# Distributed Energy Resources for Water Resource Recovery Facilities: A Metropolitan City Case Study


**Abstract**

This paper discusses the application of distributed energy resources (DERs) at water resource recovery facilities (WRRF). The DERs considered include solar photovoltaic (PV) systems, biomass electricity generation, and energy storage systems (ESS). The financial and demand management implications of the deployment of various DER combinations are analyzed. The load profile of a single plant is studied in order to draw conclusions regarding the optimal size for energy storage solutions based on the goals of the WRRF. A case study of a Medium sized WRRF, located in a large metropolitan area, is used to compare different financial and technical implementation strategies. An ideal combination of DERs is determined based on analysis of various scenarios for nine distinct use cases. The overarching goal of this paper is to understand the potential of various combinations of DERs for managing peak demand and resilience at WRRFs. Elements in the financial models are compared to determine the combination that creates a financially viable project while providing tangible benefits in resilience and/or demand management to the WRRF.



*Keywords:* distributed energy resources, energy efficiency, financial models, energy storage, renewable energy, resilience, sustainability, water resource recovery facilities.

## Contents

## 1. Introduction

The U.S. government has committed to a 50%[1] reduction in net green house gas emissions economy-wide by 2030 [1]. WRRFs have the highest energy consumption density when compared to the rest of the city owned facilities [2].

Energy is used for various functions in wastewater treatment – pumping, aeration, odor control, heating, de-watering - in varying proportions based on the type of treatment process. In general, energy is used to breakdown and neutralize pollutants in the wastewater stream to comply with pollution control parameters established in operating permits following regulatory discharge standards.

Many metropolitan cities have set aggressive greenhouse gas (GHG) emission reduction targets via renewable energy and energy storage systems (ESS) commitments and energy efficiency measures. For example, NYC has pledged to install 100 MW of solar PV by 2025 and 500 MW of energy storage by 2025. NYS has set a target of 6,000 MW of solar PV by 2025 and 3,000 MW of energy storage by 2030 [2]. Energy efficiency measures targeting key processes are also an effective strategy to reduce energy usage. In the largest 20% of plants which process roughly 75% of the nation's wastewater [3], secondary treatment is used and aeration for this process typically becomes the largest plant energy use, 50-60% of total energy. Pumping is typically the next largest use, 10 – 20% of plant use [4]. energy use reduction of 10 - 20% is conservatively estimated as possible from comprehensive energy efficiency project work across multiple plant functions, primarily impacting electricity use and yielding substantial GHG emission reduction. Energy efficiency improvement in these processes are the subject of active study [4], and are the subject of a separate paper.

This paper addresses DER opportunities available to WRRFs. Since water and wastewater treatment is one of the largest areas of municipal energy use, we suggest that implementing distributed energy resources (DERs) at wastew-

[1] from fiscal year 2005 as a baseline

ater treatment plants is an important part of achieving city and state carbon reduction goals.

Water resource recovery facilities ensure the health of waterways and bathing beaches, as well as provide a consistent water and wastewater service— playing a critical role in public health and the city's economic vibrancy. The water and wastewater systems are two parts of a city's water infrastructure: 1) the supply/distribution system and 2) the collection/treatment of used water with solid waste and storm run-off water [5]. Mitigating the environmental and economic impacts of WRRFs will ensure that the water cycle of cities aligns with recognized resilience metrics. Utilizing the available DERs at WRRFs, we will demonstrate how this resilience capability can also provide cost and energy savings through load management and incentive revenues.

The paper focuses on an example case of a medium sized WRRF with a design capacity of 60 million gallons a day (MGD) located in a major metropolitan city. The case study will determine the most appropriate technical design for the implementation of individual and combinations of three available DERs: solar, energy storage systems (ESS) and biogas generation. The financial implications of each technical scenario will be compared and discussed.

This paper attempts to understand what the financial and technical implications are if biogas generation, solar and an ESS system are implemented on site to offset the demand and increase the resilience at the WRRF.

## 2. Material and Methods

WRRFs have large consistent loads which are critical to the infrastructure of the communities they support. The objective of this paper is to show, using an urban case study, how renewable resources may be applied to manage the electric load of these facilities. The paper examines both technical and financial options.

After an overview of distributed energy resources (DER) applications for WRRF, we consider the opportunity for load management within constraints typical of WRRF. Load management is considered for both demand/cost reduction and for resilience goals. Design and system sizing are developed for the WRRF site under five DER scenarios, taking into account project economics based on capital costs and project revenues, which include avoided energy costs and available incentive/contract payments.

The five DER scenarios are 1) solar plus storage (ESS), 2) standalone biogas generation, 3) biogas with solar 4) biogas with solar plus storage, and 5) resilience. Two project finance methods, debt/equity and power purchase agreement (PPA) are applied to each of the combinations, except Resilience, resulting in nine scenarios analyzed. For the Resilience scenario, the difference in size between the generation capacity of the DER and the size of the ESS required make the PPA non-viable, so it is evaluated only under a host-owned debt/equity structure.

The size of the PV resource is established based on available surface areas and exposures, using the Helioscope tool,a web-based software package created by Folsom Labs[2]. The PV resource is quite small in relation to the facility's electrical load, so PV is maximized without optimal sizing analysis. For ESS an optimal sizing and dispatch strategy was developed using the System Advisory Model (SAM) from the National Renewable Energy Lab (NREL). SAM models performance and financial scenarios based on system specifications provided. Based on the system model chosen and technical and financial parameters entered, SAM provides a cash flow statement and performance output data. In addition, a single model can be run multiple times changing only a few chosen parameters on each run. This Parametric functionality enables a comparison of the performance and financial outputs of each of the different parameters for a specific scenario modeled to determine the optimal system specifications. This functionality was used to determine the appropriate ESS size for the demand reduction scenarios. SAM uses data from specified equipment including modules, inverters, batteries, and engine specifications along with hourly load profile

[2] https://www.helioscope.com/

and weather data. Additional inputs include costs, both capital and O&M, and financial inputs such as IRR targets, debt coverage ratios and financing costs in order to calculate system outputs. Outputs generated by SAM include cash flow data, net present value (NPV), PPA price needed to achieve IRR targets, and system performance on an hourly, daily, monthly and yearly basis.

## 3. DERs in WRRFs

There are various distributed energy resources opportunities available to water resource recovery facilities. WRRFs extensive physical footprint, production of biogas as a byproduct and proximity to water provide ideal conditions for various DERs. These resources include solar PV, biogas for combined heat and power, food waste co-digestion, offshore wind, and tidal or outfall microturbines. The energy generating opportunities are all enhanced by the addition of large scale ESS.

It is possible for a comprehensive set of DERs, especially with the addition of fuel stocks such as food waste for co-digestion, to fully offset the plant's electric load and perhaps even become an energy exporter, providing additional energy for a community microgrid [6]. This potential has been demonstrated in advanced plants but is beyond the scope of the present paper. For this paper we limit our consideration to combinations of solar PV, biogas generation, and ESS, which have relatively straightforward implementation pathways, given sufficient funding, at most WRRFs.

### *3.1. Solar Photovoltaics (PV)*

The land area covered by a WRRF provides an opportunity for various system layouts of solar PV. The potential areas for PV installation include roofs of the facility's buildings, canopy solar over parking lots and walkways, and ground mounted solar on open land. Roof top, ground mounted and land-based canopy solar are standard installation options with known challenges and costs[3].

Solar is being used more and more to offset the energy needs of WRRFs. However, space can be a constraint, and solar can rarely cover the entire energy needs of a WRRF. In California, Strazzabosco et al. (2019) observed that plants larger than 50 MGD rarely had solar installed, and plants smaller than 5 MGD usually had solar as their only renewable source. When installed, solar provided between 8% - 30% of the facility's electricity needs [7].

Much of the footprint of a WRRF is taken up by treatment settling and aeration beds that may be variously configured. While these are normally open to the air, they could potentially be covered by PV canopies, significantly increasing a site's solar capacity. The first canal-top solar PV canopy project was completed in Gujarat, India in 2012 by SunEdison [30]. Canal-top solar PV canopies with an ideal span of 20-25 meters are more expensive than standard solar PV ground mounts [8]. Outside of India, the technology is still nascent. In comparison to canals the contents of digester beds are more chemically active. Additional research will need to be done to determine the technical and financial feasibility of the application of solar PV canopies over WRRF treatment beds and their potential is not included in the present work.

#### *3.1.1. Solar PV System Design at the WRRF*

The system design used to model the potential layout and equipment requirements for solar at the WRRF was produced in Helioscope. The solar was designed to maximize use of available roof space and parking space in order to implement the largest system possible. Losses due to shading, degradation and

[3] When considering roof mounted solar building codes and structural issues need to be investigated and accounted for. These include weight limits, setbacks, and clearances as well as roof type and age of the roof. WRRFs were not built with solar in mind. Therefore, the cost of remediation for the roof to accommodate solar could add significant cost to a project. In addition, there is ambiguity in the wording of the tax code as to how much (if any) of the cost of roof remediation is covered by the federal investment tax credit (ITC).

system setup were included[4]. Weather data in the form of a text file containing hourly and sub hourly solar resources in South Brooklyn over the course of a year was input into the software tool. This system designed produces 782.9 kW DC and 649.6 kW AC of solar power with 1,864 Canadian Solar, CS1U-420MS (1000V)(420W) solar panels and 27 Sunny Tripower 24000TL-US (SMA) inverters with a DC to AC ratio of 1.2. Both rooftop and canopy solar were used in the design as seen below.

Figure 1: Rooftop solar on main building

Figure 2: Solar canopies in south parking lot

Electrical production of this system was modeled in SAM and is summarized in the table and figure below. The lifetime of the solar system was modeled as 20 years with an annual DC degradation rate of 0.5% each year.

### *3.2. Biogas Electricity Generation*

The largest potential energy resource at WRRFs may be the energy within the wastewater itself. Unlocking and extracting this resource through further development of biogas technology has been highlighted as a fundamental component to reaching energy self-sufficiency at WRRFs [9]. Biogas technology is part of the treatment process in which sludge is removed from the liquid stream. After primary and secondary treatments, bacteria cultured in anaerobic digesters breakdown organic materials in an anoxic setting, converting it

[4]Default values for losses were used as no significant shading was identified.

into a digested cake and biogas. This anaerobic digester gas (ADG) consists of 60-65% methane and 30-35% carbon dioxide with traces of other gases. The methane portion can be used onsite to power gas engines to produce electricity or can be refined into what is now coming to be called renewable natural gas (RNG) to be fed into a utility pipeline. Depending on processes, electrical efficiency, and wastewater composition between 25% and 55% of a water resource recovery facility's energy needs can be met with this resource [4]. A potential increase in the amount of biogas is possible from the co-digestion of other organic wastes, such as food waste. The East Bay Municipal Utility District (EBMUD) became energy neutral in 2012, accomplishing this by investing in co-digesting additional feedstocks to fuel on-site combined heat and power (CHP) [10].

