NC STATE UNIVERSITY

Community Solar for the Southeast

Municipal Utility Case Study
Fayetteville Public Works Commission

SunShot U.S. Department of Energy

PWC Fayetteville's Hometown Utility

NC Clean Energy Technology Center

Executive Summary

The North Carolina Clean Energy Technology Center (NCCETC) at NC State University was tasked with providing a Community Solar Project concept for consideration of the Fayetteville Public Works Commission (PWC). This case study and the tasks associated with it, are intended to provide a detailed analysis incorporating the economic viability of a community solar project for the city. The case includes three parts i) system selection, ii) battery dispatch optimization, and iii) community solar program guidance.

This abridged version of the report is provided as deliverable for the U.S. Department of Energy funded Community Solar for the Southeast project. This document provides a real-time analysis that may guide cooperatives and municipalities that are seeking a guide for community solar initiatives. Please contact NCCETC for additional details on the model.

Fayetteville PWC provides electric service to more than 87,000 customers in the Fayetteville/Cumberland County area of North Carolina. PWC is the largest Public Power provider in the state and the 35th largest in the United States. PWC has been recognized by the American Public Power Association for outstanding electric system reliability as four-time recipients of the RP3 (Reliable Public Power Provider) Diamond Designation and as winners of the APPA's E.F. Scattergood System Achievement Award for sustained achievement and customer service.

The initial request was to conceptualize a 500 kW of solar PV and 200 kW of battery storage community solar project. The solar plus storage project included the following objectives:

1. Helping meet the compliance for the state's Renewable Energy Portfolio Standard
2. Addressing customer demand for solar options
3. Balancing sustainability with effective economics for PWC and its customers

The outcomes of the technical and program design assistance for the Community Solar Project covered in this report included the following categories:

System Selection and Cost / Benefit Analysis

The team built an hourly production and economic model incorporating monthly coincident peaks, PWC energy and demand rates, PV costs, and battery storage costs with adjustable power and energy capacity, utilizing controls. Additionally, PV system orientation options, including 1-axis tracking, was reviewed.

This analysis includes a proposed project budget and the design of the community solar program, using a computer model to assess expected design and operation of the system with adequate accuracy. It includes three models- i) incorporating user-adjustable variables for inputs and economics, based on ii) integrated hourly, project lifetime model, and iii) community program solar models.

The cost / benefit analysis outlines PV system output, battery energy storage including control algorithm and a value calculation. It also includes expected demand reduction based on battery usage as well as PV system generation.

Synopsis of findings: It was quickly determined that it would be in the utilities' and customer's best interest to increase the capacity of the battery storage from 200kW to something larger. Five hundred kilowatts of battery storage was found to be an optimum capacity. Based on better than expected economics at 500kW of PV, it was decided to double the PV capacity to 1MW, which is a more common and is more cost effective per kW. The total cost of the 1.2 MW_{DC} solar PV system and 500 kW_{DC}/1 MWh_{DC} battery storage system is expected to be approximately $2.55 million, but could fall within the range of $2.13 million to $2.96 million. If PWC were to simply own the system and accrue the financial savings itself, rather than implementing a community solar program, PWC would break even in about 12.5 years and achieve a net present value of $1.2 million. Incorporating a community solar program designed for PWC to break even over the life of the system would extend the payback time to about 17 years and provide PWC with a net present value of $0.

Battery Operation Procedure for Dispatchability at Monthly Peak

In order to accurately estimate the benefits of the demand reduction provided by the battery, the team developed a battery control algorithm that may be used to control the operation of the battery once it is installed. Development of this real-time control system required methods to predict the time of occurrence of the monthly peak based on data available at the start of each hour. The operation procedure was developed and tested using nine years of Duke Energy Progress (DEP) hourly demand data and corresponding ambient temperature and solar radiation data.

Synopsis of findings:

When tested using weather and Duke demand data from 2006 to 2015, the battery operation procedure is able to successfully discharge a battery with a 2-hour storage capacity during the monthly peak hour in about 95% of months. This battery operation procedure represents what the team believes is a reasonable estimate of the ability for the proposed battery system to reduce PWC's demand at the time of Duke Energy Progress's monthly coincident peak demand. The installed system may use a control system from the battery product vendors, control by PWC or ElectriCities, the algorithm presented in this report, or some combination of these options.

