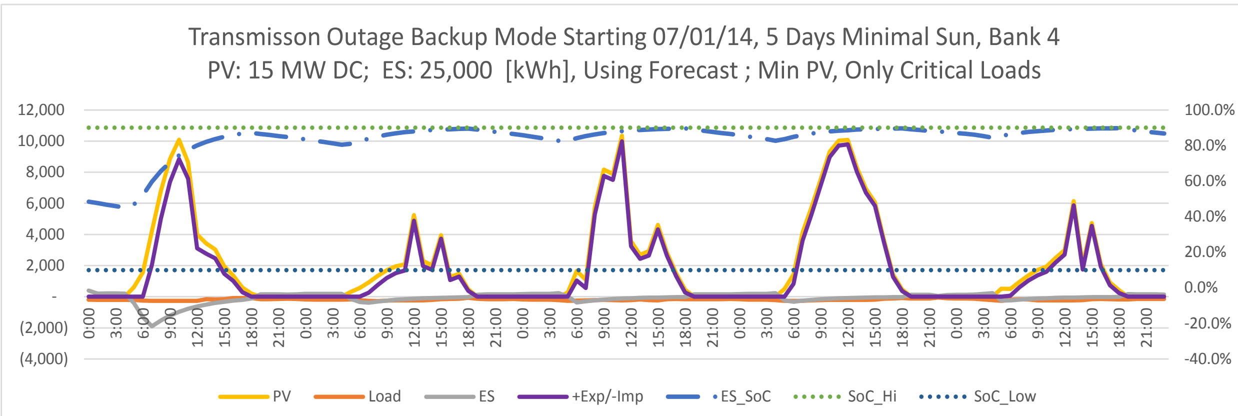
Case 5: Loss of Transmission

Location	Operation	Pk Assist	SoC Initial	LBMP	PV	Load	# Days
Bank 4	Backup	n/a	50%	Bot_25%	Min	Max	5
	Bank 4				15 MW	Critical Lds	

This case covers the operation of the Bank 4 feeders and critical loads when there is a transmission outage. For the circuit configuration, see Figure 4: Operation of Microgrid Assets in Backup Mode, Tier 1 & 2 Loads Only. For the summary plot, see Figure 22 below.

Only a glance at the plot shows that there is much more energy available to power the three critical loads during this worst case minimum solar interval. With 15 MW of PV and 25 MWh of energy storage, the SoC loses very little value between solar recharges. During this simulation, the total PV generated was 240 MWh and the total load was 23 MWh. With 10x more energy than is needed, there is more than enough power to supply a large amount of Tier 2 loads. No attempt was made in the simulation to add load shift or load reduction because the order of magnitude difference between source and load. If sufficient Tier 2 loads cannot be found, then the PV will need to be curtailed or some of the PV will need to be disconnected.

Figure 22: Bank 4 Operation during Transmission Outage, Tier 1 Loads Only



Appendix F: Existing Diesel Generator Usage Profile

Diesel Generator Weekday Operation:

Figure 23, Figure 24, and Table 13 show the weekday usage profile of the existing 6 MW of diesel generators located at the East Hampton GT substation (three 2 MW diesel generators). Figure 25, Figure 26, and Table 14 provide comparable information for the weekend usage. The combined energy storage in the LICMP configuration will be used to replace the use of this asset in normal operations.

Diesel Generator Weekday Operation:

Figure 23: Diesel Generator Weekday Hourly Average Power

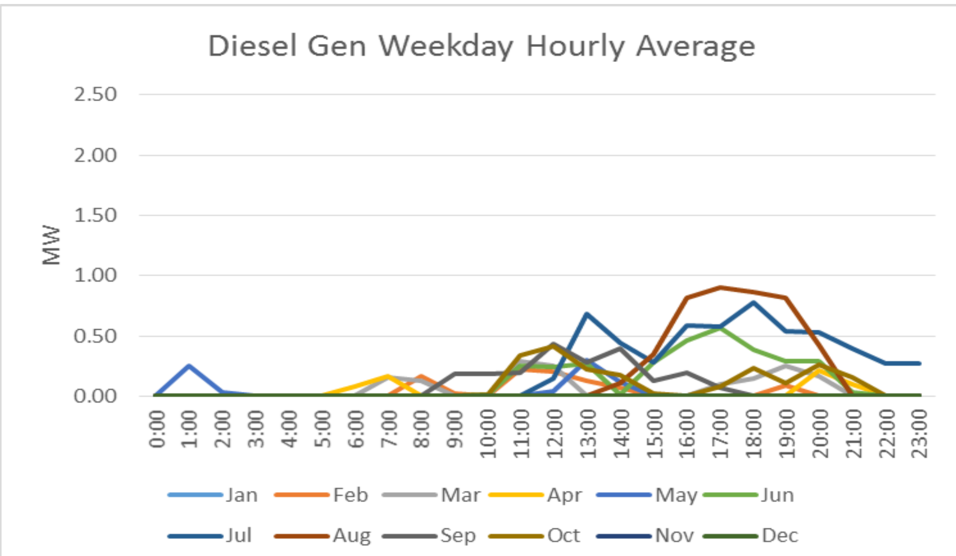


Figure 24: Diesel Generator Weekday Daily Average Energy by Month

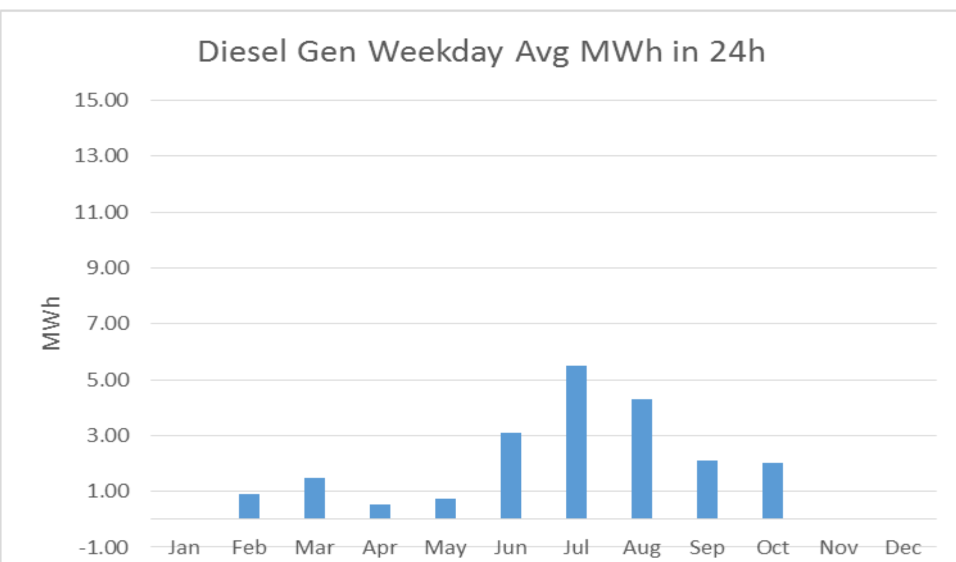


Table 13: Diesel Generator Weekday Operational Power Statistics by Month

Diesel Gen Weekday Hourly Average							
	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MWh]
Month	Min	Min_gt0	NoonMin	Avg	Max	StdDev	24hr_Avg
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.08	1.47	0.04	3.16	0.29	0.91
3	0.00	0.14	5.21	0.06	6.04	0.48	1.49
4	0.00	1.69	0.00	0.02	4.64	0.28	0.55
5	0.00	0.64	0.92	0.03	5.26	0.35	0.74
6	0.00	0.02	5.13	0.13	6.03	0.83	3.11
7	0.00	0.01	0.86	0.23	6.00	1.08	5.50
8	0.00	0.03	0.00	0.18	6.01	0.95	4.29
9	0.00	0.01	0.04	0.09	5.18	0.48	2.09
10	0.00	0.00	0.00	0.09	6.01	0.62	2.04
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Diesel Generator Weekend Operation:

Figure 25: Diesel Generator Weekend Hourly Average Power

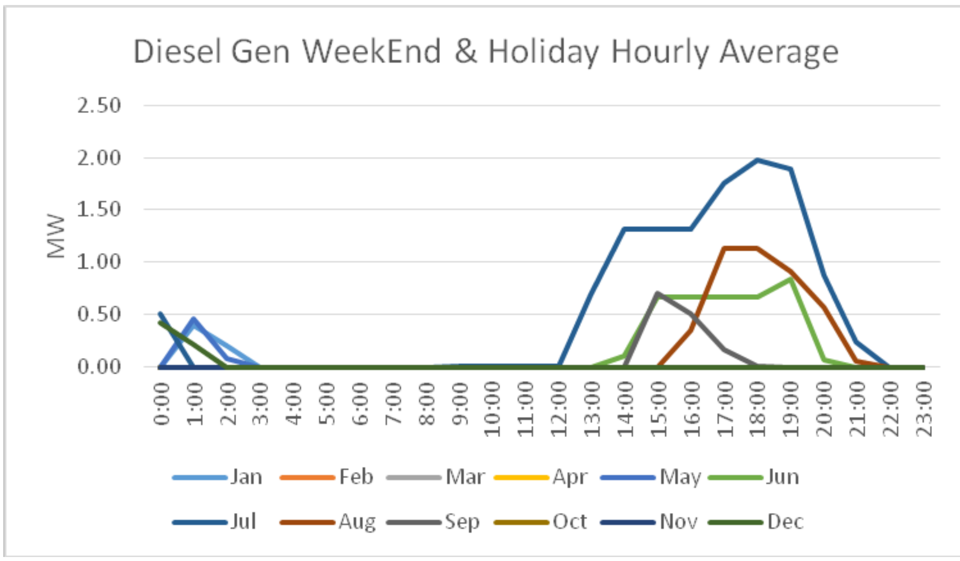


Figure 26: Diesel Generator Weekend Daily Average Energy by Month

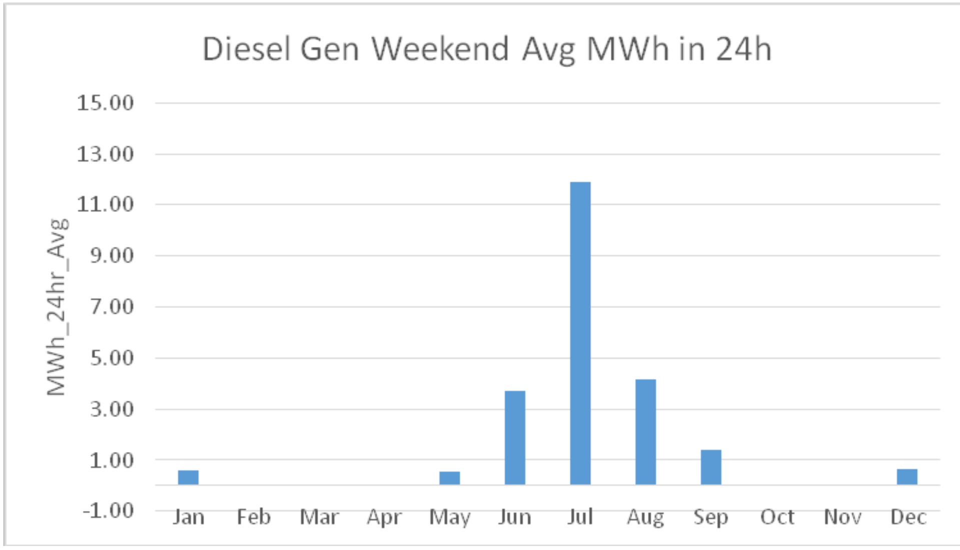


Table 14: Diesel Generator Weekend Operational Power Statistics by Month

Diesel Gen WeekEnd & Holiday Hourly Average							
	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MWh]
Month	Min	Min_gt0	NoonMin	Avg	Max	StdDev	24hr_Avg
1	0.00	2.00	0.00	0.03	4.00	0.29	0.60
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.74	0.00	0.02	4.55	0.30	0.53
6	0.00	0.65	0.00	0.15	6.01	0.89	3.69
7	0.00	0.00	0.01	0.50	6.04	1.58	11.91
8	0.00	0.58	0.00	0.17	5.70	0.93	4.16
9	0.00	0.01	0.00	0.06	4.53	0.44	1.38
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	2.19	0.00	0.03	4.18	0.30	0.64

Appendix G: Energy Storage Sizing Calculations for Critical Loads

Table 15 displays calculations for sizing energy storage at each critical load site assuming average 20% load reduction during backup mode. December and July are chosen because they represent the min/max loads as well as min/max solar resource months, respectively. These tables are summarized in the section Minimum energy storage & Solar Estimates.

The calculations are intended to size the energy storage needed to set up ongoing PV renewal of the energy storage for each critical load, based upon vary assumptions as to the availability of the PV resource. PV resource data is based upon hourly NREL values for Long Island.

Three State of Charge (SoC) assumptions are shown as initial conditions for the outage: 50%, 75%, 25%. Minimum SoC target was assumed to be 10%.