*3.2.1. Biogas Generation Design at the WRRF*

The system design for biogas electricity generation is based on the monthly wasted ADG values. Using the values and in the table below an estimate of 5,026,307.93 kWh/yr of energy and an average power generation of 573.78 kW was calculated respectively using equations 1 and 2 respectively.

Table 1: ADG Power Conversion Values

| **Component** | **Variable** | **Value** |
|---|---|---|
| 2018 ADG wasted ($ft^3$) | $W_{ADG}$ | 93,422,464 |
| $ft^3$ to $m^3$ conversion factor | $CF_1$ | 0.0283 |
| Percent of methane (CH4) in ADG (%) | $pct_{CH4}$ | 62.5 |
| CH4 heat value ($MJ/m^3$) | HV | 36 |
| MJ to kwh conversion factor | $CF_2$ | 0.28 |
| Electric Power generated (kW) | $P_{ADG}$ | 1901.4 |
| Electric Energy generated (kWh/yr) | $E_{ADG}$ | 16,656,291.1 |

$$E_{ADG} = W_{ADG} * CF_1 * pct_{ADG} * HV * CF_2 * eff \quad (1)$$

$$P_{ADG} = P_{ADG} \ / \ 8760 \tag{2}$$

An internal combustion (IC) engine, Siemens SGE-36 biogas engine rated at 700 kW of power at 1800 rpm, was chosen. The fuel requirement for the generator chosen is 1796 kW [11]. While the expected fuel generated by the ADG is 1901.4 kW based on the $P_{ADG}$ calculated in equation 2 above. IC engines are commonly used with digester gas and are relatively inexpensive. It is, however, important to account for the cost of maintenance as engine life may be steeply curtailed by elements such as hydrogen sulfide that may be present in the biogas [12]. The system was modeled with a 20-year lifespan, with major engine overhauls included as part of O&M costs.

### *3.3. Energy Storage Systems (ESS)*

The pairing of various ESS technologies to a distributed energy resource can provided added benefits based on the needs of the WRRF, size of the ESS and generation capacity of the paired DER. Long duration ESS such as flow batteries and pumped hydro can increase resilience by providing backup power for days at a time during a power outage. Shorter duration ESS such as lithium ion and lead acid batteries can be used to flatten peak demand, lowering utility bills. Furthermore, all ESS technologies have the potential to provide additional revenue through participation in incentive/contractual programs such as demand response or non-wire solution (NWS) programs.

ESS can be an integral component to a WRRFs load management strategy because of their rapid response capability. They are also scalable, which can accommodate changes to a facility's energy demand. Both peak demand shaving and resilience planning require a properly sized ESS and an optimized battery dispatch schedule in order to most effectively manage the load, which is detailed in the Load Management section.

When determining the requirements of the ESS system there are multiple categories of energy storage systems to consider. These include but are not limited to the following: mechanical, chemical, and electrochemical. Pumped hydro, which is an example of a mechanical ESS, has been around the longest. Pumped hydro also discharges the greatest power for the longest duration; however, without the right geography and access to water, it is not a practical solution. Chemical ESS include fuel cells which, like pumped hydro, discharge a large amount of power for a long duration. However, also like pumped hydro, there are limitations which make it an impractical solution in many cases. Fuel cells are expensive and resources for operation and maintenance can be prohibitive. Electrochemical ESS include supercapacitors, and batteries such as lead-acid, lithium-ion, and flow batteries. Supercapacitors are short duration and are not suitable for load management or resilience. Batteries are the most practical ESS to consider for the WRRF. They are more cost effective than many other alternatives, and do not have specific geographical requirements.

The differences in battery technology affect performance, which can be defined by their output and energy density. Batteries can be used for uninterruptible power supply, load shifting, resilience, and large-scale generation depending on the technology used.

ESS is paired with solar, biogas generation or both solar and biogas generation in the case study scenarios. Regardless of the DER technology that the ESS is paired with, the battery is able to charge from the grid as well as the paired DER. This allows for the most effective use of the battery. Two battery systems were modelled to be implemented in separate scenarios: one for peak demand shaving and the other for resilience. This is because the long duration requirements of an ESS primarily used for resilience requires a different battery technology than is needed for peak demand management. Lithium-ion batteries were chosen to model peak demand management. Lithium-ion batteries are more energy dense than lead acid and thus have a smaller footprint for the same capacity. They also have a higher depth of discharge, longer lifespan, and fewer maintenance requirements. They are the most prevalent battery ESS technology implemented, and the price continues to decrease. The disadvantage of Lithium-ion batteries is that their discharge time ranges from minutes to hours. For resilience the ESS may need to power the load for a day or more. Therefore, the Vanadium Flow Battery (RFB) is an ideal solution for resilience due to its extended discharge time and energy to power ratio. RFB batteries have a long lifetime compared with other battery technologies with minimal to no degradation. However, they are more complex which increases the initial cost of O&M and implementation. They also have lower energy density increasing the footprint of the battery [13].

The size of the ESS is an important consideration if there is a space constraint at the WRRF. There are some technologies that allow for stack-able batteries that can provide space savings. For large-scale lithium-ion batteries a density of 300 MWh/acre and 600 MWh/acre if stackable can be achieved [14]. For smaller lithium-ion solutions, using the Tesla Megapack as a reference, a 970 kW/ 3,878 kWh battery is 9.1m wide, 1.65m deep, and 2.79m high [15]. Whereas for vanadium ESS the footprint is 21m x 17m for a 1MW/ 4.5 MWh battery [16].

## 4. Load Management and ESS Sizing

Electric load management is the systematic management of electricity consumption over a period of time. The facility's load profile may be shaped, either at the base, such as by energy efficiency measures, or at peaks, to reduce demand charges. In addition to the lasting load reduction through energy efficiency, daily load management can occur through load shifting and peak demand shaving. Load management can also be important during power outage events necessitating the prioritization of critical loads.

Load shifting requires performing processes or using large pieces of equipment at different times in order to actively control how much and at what time energy consumption occurs. This process, while cost effective, is not always feasible for facilities that must continuously run processes or have minimal choice as to when certain processes occur, as is the case for WRRFs.

However, load management strategies for peak demand shaving and for resilience during critical events can be implemented using ESS with little to no need for process changes. Optimal ESS sizing and appropriate discharge methods are the focus of the load management analyses below.

Different types of load management objectives require different ESS characteristics. There can be multiple intended purposes for a battery but the primary driver for acquiring the ESS will determine the battery type, size and dispatch method. Therefore, a well-defined use case is essential. The load management use cases analyzed for ESS sizing and dispatch strategy at the WRRF are peak demand shaving and resilience.

*4.1. Peak Demand Shaving*

Peak demand is the highest power demand over a period of time, typically 15 minutes During the course of a month. Monthly peak demand is billed at a high rate by utilities and thus minimizing peak demand can provide substantial savings. Peak demand shaving refers to a strategy intended to take a predetermined portion “off the top.” To make this determination it is necessary to know the size and duration of the peaks in order to create a target reduction level.

Additional plant data was used to determine independent factors causing the peak demand. This data included:

- Effluent Flow, Temperature, BOD
- Influent Wet Well Level and Flow Rate
- Pump Run Status and Cycle Count
- Blower status and
- Pump Runtime Hours
- Power failure and Generator status
- Pump Fail
- Flow totalization

A Pearson correlation showed that daily peak demand was moderately correlated with sewage treated max, r(29) = .57, p ¡ .001. and flow totalization. In addition, in order to understand the relationship between the independent plant variables (listed above) and the dependent variable (peak demand) a linear regression was done. One month of system data was selected to perform the analysis seen in Table 4. The variables with the highest significance (highlighted) were the daily sewage treatment max and sewage flow. This data is compares to favorably to the observation that peak demand is higher on rainy days and provides the explanation that increased sewage flow due to rain water is a probable cause.

*4.1.1. Peak Demand Shaving - ESS Sizing Considerations*

The figure below shows a generic facility's load profile to illustrate the height and duration of demand peaks that can occur throughout the day. This information can be used to determine the appropriate battery size to reduce the peaks. The required battery power (kW) is determined by the difference between the target demand level and the peak demand level. The battery capacity (kWh) is determined by the duration of the peak in hours.

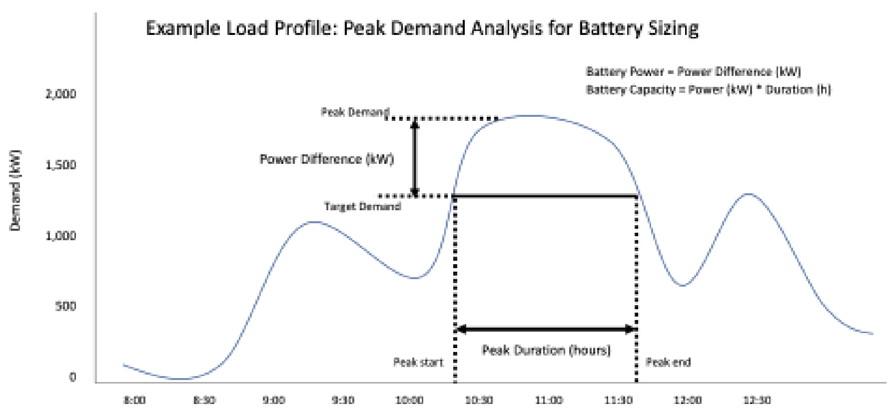


Figure 3: Example of Battery sizing for demand shaving based on a load profile (not specific to or characteristic of wastewater plants).

However, in general, the load profile of WRRFS show a much flatter pattern, with less pronounced peaks, due to the continuous nature of their flows and processes. This is illustrated in the figure below. While the WRRF load profile does vary from month to month over the course of a year there is a consistent trend that precludes the use of standard means of determining the size of the ESS as described above. The load profile of the three days in March 2018 shown below is illustrative of these trends as described below.