Community Solar Program Design Guidance

A number of community solar program models and lengths of participation were compared and contrasted for this task, based on the needs of PWC and its customer base. Elements such as REC (renewable energy certificate) treatment, customer eligibility including minimum terms, deposits, transferability, financing, and tax considerations were included in the analysis of a suitable program for customers.

Synopsis of findings: The 1.2 MW_{DC} system would contain a total of about 3,700 solar panels, each available as a "share" of the project (along with an accompanying percentage the battery system). The monthly cost for community solar subscribers is set to provide a $0 net present value to PWC, which results in a $4.13 per share per month subscription fee (assuming our nominal system price estimate), with this fee amount remaining the same throughout the program. Each month subscribers receive a bill credit equal to the value provided by the PV and battery system minus any operating costs. *Notably, the model projects subscribers will see a net financial benefit in the very first year of the program, and this net benefit will only increase over time, driven by expected* DEP *rate increases.* As proposed, the expected rate of return for PWC is 4.0%, their discount rate, over a 25-year project life.

About the Community Solar for the Southeast project

The Community Solar for the Southeast project aims to make solar more affordable and accessible through shared solar projects developed by cooperatives and municipal utilities across the southeast. The project aims to lead stakeholder process with rural public power utilities to determine solutions needed to increase development of community solar project. The team will provide technical assistance to analyze, design, and implement community solar projects.

The project is led by the North Carolina Clean Energy Technology Center with partners including Rocky Mountain Institute, Fayetteville Public Works Commission, NC Justice Center, National Rural Electric Cooperative Association, Roanoke Electric, Strata Solar, EcoPlexus, Geenex, and GreenLink. The project is funded by the Department of Energy SunShot program under Solar Energy Evolution and Diffusion Studies-2-State Energy Strategies (SEED2-SES).

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About the North Carolina Clean Energy Technology Center

The NC Clean Energy Technology Center is a UNC System-chartered Public Service Center administered by the College of Engineering at North Carolina State University. Its mission is to advance a sustainable energy economy by educating, demonstrating and providing support for clean energy technologies, practices, and policies. The Center provides service to the businesses and citizens of North Carolina and beyond relating to the development and adoption of clean energy technologies. Through its programs and activities, the Center envisions and seeks to promote the development and use clean energy in ways that stimulate a sustainable economy while reducing dependence on foreign sources of energy and mitigating the environmental impacts of fossil fuel use.

Acknowledgements

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Disclaimer

Contents

1 Overview of Cost / Benefit analysis

The purpose of the cost / benefit analysis was ultimately to have adequate understanding of the project economics to inform a decision on if and how to proceed with development of a community solar project. The analysis results also guide the development of the project budget, the procurement process, and the design of the community solar program. The foundation of the cost / benefit analysis is a detailed computer model of the economics of the proposed solar + storage community solar project. We built this model in Excel to reflect the expected design and operation of the system with adequate accuracy. The full model consists of the following three model layers, contained across several worksheets in a single Excel workbook.

Hourly Model - The lowest-level model is an hourly production and control model that uses nine years (2006 through 2014) of historic hourly weather and Duke Energy Progress coincident demand data. This model is able to calculate the output of the solar PV system based on the selected PV system attributes (PV capacity, mounting option (i.e. fixed, 1-axis tracking)). Included in this hourly model are real-time controls that determine when the battery system is charging and discharging based on a control algorithm designed to maximize energy output during the hour of Duke's coincident peak each calendar month.

Project Lifetime Model – The next model layer takes the monthly average results from the 9-year hourly model as the performance of the first year of the project. The model then applies various project economic and time factors to model project economics for the expected life of the system. This model considers direct ownership of the project by PWC, but does not consider a community solar program.

Community Solar Program Model – The highest-level model adds a community solar program to the basic project lifetime model. This model follows the cash flows between PWC and community solar participants. Several possible community solar program options were modeled for comparison. PWC and Participant points of view are each modeled.

2 PV + Storage Hourly Model

This model is the foundation of the highest-level lifetime and community solar models. It does not include many economic factors, primarily energy and power factors, however all of the economic calculations are based on the results of the hourly model. The primary output of this model is the energy production from the solar PV, the demand reduction due to solar production, and the demand reduction due to the battery system. The model also tracks energy used for battery recharging. The system characteristics used in the hourly model are defined in the Inputs and Economics tab in the spreadsheet.

2.1 Hourly Model Data Inputs

Several hourly datasets were used. In each, we carefully treated each to align all data to the model time steps. In our model, the time of each row is the time at the start of the hour and the data in that row represents the data that hour. All times are in Eastern Standard Time (no Daylights Saving Time).