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Table 15: Energy Storage Sizing Calculations for Critical Loads

Critical Load:		**Pump Stn: Bridgehampton**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Pump Stn: Oak_View**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Springs Fire Station**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Totals**	
Max Load [kW]		200					115					35						[kW]
Max Avg Daily Energy [kWh/24hr]		2,842					1,423					273						[kWh/24 h
December Case																		
Avg Daily Load [kWh/24 hr]		1,416					561					226					2,203	[kWh/24 h
ES [kWh]			4,424	3,717	3,562			1,754	1,400	1,323			706	638	623			[kWh]
PV needed to replenish avg 24 hr load in Dec [MW DC]		1.284					0.643					0.123					2.050	[MW DC]
PV output, December [kWH/24 hr/MW_DC]	2,213.5																	
July Case																		
Avg Daily Load [kWh/24 hr]		2,842					1,423					273					4,538	[kWh/24 h
ES [kWh]			8,882	8,522	7,445			4,445	4,265	3,726			853	819	715			[kWh]
PV needed to replenish avg 24 hr load in Jul [MW_DC]		0.654					0.327					0.063					1.044	[MW DC]
PV output, July [kWH/24 hr/MW_DC]	4,345.9																	
ES Capacity Available at start of event																		
State of Charge @ start of e	50%																	
SoC min level allowed	10%																	
Energy initally available	40%																	
ES Efficiency Loss, round tri	20%																	
PV available to recharge ES																		
PV available:	**See minimum requirements calculated for each critical load site**																	
Cloudy day output, December:			Dec min/avg:	17.6%														
Cloudy day output, July:			Jul min/avg:	39.3%														
				Dec P10/avg:	21.5%													
				Jul P10/avg:	70.3%													

Critical Load:		**Pump Stn: Bridgehampton**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Pump Stn: Oak_View**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Springs Fire Station**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Totals**	
Max Load [kW]		200					115					35						
Max Avg Daily Energy [kWh/24hr]		2,842					1,423					273						
December Case																		
Avg Daily Load [kWh/24 hr]		1,416					561					226					2,203	[kWh/24 h
ES [kWh]			2,723	2,287	2,192			1,079	862	814			434	392	383			[kWh]
PV needed to replenish avg 24 hr load in Dec [MW DC]		1.284					0.643					0.123					2.050	[MW DC]
PV output, December [kWH/24 hr/MW_DC]	2,213.5																	
July Case																		
Avg Daily Load [kWh/24 hr]		2,842					1,423					273					4,538	[kWh/24 h
ES [kWh]			5,466	5,244	4,582			2,736	2,625	2,293			525	504	440			[kWh]
PV needed to replenish avg 24 hr load in Jul [MW_DC]		0.654					0.327					0.063					1.044	[MW DC]
PV output, July [kWH/24 hr/MW_DC]	4,345.9																	
ES Capacity Available at start of event																		
State of Charge @ start of e	75%																	
SoC min level allowed	10%																	
Energy initally available	65%																	
ES Efficiency Loss, round tri	20%																	

Critical Load:		**Pump Stn: Bridgehampton**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Pump Stn: Oak_View**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Springs Fire Station**	Min Local ES for avg load with no PV charging [kWh]	Min Local ES for avg load with min PV charging [kWh]	Min Local ES for avg load with P10 PV charging [kWh]		**Totals**	
Max Load [kW]		200					115					35						
Max Avg Daily Energy [kWh/24hr]		2,842					1,423					273						
December Case																		
Avg Daily Load [kWh/24 hr]		1,416					561					226					2,203	[kWh/24 h
ES [kWh]			11,798	9,912	9,500			4,677	3,734	3,527			1,882	1,701	1,661			[kWh]
PV needed to replenish avg 24 hr load in Dec [MW DC]		1.284					0.643					0.123					2.050	[MW DC]
PV output, December [kWH/24 hr/MW_DC]	2,213.5																	
July Case																		
Avg Daily Load [kWh/24 hr]		2,842					1,423					273					4,538	[kWh/24 h
ES [kWh]			23,685	22,724	19,855			11,854	11,373	9,937			2,276	2,184	1,908			[kWh]
PV needed to replenish avg 24 hr load in Jul [MW_DC]		0.654					0.327					0.063					1.044	[MW DC]
PV output, July [kWH/24 hr/MW_DC]	4,345.9																	
ES Capacity Available at start of event																		
State of Charge @ start of e	25%																	
SoC min level allowed	10%																	
Energy initally available	15%																	
ES Efficiency Loss, round tri	20%																	

Appendix H: Links to CC RFI and to PSEG LI RFP Documents

The following documents were too long to include as appendices, so links to them are provided.