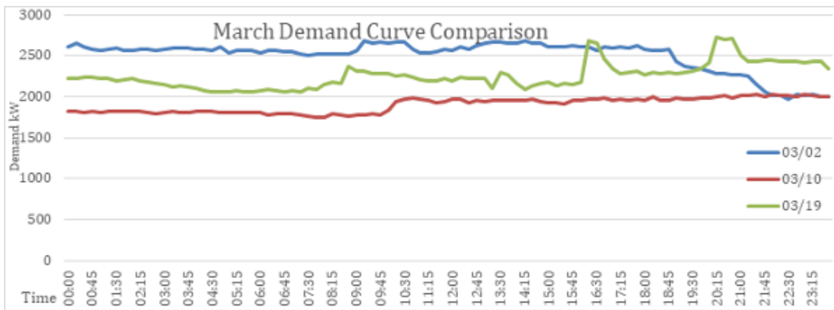


Figure 4: Comparison of demand at the WRRF over 3 days in March 2018

Three days are compared above:

1. A rainy day with high demand all day (3/02 - blue line)
2. An average day during the month with relatively flat demand. (3/10 - red line)
3. The peak demand day (no-rain) (3/19 - green line)

March 2nd was a rainy day with continuously high demand throughout the day (approximately 25-30% higher than the monthly average). This increase in demand on rainy days is due to the additional inflow of stormwater that must be processed (Appendix A). The monthly peak demand day (3/19) was not rainy. However, on 3/19 there were two short-duration demand peaks. Investigation with the facility's operator revealed that system and equipment tests were being performed on that day, accounting for the peaks. Therefore, it is not practical to have a battery fully mitigate rainy day peaks due to their magnitude and duration. Monthly peak demand days caused by system and equipment testing may mitigated by strategic planning. Operators should plan equipment testing at times of minimal demand or else be sure to discharge ESS during testing.

The shape of the load profile for WRRFs prevents sizing the ESS using the usual considerations for peak demand shaving due to the long duration of peaks. Therefore, an alternative criterion was required to identify an optimal battery size. Simple payback was used as alternative method for ESS sizing optimization. The simple payback was determined for multiples ESS sizes using the parametric functionality in SAM. The size with the shortest simple payback period was then selected for use. The ESS sizes compared were limited to an energy capacity of 4 hours, which is the minimum necessary to participate in most demand response incentive programs, and power ratings between 500 kW and 3000 kW in increments of 100 kW. This created 26 ESS combinations where the system costs, bill savings, and incentive revenues were optimized to determine the ESS size with the shortest simple payback time. A summary of outputs for each ESS size are provided in Appendix B-2. This analysis identified a battery with a power rating of 2100 kW and 8400 kWh with a simple payback of 10.7 years as the optimal size for the WRRF.

*4.1.2. Demand-Shaving - ESS Dispatch Strategy*

An ESS performs load management through the controlled charging and discharging of the battery at certain times to meet the goals of the load management strategy. These goals can include overall peak demand reduction, availability and dispatch of demand reduction for incentive/contract requirements, opportunities from time-of-use (TOU) rates, and resilience targets. Battery dispatch schedules are used to manage when the battery should charge and discharge to optimize economic performance.

SAM determines an optimal battery dispatch schedule based on a comparison of several alternatives, in each case discharging the battery if demand is higher than target power and charging it if demand is lower than the target power. SAM requires at least one generation source to be included with all ESS system models, including charging the ESS from the grid. For our analysis only PV was included as the on-site generation source to create an initial simplified model to determine the most appropriate dispatch strategy. Further detail on the SAM dispatch modeling is provided in Appendix B-1.

Four battery dispatch strategies for a solar plus storage system were analyzed : Look ahead, Look behind, Manual dispatch and Grid power target. The results of the SAM dispatch analysis, shown in Appendix B-2, indicate that the choice of Dispatch Strategy can make a 5-10% difference in the demand reduction realized. The Look Ahead strategy consistently provided the greatest demand shaving, with the lowest average peak demand as well as the lowest overall peak monthly peak demand. This dispatch strategy was then used when running the parametric simulations to determine the optimal ESS size for the WRRF demand response scenarios as well as the financial models. The results from the SAM dispatch modeling is provided in Appendix B-2.

### *4.2. Resilience*

Resilience is the ability to maintain critical services during an emergency power outage. This can be done through on-site power generation via renewable sources, emergency generators, ESS or a combination of all three. In order to accurately plan resilience measures it is important to know the size of critical loads and the expected duration of the outage.

#### *4.2.1. Resilience - ESS Sizing Considerations*

Resilience during emergency events is increasingly necessary as climate change increases the frequency of severe weather events. This is demonstrated yearly worldwide with the increased occurrences and severity of hurricanes, wild fires and flooding. When emergency events affect large metropolitan areas, the environmental and economic damage can be devastating.

Resilience can be achieved through conventional generators which burn diesel or natural gas, or through the use of a combination of renewable energy generation and ESS. The WRRF currently has two diesel-fueled engine emergency generators. These generators are cost effective as they have already been purchased and the only additional costs are maintenance and fuel. However, maintenance on generators that are rarely used can be problematic and costly, in comparison with equipment that runs on a regular basis.

Although costly, addition of PV and ESS to the emergency preparedness/resilience capabilities of the WRRF can be considered to have several benefits. During an extended event, generators are vulnerable to the availability of fuel supplies that may also be interrupted. ESS in conjunction with on-site renewable energy is not reliant on vulnerable fuel supplies. The ESS may make it possible to ride-through delays in fuel delivery. ESS, as a complement to diesel generation, may also be more suitable for daily use in demand reduction, provision of spinning reserve capacity, and other alternate-wire programs that can bring financial benefits. Daily use of diesel generators would have a high carbon footprint and local emissions loading, while ESS would be in line with policy objectives of reducing CO2 emissions (eventually to zero) to mitigate climate change and reducing particulate air pollution from combustion to improve public health.

The ESS sized for resilience was based on peak demand values. The average monthly peak demand for 2018 (the latest year for which full hourly (8760) demand data is available) was 2.84 MW and the maximum monthly peak demand was 3.27 MW. Critical loads account for approximately 79% of the facility's daily load. Therefore, to cover the critical load during max peak demand approximately 2.5 MW of power is needed. The ADG produced will cover 513 kW (20%) of the critical load energy demand. A battery can be used to cover the remaining critical demand (2 MW) for 10 hours. Using equation 3 below it is determined that with a depth of discharge of 85% and round trip efficiency of 80% that a 3MW (30 MWh - to cover 10 hours) battery is needed to meet this requirement [13].

$$BESS\,Power\,(MW) = \frac{power\;required\,(MW)}{depth\,of\,discharge\,(\%)\,*\,battery\,efficiency\,(\%)} \tag{3}$$

In addition, if solar resources area available, the facility will be able to maintain services for a longer duration in the event of a grid emergency.

*4.2.2. Resilience - ESS Dispatch Strategy*

An appropriate dispatch model during emergency power outage events is important in order to maintain critical and essential services during emergency events. Understanding and prioritizing building and process loads is key to designing and implementing a dispatch plan to cover loads necessary for continued service.

Loads can be categorized into critical loads and non-critical loads, where critical loads are those that are needed to maintain key operations and may require uninterrupted power. Criteria used to determine whether a load is critical or not can include financial penalties, service provision, health and safety, security and reputational damage. The power demand and duration of coverage should then be assessed after the critical loads have been identified. Non-critical loads are loads that, while useful during non-emergency events, can be eliminated during power outage events. These non-critical loads can be further divided into essential and non-essential loads. Where essential loads provide important secondary services that are not critical. An example breakdown of critical and non-critical loads for a water resource recovery facility can be seen below in the table below.

Table 2: Potential Critical and Non-Critical Loads for a WRRF

| Critical Loads | Non-Critical Loads | |
| --- | --- | --- |
| | Essential Loads | Non-Essential Loads |
| Influent pumping | Secondary clarifier and return activated sludge (RAS) | Building systems |
| Effluent filters and processes | Thickening and sludge pumping | Solids dewatering |
| Secondary treatment aeration [5] | | |
| Primary clarifier and sludge pumps | | |

These loads can be managed using a critical load panel. A critical load panel is a separate electrical panel that supplies critical loads and where the ESS or emergency generation capacity is connected to ensure uninterrupted power during an outage.

### *4.3. ESS Design at the WRRF*

The battery used for peak demand shaving is a lithium ion NMC/Cobalt battery with 8400 kWh capacity and 2100 kW power. The battery used for resilience is a Vanadium RFB with 30 MWh capacity and 3 MW power. The project lifetime is modelled at 20 years with battery replacement required when the battery capacity drops to 50%. The estimated lifespan of the vanadium battery is 20 years [16]. Also, based on expected usage the lithium-ion battery is not replaced in any of the scenarios. The model limited the minimum state of charge to 20% and the maximum state of charge to 100% for both battery technologies. While there are many potential providers of large scale ESS available, the current model does not assume a specific ESS supplier and instead uses average price projections provided by NREL for system costing. A discussion on the dispatch method used for ESS sizing can be seen in Appendix B.

Table 3: Battery System Design

| **Use Case** | **Technology** | **Capacity (kW)** | **Power (kWh)** | **Replacement Capacity (%)** |
|---|---|---|---|---|
| Peak Demand Shaving | Lithium-ion | 2100 | 8400 | 50 |
| Resilience | Vanadium RFB | 3000 | 30000 | 50 |

[5] During extended outages secondary treatment aeration may be treated as a non-critical load in order to maximize facility up time.

## 5. Costs, Revenues and Project Finance

### *5.1. System Costs*

System costs for the WRRF project can be broken out into two parts: 1) capital costs and 2) Operations and Maintenance (O&M) costs. Insurance for all scenarios is paid annually and estimated as 0.25% of the total capital cost. The costs associated with financing are dependent on the financing methods chosen rather than the system design and will be discussed further in the financing options section. It was assumed that there would be no additional cost for real estate purchases or leasing, or site remediation for the WRRF.

Table 4: System Costs Summary

| **Use Case** | **Capital Costs** | **O&M Costs (20 years)** |
|---|---|---|
| Solar plus Storage | $4,494,360 | $2,034,893 |
| Biogas (standalone) | $2,263,161.25 | $3,535,091 |
| Biogas and Solar | $3,433,349.75 | $4,253,479 |
| Biogas, Solar plus Storage | $7,303,963.00 | $5,683,910 |
| Resilience | $26,429,694.00 | $8,854,254 |

#### *5.1.1. Capital Costs*

the WRRF's energy storage system costs were determined using NREL's 2020 battery storage cost projections [17]. The PV system costs were determined by using NREL's U.S. PV system costs Q1 Benchmark [18] figures for a commercial PV system. Solar and ESS costs were combined as the ESS was not modelled as a standalone system, but instead was paired with either solar alone or solar and biogas combined. The biogas generation costs were derived from the 2017 EPA Catalog of biogas generation Technologies Report [19]. These costs were modelled separately as there is a standalone biogas generation scenario analyzed. These costs were then added to the solar and ESS costs to provide the capital costs for the combined biogas, solar and biogas, solar plus storage scenarios.