2.1.1 Solar Radiation and Ambient Temperature in Fayetteville Area

Solar radiation data for Fayetteville was not available for the required period, however the NC Climate Office was able to provide hourly solar radiation and ambient temperature data for the nearby towns of Clinton, Goldsboro, and Whiteville for the entire modeled period. Each of these datasets were found to have some missing and erroneous data, so we processed each to remove any erroneous data and ignore missing data, before averaging the remaining data for each hour of this nine-year period.

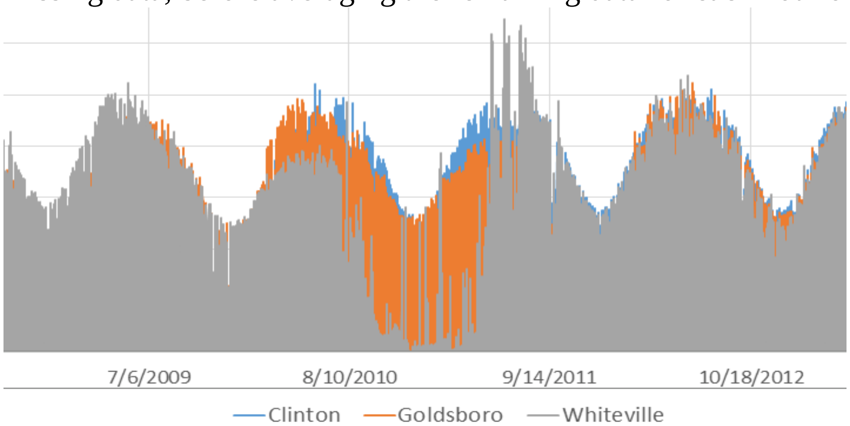


Figure 1: Sample of raw solar radiation data before removing bad data

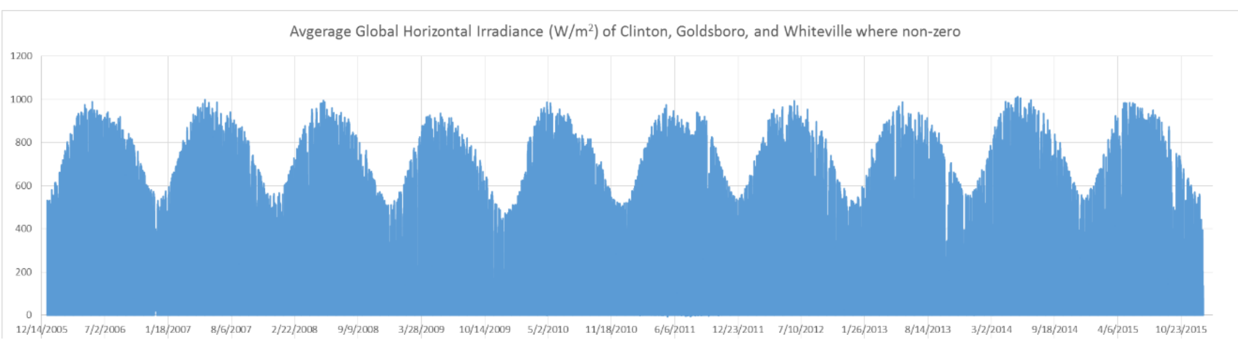


Figure 2: Graph of 9-years of solar radiation data (after processing of raw data) used to calculate solar PV output

2.1.2 Ambient Temperature in Duke Energy Progress Territory

The Duke Energy Progress coincident demand is closely related to the ambient temperature in the territory it serves, so data to reflect the average ambient temperature of the territory is central to the algorithm that controls the operation of the battery. Hourly ambient temperature data provided by the NC Climate Office for Raleigh, Salisbury, Jackson Springs, and Siler City were averaged to create a proxy for the average ambient temperature of the Duke Energy Progress territory. These cities were chosen based on an initial, incorrect understanding that PWC's demand charge was based on the full Duke Energy (DEP + DEC) demand rather than just Duke Energy Progress. A marginal improvement to the performance of the battery control system is likely if a mixture of weather data more related to DEP demand were used. The error was discovered after the model had shown very good performance, so our team and PWC agreed that the effort required to update the weather data was not justified at this time.