Clean Coalition RFI for Microgrid Controller

http://www.clean-coalition.org/site/wp-content/uploads/2016/05/Clean-Coalition-LICMP-RFI-18_gt-16-July-2015.pdf

PSEG RFP for South Fork Energy Storage

https://www.psegliny.com/page.cfm/AboutUs/Proposals/SouthFork

Appendix I: Smart Inverter Working Group

The Smart Inverter Working Group (SIWG) is sponsored by the California Energy Commission to revise Rule 21 that controls interconnection of equipment to the power grid. The Clean Coalition has been a contributing member of the SIWG since its formation. This approach will likely be adopted widely as the basis for how the industry deploys higher levels of DER. This architecture leaves primary grid operations in the hands of the utility, communicating with and controlling DER assets as needed, whether individually or as aggregated by a partner. In a Community Microgrid configuration especially, this approach enables the utility to optimize and balance load and generation across the substation area as needed, and including during islanded mode.

Below are two SIWG summary diagrams demonstrating this architecture. The SIWG has found that these diagrams capture the key elements that must be addressed in controlling distribution assets, acknowledging the diversity of options to choose from while allowing focus on a single aspect to evaluate pros and cons with respect to other options. Both utility-side and behind-the-meter connected equipment are included.

By adopting this approach, a utility can leverage the work already undertaken by the SIWG, utilizing an architecture that will likely be deployed widely. Thus, the LICMP can deliver an extensible model - to incorporate additional local resources as needed, with little friction, and also to provide a solution that can be replicated easily in other service areas.

The SIWG has released specifications for advanced inverter operational characteristics in Phase 1 and is now working on the monitoring, control and communications (MC^2) aspects in Phase 2. The MC^2 are needed by utilities to deploy and utilize the features and capabilities of inverters and other DER in a variety of potential configurations. These diagrams present a good vehicle for discussing the broad range of MC^2 choices and identifying the key elements that must be addressed.

More notes on the two diagrams are provided below:

In Figure 27, the potential types of control configurations are defined. Level1 (green box) are the assets interconnected to the power grid. Level 2 (blue box) are potential control structures that might be used to consolidate MC2 paths. Level 3 (pink) represent the communications paths (ICT) that would carry information and signals. Level 4 (gold) represents the grid operations control for the utility. Level 5 (purple) represents aggregators that can simplify the number of elements the utility has to manage in its fleet of resources. Note that the utility itself can also act as the aggregator.

Various communication paths are represented by the lightning lines with numbers. The circled numbers also correlate to communications structures on the second diagram. The five control paths for the Distribution System Operator are:

- Utilities directly to DER components
- Utilities to Facility Energy Management Systems (EMS)
- Utilities to Aggregators
- Aggregators to EMS
- Aggregators to DER components

Figure 28, provides more details about options for implementing the control paths shown in the first diagram. The numbers represent communications paths, both internal and external, for the equipment and do include the DSO control paths of the first diagram. The line colors represent types of protocols listed in the legend. The cloud represents the types of physical communications methods that the utility would specify, control or own.