When estimating the PV capital costs the NREL system used for benchmark pricing was a 200 kW DC system in New Jersey. Both of the NREL papers mentioned above also showed two trends: 1) the price per watt decreases as the system size increases, and 2) the year-on-year cost of PV is declining. Therefore, the costs used for the WRRF are a conservative estimate of the potential system cost, as the actual cost will likely be lower due to the aforementioned trends. The total installed cost for solar plus storage is estimated to be \$3.63M at \$5.71/W DC of solar. The battery cost is calculated to show the cost in relation to the solar size (\$3.95/W of solar), so that a total price per watt of solar can be determined. However, when the battery is priced per watt of battery power, the battery cost is \$1.57/W. The cost breakdown for solar and ESS can be seen in the figures below.

#### *5.1.2. Operating Costs*

Operations and Maintenance (O&M) costs vary by technology. Solar and Storage O&M costs for the Lithium-Ion battery used for peak demand shaving are projected to be \$27/kW-yr with a 2% escalation rate plus a flat rate of \$48,000/yr. Biogas generation O&M costs are estimated at \$19/MWh with a 2% escalation rate.

### *5.2. Revenue: Incentives and Bill Savings*

Project revenues come from both savings in billed energy and from incentives, which may take the form of incentives or contracts. Incentives can come from city, state and federal governments usually via tax credits. Utility companies can also provide incentives as special programs or contract opportunities. Incentives and savings that are available for the WRRF include: 1) the Federal ITC, 2) Demand charge management, 3) NYISO demand response programs, 4) The utility's demand response programs, 5) VDER, 6) Spinning Reserve, and 7) Non wire solutions programs. A summary of the estimated incentive payments

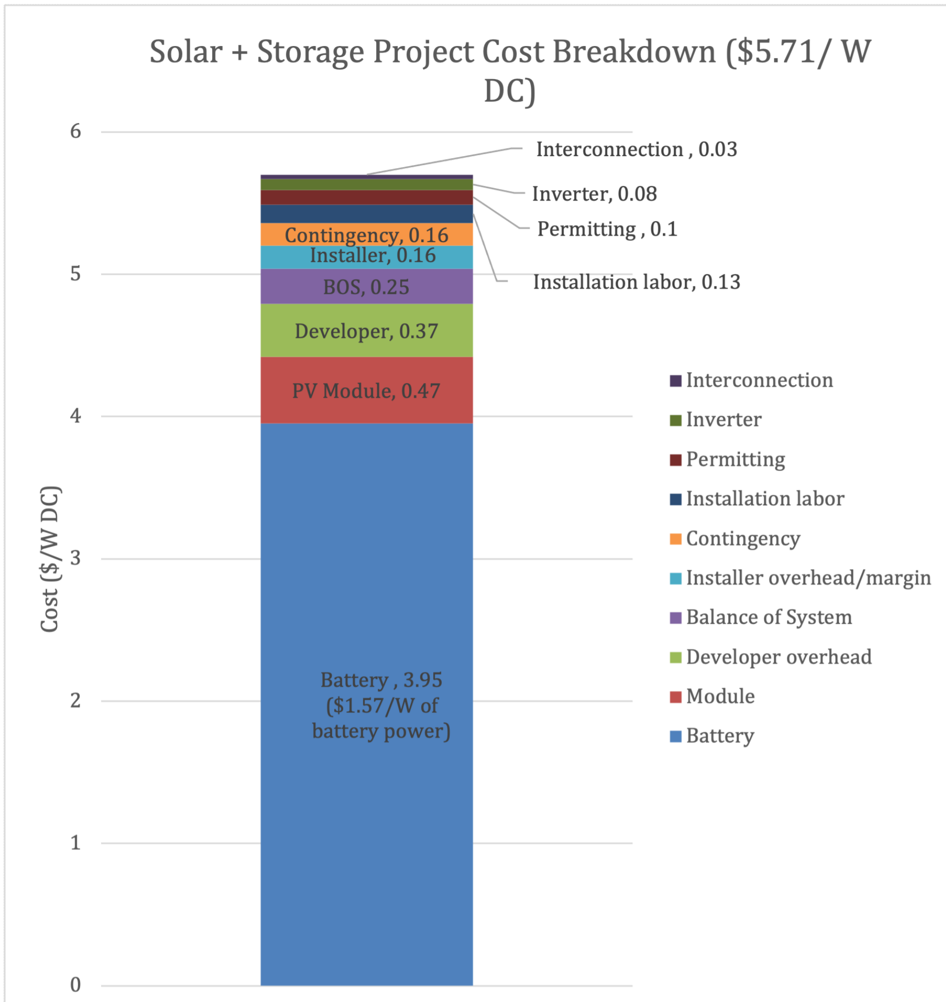


Figure 5: Detailed breakdown of solar and storage cost for the WRRF's proposed system)

for each case study scenario can be seen below. The non-wire solutions program was found inapplicable as certain provisions conflicted with assumptions in the operating scenarios modeled. Incentive calculations are detailed in Appendix C along with descriptions of each of the Incentive Programs.

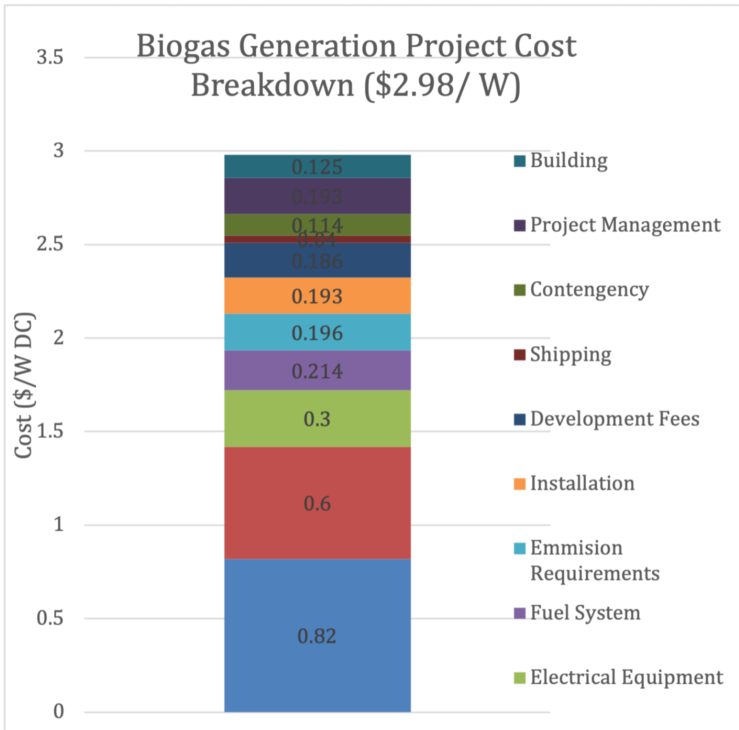


Figure 6: Detailed breakdown of biogas generation cost for the WRRF's proposed system

We note that municipal governments may not be eligible for federal tax credits, such as ITC, since they pay no taxes. A mechanism must be applied wherein private investors are able to participate, taking advantage of the tax credit. The project finance industry has many examples of such mechanisms in other fields such as low-income housing development.

### *5.3. Financing Options*

There are multiple ways to finance DER + storage systems. The financing method can greatly affect the cost of a project [20]. The main reasons for

[6]Resilience scenario is only modelled for Debt/ Equity financing.
[7]ITC incentive values are based on . ITC is not applicable when the WRRF finances with Debt and Equity because the WRRF does not have a tax liability for the ITC to offset.
[8]For PPA the Incentive goes to the 3rd party system owner not the WRRF

Table 5: Revenue Summary (Incentives and bill savings)

| Incentives | System Design Scenarios | | | | |
|---|---|---|---|---|---|
| | Solar + Storage | Biogas only | Biogas + Solar | Biogas, Solar + Storage | Resilience [6] |
| Federal ITC ($) [7], [8] | $1,197,576 | $651,556 | $651,556 | $1,849,132 | N/A |
| Demand Charge management ($/yr) | $285,073 | $1,456,107 | $1,456,107 | $1,725,580 | $1,819,158 |
| ISO SCR Capacity Payment ($/yr) | $84,751.75 | N/A | N/A | $162,999.50 | $0 |
| Utility CSRP Capacity Payment ($/yr) | $38,138.29 | N/A | N/A | $73,349.78 | $0 |
| Utility DLRP Capacity Payment ($/yr) | $52,969.84 | N/A | N/A | $101,874.69 | $0 |
| VDER ($/yr) | N/A | N/A | N/A | $184,756 | $822,953 |
| Spinning Reserve | N/A | N/A | N/A | N/A | $395,850 |

these differences are transaction costs, financial parameter assumptions such as discount rates, and IRR, and contract terms for both debt and equity [21].

While cash can typically provide the most savings to the system owner/ host, there are certain circumstances where this is not the case or when the customer does not have the cash and cannot arrange debt financing to purchase the entire system. Financing methods can be used alone or in conjunction with other methods. A common financial structure combines debt (loans/ bonds) and equity (cash). Below are three of the more common ways to finance a project.

- Municipal Bonds (Debt): The most traditional and common way of funding improvements at WRRFs is through municipal bonds. These bonds are issued by municipalities or authorities for a finite amount of money, usually for a time period of 20 years. Most municipalities have their bonding capacities established by the state.

- Commercial Loans (Debt): Commercial loans from private banks can be obtained to finance energy-saving projects with short payback periods. Equipment purchases may qualify for low-interest commercial loans as well.

- Power Purchase Agreement (PPA): Financial arrangement in which a third-party developer owns, operates, and maintains the PV system, while a customer hosts the system on its property and purchases the electric output from the developer for a predetermined period. The energy tariff negotiated between the developer and host is called the PPA rate, and is the price for the energy generated ($/kWh). This financial arrangement allows the host customers who do not pay federal taxes to still receive a portion of the savings from the federal tax credit, which is passed through by the developer.