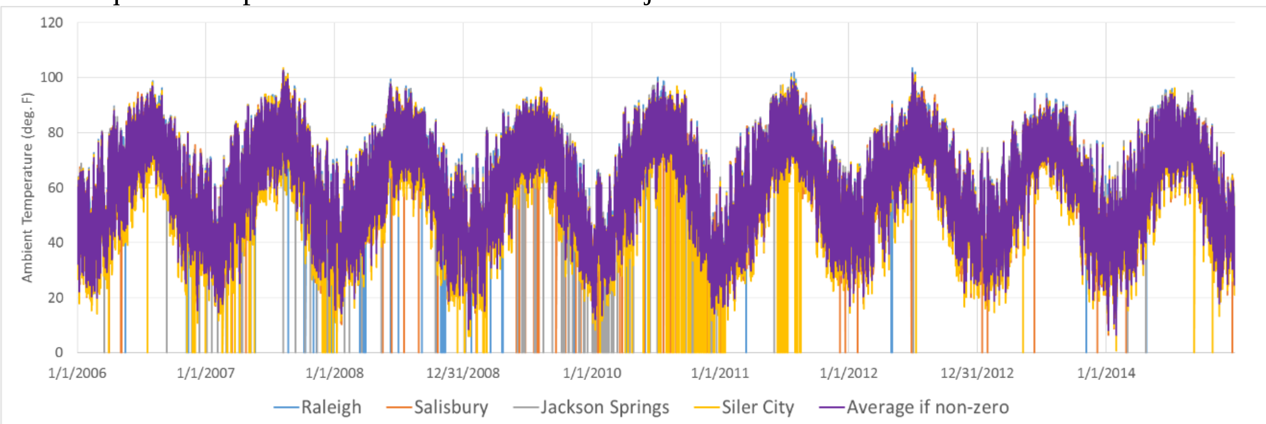


Figure 3: Ambient Temperature data for model, showing raw un-corrected values for four cities as well as the corrected average temperature used in the model (shown in purple)

Duke Energy Progress Hourly Coincident Demand – The raw demand data came from the Federal Energy Regulatory Commission's (FERC).

Figure 4: Duke Energy Progress Hourly Average Coincident Demand 2006 through 2014

2.2 PV Output

The custom PV model based on the nine years of local weather data was used to define the shape and timing of the PV output each day, and the absolute magnitude of the PV production is defined by PV

Watts which uses longer-term weather data (30-year TMY2 data) and a more refined and proven PV performance model. Additional validation of the PV production model is provided by the SAM model validation in a later section of this report.

For file and computational efficiency, this PV production model was built in a separate spreadsheet from the main model. The model was run for three different PV panel mounting options. The hourly results for each option were copied and pasted into the main hourly model. The three mounting options analyzed were:

- **Fixed 20-degree tilt, south-facing:**
  - This is the most common structure for NC solar farms
- **1-axis tracker:**
  - Each row of panels slowly rotates to follow the sun's path across the sky
  - At solar-noon each day the solar panels are perfectly horizontal, in the morning they are facing east toward the rising sun, in the afternoon they are facing west toward the setting sun. This is the next-most common structure for NC solar farms.
  - Maximum of 45-degree tilt east or west. This is conservative simplification of typical tracker products on the market, which rotate up to 60 degrees but will rotate less when needed to prevent inter-row shading. Depending on the construction density of rows of trackers, this simplification results in a small to negligible underestimate of PV production near the start and end of the day.
- **Fixed 30-degree tilt, 65 degrees West of South-facing:**
  - This arrangement is the result of an optimization analysis we conducted to find the tilt and orientation that maximizes the value of PV production (combination of energy and demand reduction) based on PV output alignment with DEP peaks and the rates PWC pay for demand and energy.

A comparison of the output for each mounting option is included in the Cost / Benefits Analysis section of this report. Below are graphs of the energy production and the demand charge reduction provided by the best performing mounting option, a 1-axis tracker.