Figure 27: SIWG DER Control Diagram 1: Scope of SIWG Phase 2

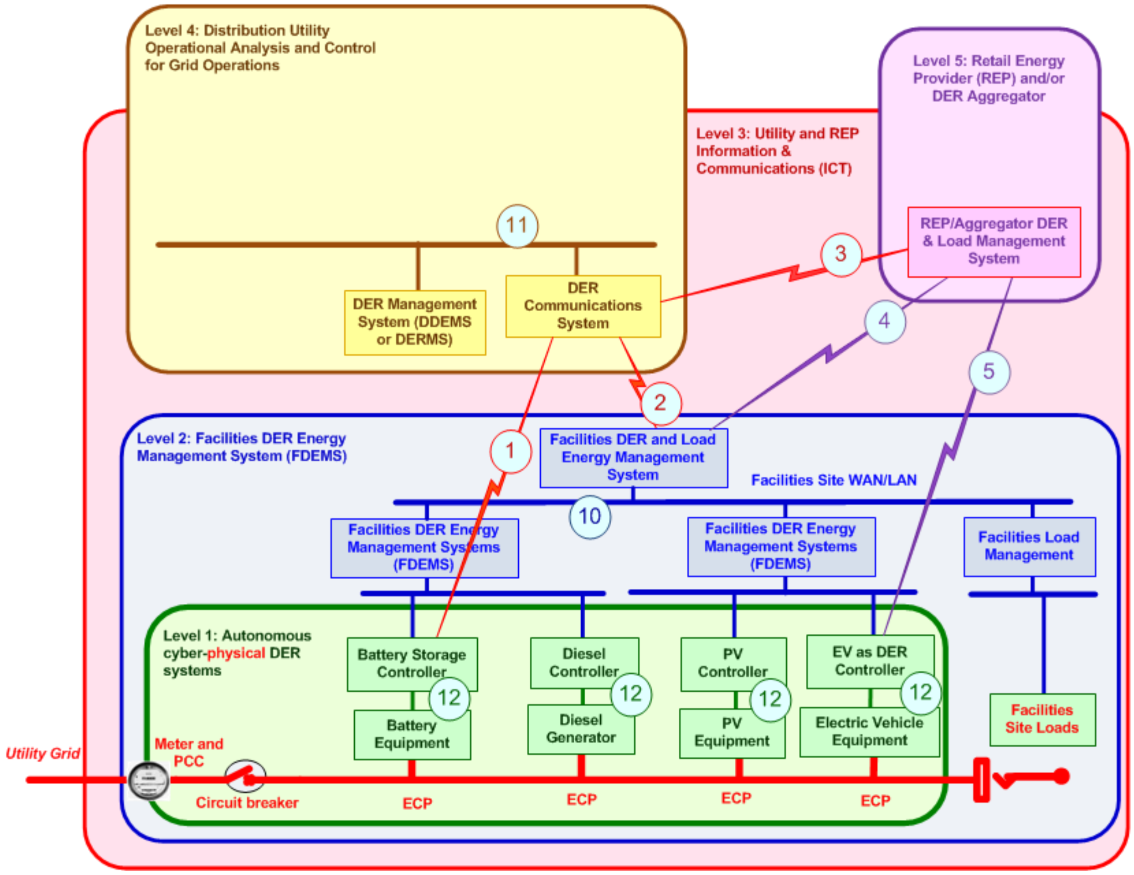
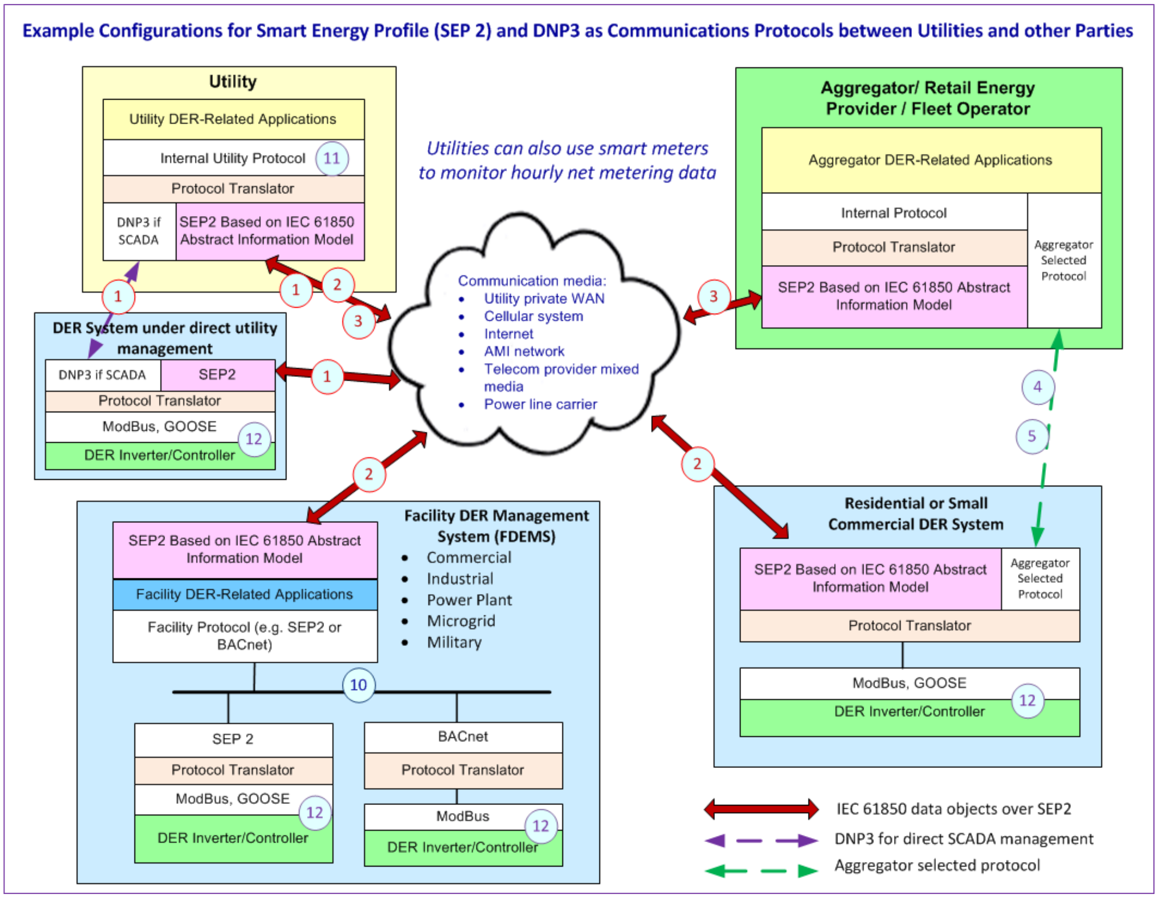