Costs for financing were also taken into consideration in the debt/equity model. The loan rate of 4.8% was taken from NREL's system cost benchmark [22] and the inflation rate of 3.22% is provided by the Bureau of Labor and Statistics Consumer Price Index Unadjusted figures [23]. The real discount rate is approximated using the tax-free rate of return on 20-year US treasury bonds of 2.04% [24].

In the PPA model the same financial considerations were taken as in the debt/equity model to maintain consistency in the comparison of the models. In addition, the PPA requires the added cost of financing that is involved when dealing with a third party. Debt closing costs of $300,000 for all 3 scenarios analyzed (solar plus storage, biogas generation, biogas generation and solar plus storage). The development fee for the solar plus storage case was estimated at $30,013. The addition of biogas generation increased the development fee to

$384,054 [11]. Equipment replacement reserves, which is paid by the investor is estimated to be $158,961 based on a replacement cost of ($.25/W) for solar plus storage. Equipment replacement reserves are not calculated for biogas generation and are included in the yearly O&M costs.

## 6. Results

### *6.1. DER Generation Results*

The generation profile of the various distributed energy resources is seen in the following charts. Each chart demonstrates the DER generation for types of days typical of a WRRF. These days include:

1. A rainy day with high demand all day. (3/02)
2. An average day during the month with relatively flat demand.(3/10)
3. The peak demand day (no-rain) (3/19)

The ADG generation is flat as the ADG production is constant throughout the day. The solar generation varies in relation to solar availability and can be seen to start around 7:00am, peak near noon and end at approximately 5:00pm. The battery discharges only to mitigate the peak demand, so on average days there is no discharge and only on the peak demand day can the battery be seen to be actively charging and discharging to curtail the peak based on the dispatch strategy chosen. This lowers the electricity load seen in red to the actual bill load indicated by the blue line.

### *6.2. Financial Analysis Results*

When analyzing system design options for Red Hook, five scenarios were taken into consideration:

1. Solar + Storage,

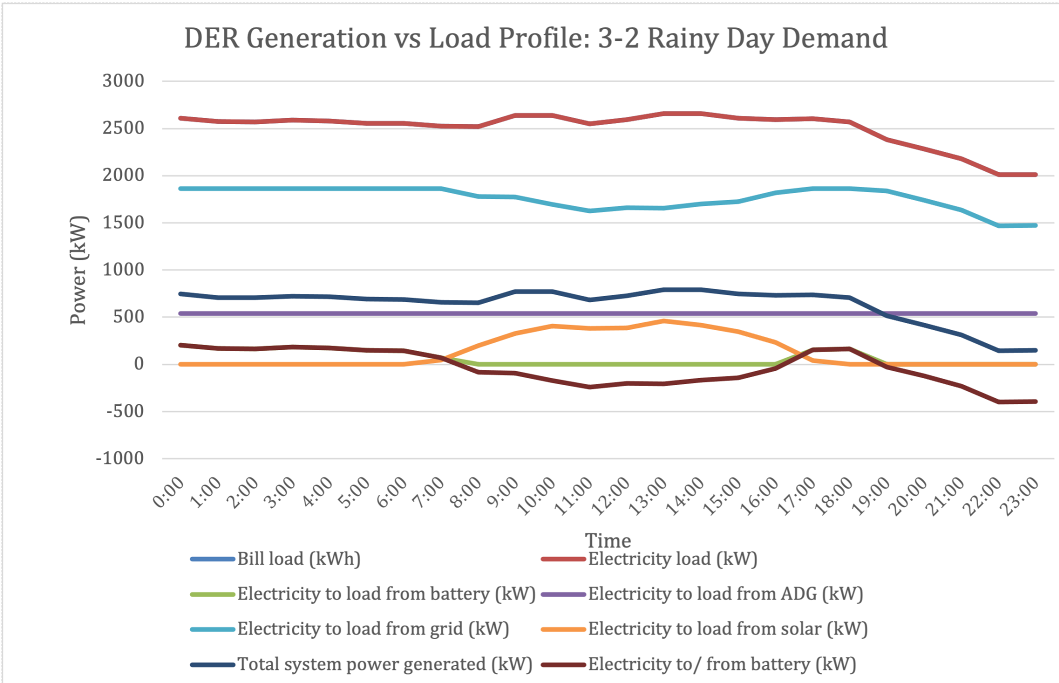


Figure 7: Generation Profile vs Load Profile of the WRRF on 3-2-2018 (rainy day)

2. Biogas generation alone,
3. Biogas with solar,
4. Biogas with Solar + Storage, and
5. Resilience

Each of these scenarios, with the exception of the Resilience scenario, was in turn analyzed with two different financial models. PPA financing with Resilience was not feasible due to the large battery size in relation to amount of energy generation. Therefore, only debt/equity was modelled.

For each scenario, first a debt/equity model was created with 60% debt and 40% equity to ensure at least a 1.3 debt service coverage ratio. The second financial scenario modeled was a power purchase agreement (PPA) with debt (also a 1.3 debt service coverage ratio). The target IRR for each PPA scenario was 11% in 20 years. The System Advisor Model determined the appropriate

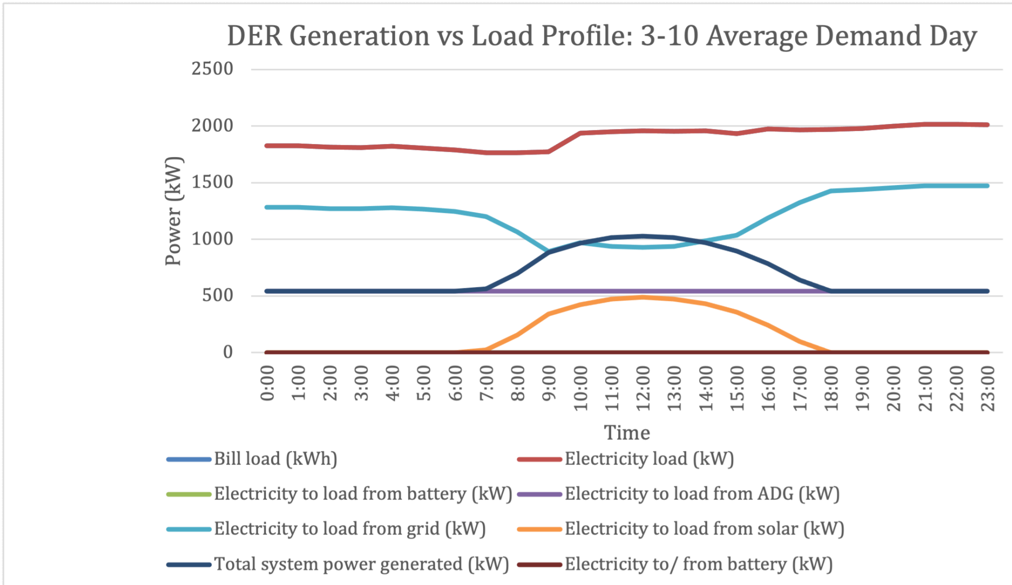


Figure 8: Generation Profile vs Load Profile of the WRRF on 3-10-2018 (Average Day)

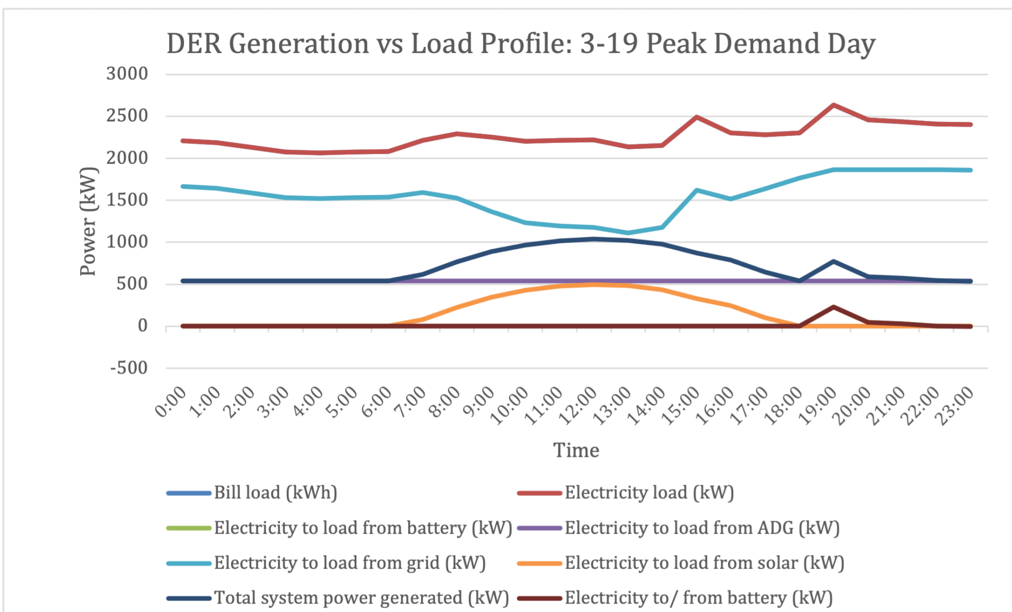


Figure 9: Generation Profile vs Load Profile of the WRRF on 3-19-2018 (Peak Demand Day)

PPA price needed to reach the target IRR within the specified time frame. The result of the financial analysis of each of the models can be seen the table below.

| | | System Design Scenarios | | | | |
|---|---|---|---|---|---|---|
| | **Size** | **Solar + Storage** | **Biogas Only** | **Solar + Biogas** | **Biogas, Solar + Storage** | **Resilience** |
| System Specifications | Solar PV (kW DC) | 782.9 | N/A | 782.9 | 782.9 | 782.9 |
| | ESS (kWh - kW) | 8.4MWh - 2.1 MW | N/A | N/A | 8.4MWh - 2.1 MW | 72 MWh - 3 MW |
| | Gas Engine (kWe) | N/A | 676 | 676 | 676 | 676 |
| | Yr1 Generation (kWh) | 1,092,159 | 5,497,288 | 6,589,447 | 6,589,447 | 6,589,447 |
| | **Cost** | | | | | |
| | Installed Total ($) | $4,594,360.00 | $2,263,161.25 | $3,433,349.75 | $7,303,963.00 | $26,429,680 |
| | Price per watt ($/W-DC) | $5.86 | $3.35 | $2.59 | $5.51 | $19.95 |
| Financing Specifications | **PPA** | | | | | |
| | PPA Price (¢/kWh) | 45.56¢ | 6.76¢ | 9.97¢ | 18.35¢ | N/A |
| | Escalation Rate (%/yr) | 1 | 1 | 1 | 1 | N/A |
| | DSCR | 1.3 | 1.3 | 1.3 | 1.3 | N/A |
| | **Debt/ Equity** | | | | | |
| | 60% Debt Value ($) | $2,756,616.00 | $1,357,897.00 | $2,060,010.00 | $4,382,378.00 | $15,857,808.00 |
| | Loan Rate (%) | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 |
| | Term (Yrs) | 20 | 20 | 20 | 20 | 20 |
| Financial Analysis | **Financial Metrics** | | | | | |
| PPA | Host NPV ($) | ($1,013,406) | $857,585 | ($1,350,467) | ($3,369,057) | N/A |
| | Developer NPV ($) | $646,378 | $127,745 | $1,472,136 | $3,242,789 | N/A |
| | Cash Flow Yr1 ($/y) | ($162,561) | $22,647 | ($214,901) | ($471,208) | N/A |
| | Revenue - Bill Savings ($) | $335,491 | $394,520 | $444,849 | $737,495 | N/A |
| | Expenses - PPA Price ($) | $498,052 | $371,873 | $659,750 | $1,208,703 | N/A |
| Debt/ Equity | NPV | $421,786 | $1,967,713 | $1,176,868 | $2,467,341 | ($10,733,516) |
| | Cash Flow Yr1 ($/y) | $140,830 | $177,293 | $148,082 | $319,132 | -172254 |
| | Revenue ($) | $438,930 | $394,520 | 444,849 | $860,910 | 1269796 |
| | Bill Savings ($) | $335,491 | $394,520 | 444,849 | $737,495 | $750,210 |
| | Incentives ($) | $103,439 | $0 | $0 | $123,415 | $519,586 |
| | Expenses ($) | $298,100 | $217,227 | $296,767 | $541,778 | 1442050 |
| | Debt Repayment ($) | $217,463 | $107,121 | $162,509 | $345,715 | $1,250,982 |
| | Total Operating Exp. ($) | $80,637 | $110,106 | $134,258 | $196,063 | $191,068 |

Figure 10: Summary of System Design Specifications, Financial Terms, and Results for Red Hook WRRF

## 7. Discussion

When analyzing project options for the WRRF, three system scenarios were taken into consideration: Solar + Storage, biogas generation alone, and biogas with Solar + Storage. Each of these scenarios was in turn analyzed with two different financial models. First a debt/equity model was created with 60% debt and 40% equity to ensure at least a 1.3 debt service coverage ratio. The second financial scenario modeled was a power purchase agreement (PPA) with debt (also a 1.3 debt service coverage ratio). The target IRR for each PPA scenario was 10% in 10 years. The System Advisor Model determined the appropriate PPA price needed to reach the target IRR within the specified time frame. An overview of the models can be seen the table below.

### *7.1. Financial Analysis: Solar + Storage*

When looking at a debt and equity financed solar and storage project for the WRRF there is a net present value (NPV) at the end of the project life (20 years) of $421,786. The cashflows that make up the NPV are generated by the yearly utility bill savings and incentive payments. The year one bill saving totals $331,491. The year 1 incentive revenue generated from the ISO and the utility's demand response incentives totals $103,439 which is due to an average of 414 kW demand reduction commitment. The detailed incentive amounts can be seen in Appendix C. The yearly revenues were offset by the debt service payment of $217,462/year. The yearly system expenses, which consist mainly of operations and maintenance and insurance totals $80,637 in year 1. The remaining cash flow in year 1 is $140,831. This yearly positive cash flow leads to the positive NPV over the 20-year lifetime of the project.

When financing with a third party PPA agreement, the WRRF's investment has an NPV of $-1,013,406, while the developer's investment has an NPV $646,378. A developer IRR of 11% after 20 years was targeted which required a PPA rate of $0.4556/kWh with a 1% yearly escalation rate. This PPA rate is higher than the current utility rate paid. However, the PPA rate includes the cost of the ESS which is 69% of the system cost. Therefore, additional costs not associated with a proportional increase in power production, will cause the PPA rate to increase. The PPA payment in year 1 for the energy produced by the system is $498,052. With the addition of storage, the monthly peak demand is shaved slightly, which causes the bill savings discussed previously. The bill savings is completely offset by the PPA payment, which results in a negative NPV for the WRRF. The demand response incentive goes to the developer, who is the owner of the system, which provides a significant portion of their NPV in addition to the one-time ITC payment of $350,170 in year 1. However, as the owner, the developer is also responsible for operation expenses, which offset the revenue earned. Of the 2 scenarios described above, the Debt/ Equity scenario provides the best return on investment for the WRRF.

*7.2. Financial Analysis: Biogas generation Only*

When looking at the biogas generation project for the WRRF, financing with a combination of debt and equity provides a net present value (NPV) at the end of the project life (20 years) of $1,967,713. The cashflows that make up the NPV are generated by the yearly utility bill savings of $394,520 (in year 1). There are no incentives available for this project because without ESS demand response reduction cannot be guaranteed. The scenario modelled the biogas generation system offsetting 5,497,288 kWh of the WRRF's 16,414,029 kWh load for the year. This accounts for 33.5% of their total load. Not only does this decrease the WRRF's utility bill based on their overall decreased energy usage, the constant power supplied also decreases peak demand which in turn lowers the monthly demand charge. Even with debt service payments of $107,121 and operation expenses of $110,106 the after tax cash flow at the end of the year is $177,292.

When financing with a third party, the PPA rate of $0.676/kWh with a 1% yearly escalation rate is used to generate an 11% IRR after 20 years. This PPA rate provides a developer NPV of $127,745. The utility bill savings is offset by the PPA payment of $371,873 (in year 1). This gives the WRRF an NPV of $857,585.

Of the 2 scenarios described above, the debt/equity purchase provides the best return on investment for a biogas generation only system with a positive NPV and significant bill savings. PPA financing also provides a viable option if debt and equity procurement is not feasible.

### *7.3. Financial Analysis: Biogas generation + Solar*

When looking at the biogas generation plus solar project for the WRRF, financing with a combination of debt and equity provides a net present value (NPV) at the end of the project life (20 years) of $1,176,868. The cashflows that make up the NPV are generated by the yearly utility bill savings of $444,849 (in year 1). There are no incentives available for this project because without ESS demand response reduction cannot be guaranteed. The scenario modelled the biogas generation system offsetting 6,589,447 kWh of the WRRF's 16,414,029 kWh load for the year. This accounts for 40% of their total load. Not only does this decrease the WRRF's utility bill based on their overall decreased energy usage, the constant power supplied also decreases peak demand which in turn lowers the monthly demand charge. Even with debt service payments of $162,509 and operation expenses of $134,258 the after tax cash flow at the end of the year is $148,082.

When financing with a third party, the PPA rate of $0.676/kWh with a 1% yearly escalation rate is used to generate an 11% IRR after 20 years. This PPA rate provides a developer NPV of $1,472,136. The utility bill savings is offset by the PPA payment of $659,750 (in year 1). This gives the WRRF an NPV of $-1,350,467.

Of the 2 scenarios described above, the debt/equity purchase provides the best return on investment for a biogas generation plus solar system with a positive NPV and significant bill savings.

### *7.4. Financial Analysis: Biogas generation + Solar + Storage*

When looking at biogas generation combined with solar and storage for the WRRF a combination of debt and equity provides a net present value (NPV) at the end of the project life (20 years) of $2,467,341, and a simple payback period of 9.9 years. The cashflows that make up the NPV are generated by the yearly utility bill savings, incentive payments, and VDER credits. The year one bill saving totals $737,495. The year 1 incentive revenue generated from the ISO and the utility demand response incentives totals $123,415. The debt service payment of $345,715/year and the system expenses, consisting mainly of operations and maintenance and insurance, of $196,063 (year 1) is not enough to entirely offset the revenue and savings generated. There is a year 1 after tax cash flow of $319,131, which accounts for the positive NPV.

When financing with a third party, a target IRR of 11% after 20 is set, which results in a PPA rate of $0.1835/kWh with a 1% yearly escalation rate. This provides a developer NPV of $3,242,789. The significant bill savings is completely offset by the PPA payment of $1,208,703 giving the WRRF an NPV of $-3,369,057 at the end of the project life. The debt/equity purchase provides the best return on investment.

### *7.5. Financial Analysis: Resilience*

When looking at storage sized for resilience (3MW power and 30 MWh capacity) in combination with biogas generation and solar plus storage for the WRRF only debt and equity was considered. The standard PPA model calculates the PPA price based on the amount of energy the system will generate. However, when the ESS is larger than the generation, then a new pricing model is needed to accurately model a practical PPA scenario. This analysis is done in a future paper.

The large size of the ESS can be used to take advantage of additional incentive programs when not used for resilience. This includes spinning reserves which can bring in a variable amount of revenue based on the market price, and the amount of time the ESS is reserved. This scenario used 5 10-minute commitments for 200 days, which brought in an estimated $292,320/year. This is a conservative estimate. Further analysis would need to be done to take into consideration cost of recharging the batter and battery degradation to determine the optimal spinning reserve commitment. This incentive has the potential to provide significant additional revenue.

The NPV at the end of the project's life is $-10,733,516. This is due to the high cost of the ESS used for the system. When considering only the typical financial outcomes the resilience scenario is a good choice for the WRRF. However, resilience has many ecological and societal benefits that are not quantified in a standard financial analysis. These include reduced greenhouse gas emissions, minimization of sewage dumping due to power outages which mitigates the cost of associated fines and environmental cleanup. These benefits may prove consequential enough to offset the substantial cost of the system.

### *7.6. Sensitivity Analysis*

A comparison of net present value (NPV) is used to determine the best financial scenario for the WRRF. NPV is a measure of financial feasibility that takes into consideration the project cash flows over the lifetime of the project. The main factors for cash flow are the revenue generated and the costs. The revenue generated comes from bill savings and incentive programs. The costs can include operations and maintenance, insurance, capital costs and debt servicing costs. A sensitivity analysis is done on the largest drivers of the costs and revenues of the project and discussed below. The sensitivity analysis is performed using NREL's System Advisor Model's Stochastic functionality. A normal distribution is used. For each input variable a mean and standard deviation are provided. The output variable for each scenarios is NPV.

#### *7.6.1. Interest Rate*

Interest rate is the cost of debt of project. A higher interest rate requires a larger proportion of cash flow that goes towards debt repayment. Changes in interest rate can change NPV. In all scenarios a loan rate of 4.8% is used over a 20 year debt term with 60% of the project cost being financed with debt. For the sensitivity analysis of the interest rate the mean used is 4.8% and the standard deviation used is 0.72.