Figure 28: SIWG DER Control Diagram 1: Scope of SIWG Phase 2



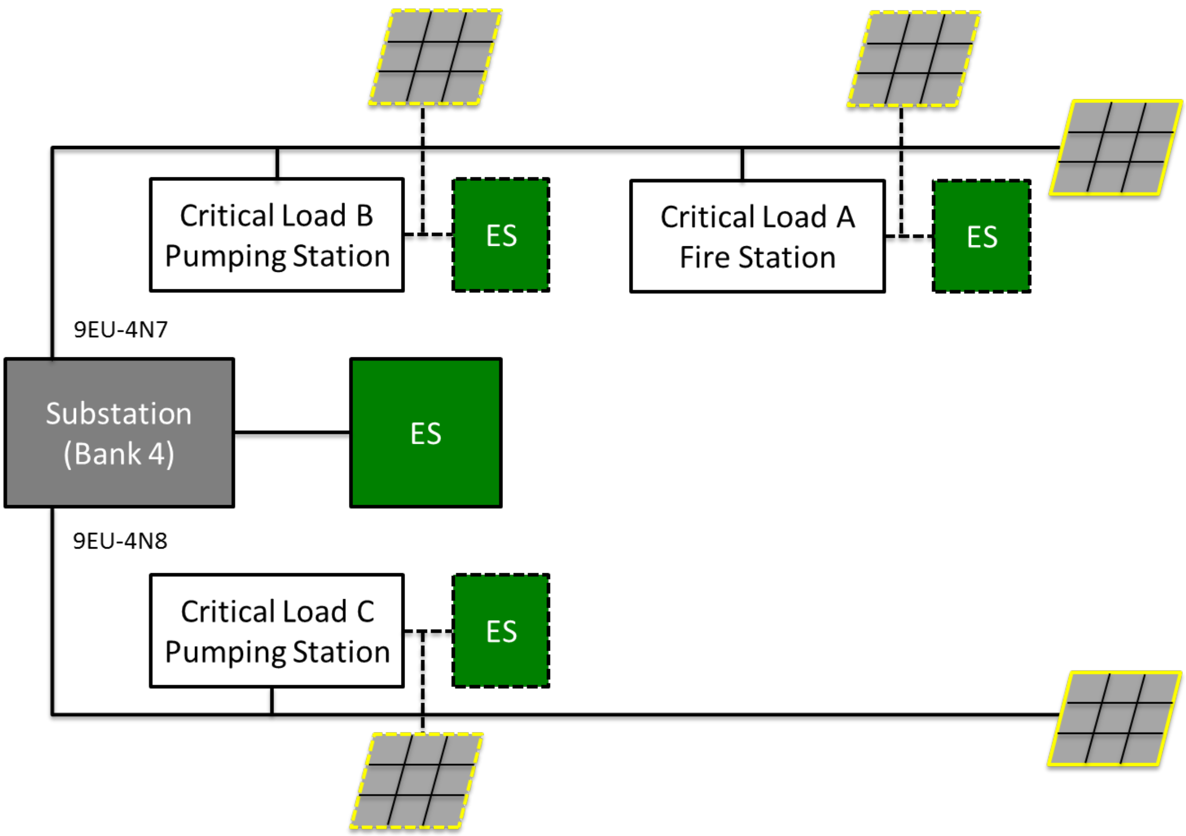
Appendix J: All Project Configurations Considered

The LICMP requires a configuration that satisfies the Functional Requirements. Three configurations are provided below as options. The option shown in the Configuration Option 2: Distributed "B" was the basis for the configuration in the Solution Profile and Figure 1; possible dedicated lines were added for operation utilizing nearby PV during a feeder outage.

Configuration Option 1: Distributed "A" (Figure 29)

- Energy Storage: large energy storage facility connected to substation via dedicated feeder, plus distributed energy storage facilities located at critical load sites behind the meter.
- PV: at critical load sites and/or other sites, connected via normal feeders
- Critical Loads: in backup mode, served locally by distributed solar + energy storage. Relevant solar facilities will be shunted to power critical loads and distributed energy storage facilities directly.