Changes is interest rate do not measurably change the outcome of the financial analysis. While NPV is lower with higher interest rates, all scenarios are affected equally. Therefore, the biogas, solar plus storage scenario is still the best scenario regardless of the interest rate. The most notable change is that at the lowest interest rate, 2.9%, there were no scenarios with a negative NPV.

#### *7.6.2. Battery Cost*

In the solar plus storage scenario battery costs make up more than 70% of the installation costs. When biogas is included in the scenario, the batter costs as a percentage is lower; however, it still remains above 50%. Therefore, a sensitivity analysis is done on battery cost to determine the change in financial feasibility if battery prices are to significantly increase or decrease. The biogas standalone and biogas plus solar scenarios do not have storage and so are not included in the analysis. In all scenarios a price of $383.67/kWh is used for the battery. For the sensitivity analysis of the battery cost a mean of $383.67 is used and a standard deviation of $57.55 is used.

Changing the cost of storage has a measurable change on the NPV. When the battery cost is increased all scenarios have a negative NPV with the exception of the biogas, solar plus storage debt/equity scenario. The battery costs ranged from $200 to $520.

## 8. Conclusion

Our analysis, as summarized in Table 14, suggests that renewable energy installations can be cost-effective at WRRF, even with their limited opportunity for peak-demand shaving, when all eligible sources of project revenue are captured and applied. Reasonable ROI and positive NPV are achieved in most scenarios, although with some considerable differences in magnitude. The scenario at the WRRF with the highest net present value and yearly cash flows combines solar, storage and biogas generation when financed with debt and equity. Bill savings and demand response incentives play a key role in giving the debt and equity scenarios a higher NPV and cash flow than their PPA counterparts even though the WRRF could not take advantage of the ITC. A properly sized ESS plays a key role in maximizing demand reduction and is mandatory to participate in demand response programs since many programs require a minimum amount of demand reduction sustained over a long duration of time. ESS also provides resilience during emergency power events.

The Resilience Scenario is substantially more expensive than the other three, due to its greatly increased ESS size. The enlarged ESS has a great deal of social utility, which is not captured in the project revenues and overall economics. Without a monetary valuation of the social benefits, the project can no longer be effectively financed through a PPA – the price to be charged per kwh would be too high. Nevertheless, there is the possibility for resilience to provide non-financial benefits to the population being served. Government has a much lower expectation for return-on investment than the private financing of a PPA.

The best-case combination of PV-biogas generation-ESS has greater residual value to the municipal owner when financed using debt-equity. This assumes that adequate funding would be available for the larger project. In the absence of public equity finance, however, the municipality would require access to a PPA, in which there is no initial investment by the municipal owner. In this case, the choice of technology shifts, as we see that under this form of finance, the biogas-generation project alone has the highest NPV and would therefore be the investor's first choice. It is interesting to note that the financing mechanism may make a difference in the choice of technology, leading to much reduced long-term benefit to the public.

### *8.1. Future Work*

We will address further aspects of the work in future papers. Such topics include inclusion of additional DER such as food waste co-digestion, outfall electricity generation and/or offshore wind and additional PV on neighboring buildings in the area. Such additional DER suggest the possibility creating a community microgrid. This work will necessarily include further investigation of incentives, especially as emerging for large ESS, and optimization of resource coordination and dispatch.

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# 9. Appendices

## 9.1. *Appendix A – Peak Demand Statistical Analysis*

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.968212456 |
| R Square | 0.937435359 |
| Adjusted R Square | 0.865932913 |
| Standard Error | 97.97999655 |
| Observations | 31 |

| *Red Hook system data (3/2018)* | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 2934.931332 | 3306.713814 | 0.887567385 | 0.389767293 | -4157.264438 | 10027.1271 | -4157.264438 | 10027.1271 |
| Sewage Treated Max (MGD) | 12.14007361 | 3.212104196 | 3.779476899 | 0.002031511 | 5.250795286 | 19.02935193 | 5.250795286 | 19.0293519 |
| Flow totalization (Gal/Sq ft/Day) | 0.643480534 | 1.607273025 | 0.400355462 | 0.69493719 | -2.803777254 | 4.090738323 | -2.803777254 | 4.09073832 |
| Aeration | -3.587422645 | 28.24256401 | -0.127021847 | 0.900729462 | -64.16169798 | 56.98685268 | -64.16169798 | 56.9868526 |
| Sewage Flow | -6162.470241 | 1629.657204 | -3.781451846 | 0.0020236 | -9657.737317 | -2667.203165 | -9657.737317 | -2667.20316 |
| Primary Tanks | 1831.236399 | 541.6423042 | 3.380896182 | 0.004479949 | 669.5291949 | 2992.943602 | 669.5291949 | 2992.943602 |
| Aeration Tanks | -782.5971527 | 368.7398253 | -2.122355924 | 0.052128464 | -1573.465421 | 8.271115966 | -1573.465421 | 8.271115966 |
| Final Tanks | 265.7956427 | 130.2463228 | 2.040715139 | 0.060603513 | -13.55493661 | 545.1462219 | -13.55493661 | 545.1462219 |

Figure 11: Linear Regression of Red Hook March 2018 Plant Data

### *9.2. Appendix B – NREL SAM Parametric Model Inputs and Outputs*

#### *9.2.1. B-1 SAM Methodology For Dispatch Strategy Analysis*

For all dispatch models, SAM has an overall methodology for determining the dispatch values. The variables used in the calculation of all dispatch models include:

- $P_{load}$: Power requirements of the load. This is taken from the hourly system load over a year (8760 load data), which is provided by the facility and imported into SAM.

- PPV: Power generated from PV using the system size, module and inverter specifications, and weather data. Additional information can be used to refine the estimates such losses due to shading, and degradation.

- $P_{grid}$: The difference between $P_{load}$ and PPV which SAM computes over a 24-hour time period. The grid power ($P_{grid}$) needed is provided for every 15, 30 or 60 minute interval (based on load and weather data time step interval) each day. This is an estimate of how much power will be needed from the grid after solar power generated is taken into account.

- Target Power: Maximum desired power to purchase from the grid based on either imported data or battery capacity. If the monthly peak demand is higher than the target value, then the target value is re-set to the monthly peak since demand charges are based on the monthly peak.

The SAM-modeled system discharges the battery if the demand is higher than the target power and charges the battery if it is lower than the target power. While the overall methodology is the same for each dispatch strategy the means of calculating Target Power and $P_{grid}$ differ as discussed below.

- Manual Dispatch: custom profiles are set up and scheduled on a month by month, hour by hour schedule throughout the year. This allows the operator to specify detailed characteristics, such as when to allow discharging, how much of the capacity to discharge, and the minimum state-of-charge. In this analysis a window of 4pm to 10pm was used.

- Look Ahead: For each day, SAM looks ahead to the next day's solar resource via the weather data and load data, to then calculate the $P_{grid}$ values.
- Look Behind: The look-behind controller assumes the load and PV production yesterday will correspond to the current 24-hour profile. These values are used to then calculate the $P_{grid}$ values.
- Grid Power Target: This operational mode allows the operator to input the maximum grid power for several different cases. The operator can enter a single target power for the year, one target for each month, or one target for each time-step (15, 30 or 60 minutes) in the year. The look-ahead controller then uses the programmed target power instead of calculating its own.

*9.2.2. B-2 SAM Results From Dispatch Strategy Analysis*

Table 6: ESS sizes and associated outputs for peak demand shaving scenario analysis

| **Month** | **Without ESS** | **Look Ahead** | **Look Behind** | **Manual Discharge** | **Grid Power Target** |
|---|---|---|---|---|---|
| January | 2610.0 | 2188.0 | 2556.5 | 2529.9 | 2349.0 |
| February | 2919.6 | 2724.2 | 2919.7 | 3289.5 | 2845.7 |
| March | 2660.4 | 2599.7 | 2656.9 | 3044.7 | 2653.4 |
| April | 2660.4 | 2509.0 | 2660.5 | 2846.7 | 2595.7 |
| May | 2570.4 | 2341.4 | 2566.9 | 2566.9 | 2313.4 |
| June | 2725.2 | 2310.3 | 2725.3 | 2929.5 | 2452.7 |
| July | 2883.6 | 2811.7 | 2869.5 | 3228.3 | 2668.8 |
| August | 2786.4 | 2564.1 | 2721.7 | 3019.5 | 2507.8 |
| September | 2995.2 | 2824.6 | 2993.0 | 2975.8 | 2912.4 |
| October | 3247.2 | 2954.8 | 3247.3 | 3247.3 | 2922.5 |
| November | 2908.8 | 2739.1 | 3057.3 | 3030.3 | 2839.6 |
| December | 2746.8 | 2649.0 | 2746.9 | 3141.9 | 2665.6 |
| Total | 33714.0 | 31215.8 | 33721.1 | 35850.0 | 31726.4 |
| Average | 2809.5 | 2601.3 | 2810.1 | 2987.5 | 2643.9 |
| Std Dev | 184.1 | 221.4 | 202.0 | 233.9 | 200.7 |
| Maximum | 3247.2 | 2954.8 | 3247.3 | 3289.5 | 2922.5 |
| Minimum | 2570.4 | 2188.0 | 2556.5 | 2529.9 | 2313.4 |