Figure 29: Configuration Option 1: Distributed "A"

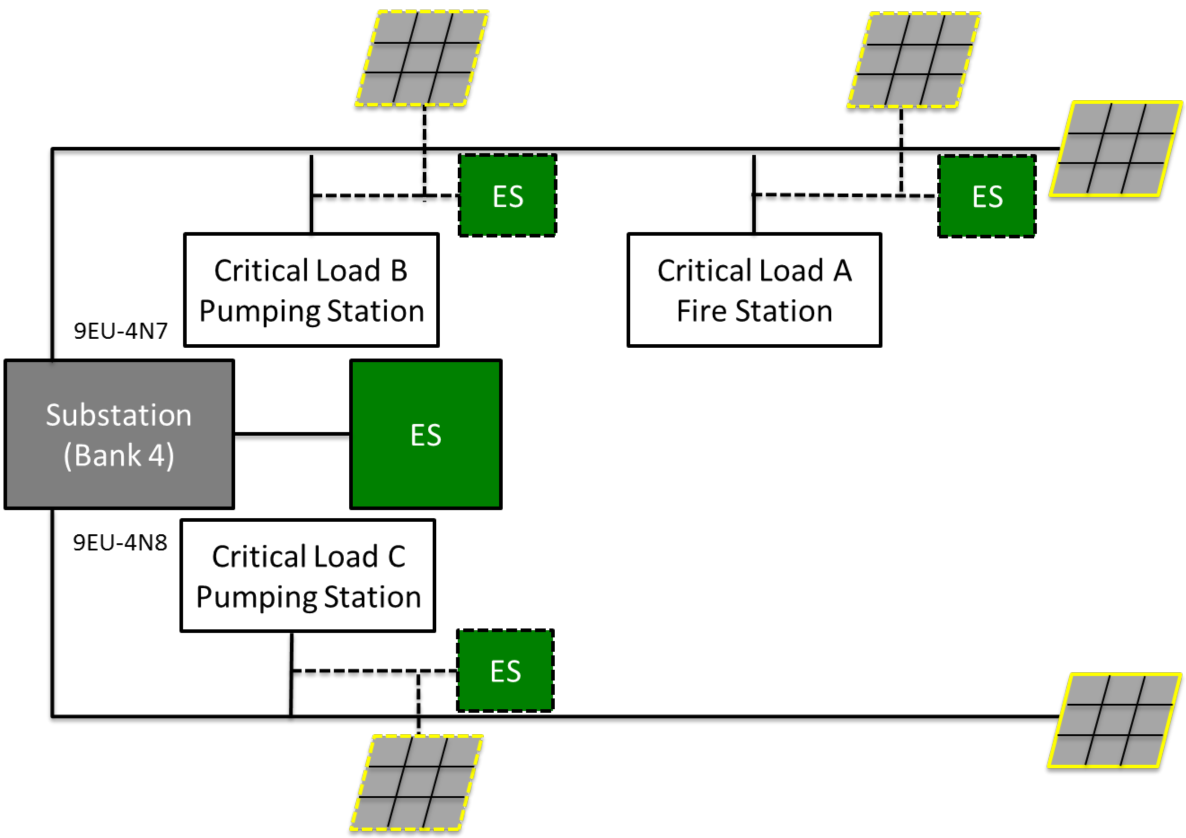


Configuration Option 2: Distributed "B" (Figure 30)

Note: this configuration is the one proposed for the LICMP and is shown in more detail in the Configuration section of the main document.

- Energy Storage: large energy storage facility connected to substation via dedicated feeder, plus distributed energy storage facilities located at or near critical load sites and controlled by the utility, e.g. in front of the meter.
- PV: at critical load sites and/or other sites, connected via normal feeders
- Critical Loads: in backup mode, served locally by distributed solar + energy storage. Relevant solar facilities will be shunted to power critical loads and distributed energy storage facilities directly.

Figure 30: Configuration Option 2: Distributed "B"



Configuration Option 3: Consolidated (Figure 31)

- Energy Storage: single large energy storage facility connected to substation via dedicated feeder
- PV: at critical load sites and/or other sites, connected via normal feeders

- Critical Loads: in backup mode, Bank 4 and its feeders island from the transmission grid and shed all non-critical loads. Shedding will be performed via utility-controlled DR, by switching off non-critical load customers.

Figure 31: Configuration Option 3: Consolidated