### *9.2.3. B-3 Results of Simple Payback Analysis of Alternative ESS Sizes*

Table 7: ESS sizes and associated outputs for peak demand shaving scenario analysis

| **ESS Size (kWh)** | **ESS Power (KW)** | **Simple Payback (yrs)** | **Total Cost ($)** | **Savings year 1 ($/yr)** | **Estimated Incentive Pymt ($/yr)** | **Payback: Cost and Savings only (yrs)** |
|---|---|---|---|---|---|---|
| 2000 | 500 | 14.189 | 1844680 | 172152 | 62500 | N/A |
| 2400 | 600 | 13.868 | 2007210 | 176804 | 75000 | N/A |
| 2800 | 700 | 13.056 | 2169270 | 192386 | 87500 | 19.8 |
| 3200 | 800 | 12.714 | 2331330 | 200158 | 100000 | 19.16 |
| 3600 | 900 | 12.361 | 2493400 | 209333 | 112500 | 18.5 |
| 4000 | 1000 | 12.215 | 2655920 | 213985 | 125000 | 19.01 |
| 4400 | 1100 | 11.747 | 2817980 | 228781 | 137500 | 18.69 |
| 4800 | 1200 | 11.482 | 2980050 | 238867 | 150000 | 18.22 |
| 5200 | 1300 | 11.314 | 3142570 | 246491 | 162500 | 18.08 |
| 5600 | 1400 | 11.278 | 3304630 | 249685 | 175000 | 18.49 |
| 6000 | 1500 | 11.004 | 3466700 | 262484 | 187500 | 18.61 |
| 6400 | 1600 | 10.828 | 3628760 | 272240 | 200000 | 18.45 |
| 6800 | 1700 | 10.838 | 3791280 | 274312 | 212500 | 18.58 |
| 7200 | 1800 | 10.754 | 3953340 | 280690 | 225000 | 18.92 |
| 7600 | 1900 | 10.74 | 4115410 | 283948 | 237500 | 19.22 |
| 8000 | 2000 | 10.69 | 4277470 | 289053 | 250000 | 19.63 |
| 8400 | 2100 | 10.672 | 4439990 | 292679 | 262500 | 19.82 |
| 8800 | 2200 | 10.723 | 4602060 | 292670 | 275000 | N/A |
| 9200 | 2300 | 10.768 | 4764120 | 292818 | 287500 | N/A |
| 9600 | 2400 | 10.815 | 4926640 | 292808 | 300000 | N/A |
| 10000 | 2500 | 10.86 | 5088710 | 292801 | 312500 | N/A |
| 10400 | 2600 | 10.903 | 5250770 | 292794 | 325000 | N/A |

## 9.3. Appendix C – Incentive Program Details

| Incentive Calculations Variables | | |
|---|---|---|
| **CHP+SS** | SCR | $162,999.50 |
| | CSRP | $73,349.78 |
| | DLRP | $101,874.69 |
| | VDER | $184,756.00 |
| Capacity Committed (kW/ event) | SCRP/DLRP | 815.00 |
| | SCR Summer | 949.58 |
| | SCR Winter | 680.41 |
| S+S | SCR | $84,751.75 |
| | CSRP | $38,138.29 |
| | DLRP | $52,969.84 |
| Capacity Committed (kW/ event) | SCRP/DLRP | 423.76 |
| | SCR Summer | 541.93 |
| | SCR Winter | 305.59 |
| Resilience | Total committed capacity | $0.00 |
| | Spinning reserve revenue | $292,320.00 |
| | VDER | $822,953.00 |
| | Spinning Reserve (MWh) | 84.00 |

Figure 12: Incentive Payment Variables

### 9.3.1. Federal Investment Tax Credit (ITC)

The 2022 Federal ITC value is used when determining the value of the ITC in the case study scenarios. The equation used is below.

$$(System\ Cost\ -\ Financing\ Cost) * ITC\ Rate \tag{4}$$

There are federal investment tax credits available to offset the cost of installing solar, biogas generation and ESS systems. The federal ITC incentive is only available for federal tax paying entities. The federal ITC allows a company or individual to deduct 26% of the cost of installing a solar system and 10% of the cost of a biogas generation system from their federal taxes until the end of 2022. Beginning in 2023 the ITC drops to 22% and after 2023 it drops to a permanent 10% for commercial projects and 0% for residential projects. ESS on a commercial property is eligible for a credit under the ITC as long as the battery is charged by a renewable energy system more than 75% of the time.

*9.3.2. Demand Charge Management*

The WRRF's electricity provider is the Municipality's Power Authority (MPA). They are billed under the special tariff rate which specifically for customers to use in service of production and delivery services for pollution control and sewage treatment plants. The demand charge is $4.80/kW and is based on the monthly max metered demand (kW). The energy rate changes seasonally: $0.04611/kWh (May - October) and $0.04103/kWh (November - April).

The WRRF also pays a delivery charge to the utility which is billed under the Rate II – Time of Day charge. The breakdown of the delivery charges can be seen in the table below.

Table 8: ConEdison Rate II – Time of Day Delivery Charge Summary

| **Time of Year** | **Description and Time of Day** | **Cost ($/kW)** |
|---|---|---|
| Summer Charges (June - September) | Monday through Friday, 8 AM to 6 PM (high/low tension service) | $8.05 |
| | Monday through Friday, 8 AM to 10 PM (high/low tension service) | $23.69 |
| | All hours of all days (low tension service only) | $21.86 |
| Remaining Months (October - May) | Monday through Friday, 8 AM to 10 PM (high/low tension service) | $14.36 |
| | All hours of all days (low tension service only) | $5.14 |

The savings from demand charge reduction is based on lowering the monthly maximum metered demand. From the dispatch model analysis, it is estimated that the monthly maximum demand could decrease on average by 832 kW/month. Thus, providing a savings of $47,963 per year from reduced demand charges.

*9.3.3. Demand Response Programs*

$$ICAP{-}SCRcapacitypayment = SCRSummerCapacity{*}NoofMonths{*}AverageICAPAuctionRate{+}SCRW \tag{5}$$

$$CSRPreservationpayment = SCRPCommittedCapacity{*}NoofMonths{*}Reservationpaymentprice \tag{6}$$

$$DLRPreservationpayment = DLRPCommittedCapacity{*}NoofMonths{*}Tier2Reservationpaymentprice \tag{7}$$

The Independent System Operator (ISO) demand response programs are used to mitigate demand during peak periods. When demand for electricity is above the normal levels (peak periods), due to unplanned events like extreme heat, inclement weather, and transmission outages, reliability-based demand response programs are in place that pay for load reduction [14]. These programs include the reliability-based demand response programs: Installed Capacity - Special Case Resource (ICAP-SCR) program and the Emergency Demand Response Program (EDRP).

Participants can enroll simultaneously in one of the reliability-based programs and one of economic-based programs. The demand response revenue is a significant source of cash flow and is based on a committed amount of load reduction (commitment value). Seasonality is taken into consideration for the ISO SCR.

The utility's demand response programs are used to curtail energy when the utility grid is stressed due to demand for electricity exceeding its supply. These programs are seasonal, occurring from May 1st to September 30th. These

Table 9: Comparison of NYISO demand response programs [25] (incentive and contract programs)

| **Program Name** | **Payment Types** | **Metering** | **Performance Requirements** | **Min Load Reduction Requirements** | **Seasonal** | **Capacity Payment** | **Energy/ Performance Payment** |
|---|---|---|---|---|---|---|---|
| ICAP-SCR (Reliability-based) | Monthly Capacity Payment & Performance Payment | Hourly Interval Meter | Mandatory for NYISO Reliability Event | 100 kW | Summer: (May - Oct) Winter: (Nov - Apr) | Monthly based on ICAP auction | LBMP with a daily guarantee of strike price recovery and guaranteed 4-hour minimum |
| EDRP (Reliability-based) | Performance Payment | Hourly Interval Meter | Voluntary for NYISO Reliability Event | 100 kW | N/A | None | Greater of real-time LBMP or \$500/MWh and guaranteed 4-hour minimum |

programs include: 1) Commercial System Relief (CSRP), 2) Distribution Load Relief Program (DLRP).

| Program Name | Enrollment Option | Payment Types | Notification | Min Load Reduction | Performance Payment per Event | Reservation Payment [13] |
|---|---|---|---|---|---|---|
| CSRP | Reservation payment | Monthly reservation & Performance payment | 21 hours before a Planned Event.[14] | Capacity committed | Planned: $1/ kWh<br>Unplanned: $6/ kWh | $18 kW/mo |
| | Voluntary | Performance payment | | 50 kW | planned: $3/ kWh<br>Unplanned: $10/kWh | None |
| DLRP | Reservation payment | Monthly reservation & Performance payment | 2 hours before a Contingency Event.[15] | Capacity committed | Contingency: $1/ kWh<br>Immediate: $1/ kWh | $25 kW/mo |
| | Voluntary | Performance payment | | 50 kW | Contingency: $3/ kWh<br>Immediate: $3/ kWh | None |

Figure 13: Comparison of Con Edison demand response programs [26]

Customers can participate in both CSRP and DLRP at the same time. However, a customer can only participate in either the voluntary or reservation option of each program, not both.

### *9.3.4. Value of Distributed Energy Resources (VDER)*

The value of distributed energy resources (VDER) was created to compensate energy generated by distributed energy resources. VDER pays projects based on when and where they provide electricity to the grid with payment in the form of bill credits. This is determined by a DER's valuation components as described in Table 9.

### *9.3.5. Spinning Reserve*

The ISO provides incentives for owners of ESS systems who can be called upon for spinning reserves. Spinning reserves are generation capacity that is already operating and synchronized to the utility system and can increase or decrease generation within a specified time period. For example, the ISO has a 10-minute spinning reserve and a 30-minute spinning reserve incentive. Spinning reserve is used by energy providers to mitigate unplanned outages of other

Table 10: VDER valuation components [25] (incentive and contract programs)

| **Program Name** | **Payment Types** | **Metering** | **Performance Requirements** | **Min Load Reduction Requirements** | **Seasonal** | **Capacity Payment** | **Energy/ Performance Payment** |
|---|---|---|---|---|---|---|---|
| ICAP-SCR (Reliability-based) | Monthly Capacity Payment & Performance Payment | Hourly Interval Meter | Mandatory for NYISO Reliability Event | 100 kW | Summer: (May - Oct) Winter: (Nov - Apr) | Monthly based on ICAP auction | LBMP with a daily guarantee of strike price recovery and guaranteed 4-hour minimum |
| EDRP (Reliability-based) | Performance Payment | Hourly Interval Meter | Voluntary for NYISO Reliability Event | 100 kW | N/A | None | Greater of real-time LBMP or $500/MWh and guaranteed 4-hour minimum |

resources. These reserves are used to respond to events quickly while other resources are being brought online. When dispatched, the ESS must be capable of sustaining its awarded capacity for the designated amount of time. the ISO provides payments based on location for capacity reserved. Reserve providers must bid in day-ahead market in order to determine current spinning reserve price for their location. The NYISO 10 minute spinning reserve payment ranges between \$2.88 and 7.71\$/MWh.

*9.3.6. Non-wire Solutions (NWS)*

The non-wire solutions incentive provides the utility with exclusive dispatch rights to the designated battery for a specified period of time depending on the RFP being answered. This is usually during summer months, May to September. During this time, the ESS is not available for use for other incentive programs or company objectives such as peak demand shaving or resilience. In addition, if there is any interference with the utility's ability to fully dispatch the ESS unit during the contracted time, the ESS owner will not be able to participate in future the utility's incentive programs. This incentive program is not feasible for the WRRF under the proposed operating scenario as the ESS would not be available for use for peak demand shaving or resilience.