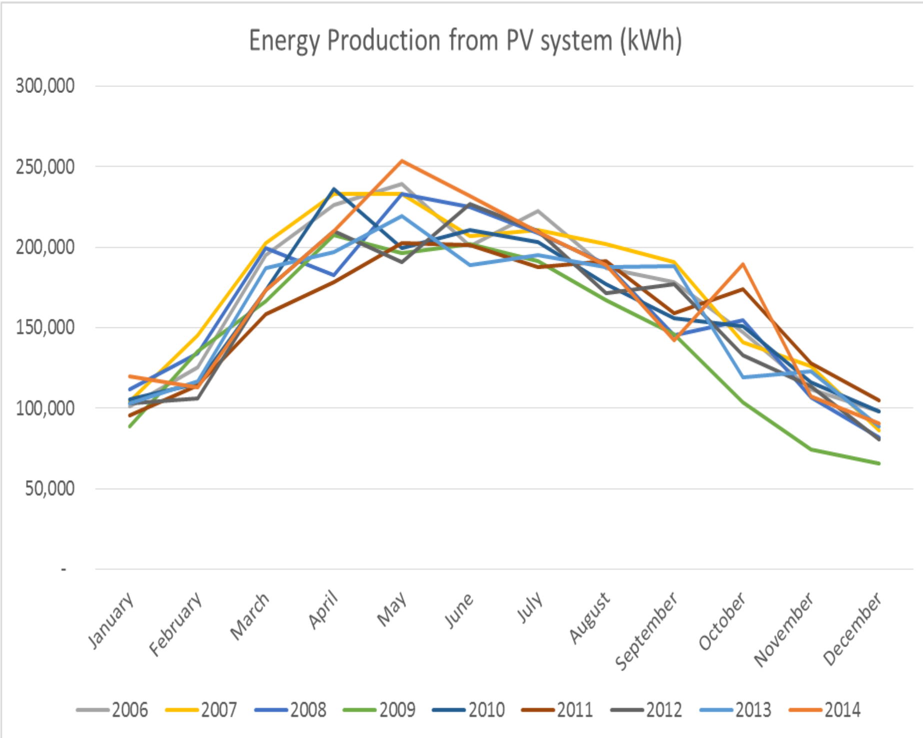


Figure 5: Monthly Energy Production for all years of hourly model, 1,200 kW_DC 1-axis tracked array

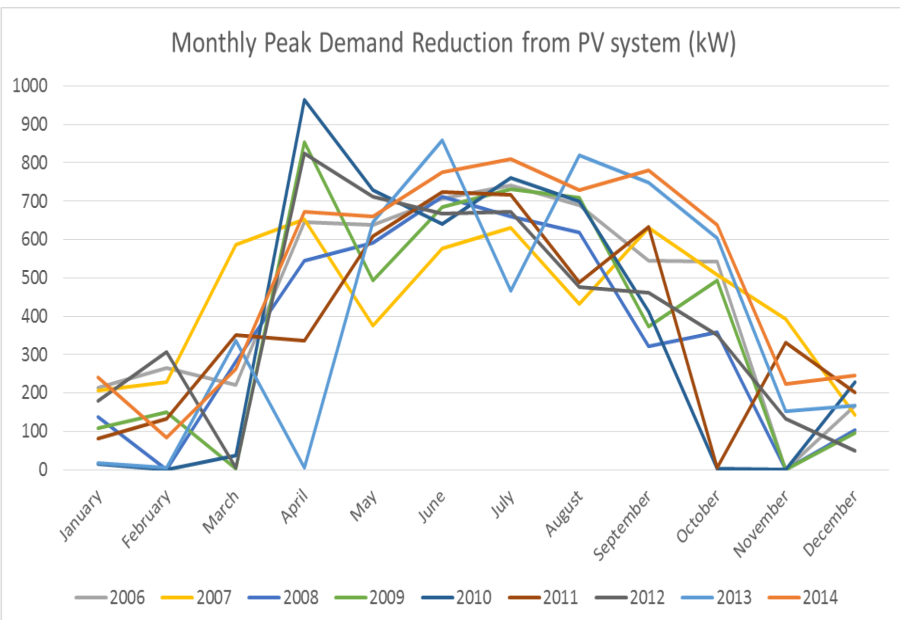


Figure 6: Monthly Demand Reduction at Coincident Peak for all years of hourly model, 1,200 kWDC 1-axis tracked array

2.3 Battery Energy Storage Operation

Grid-tied utility-scale batteries are capable of providing many different services, but in this model, we are only using the battery with the goal of reducing the demand charge PWC is charged monthly by Duke Energy, reducing PWC's average load during the hour of Duke Energy Progress's coincident demand peak. Demand reduction is a significant value and relatively straightforward to model. During the development of this model PWC did not feel they had any grid challenges that could be meaningfully addressed with a battery. In order to realistically model the performance of the battery energy storage system, the timing of its charging, and discharging, as they will occur in the real world must be included in the model. The control algorithm created could be used to control, or help control, the battery in the installed system, but this is not the primary goal of its development. The end goal of the battery control model is to provide confidence in the amount of monetary value that it can be reasonably expected to provide.

The team chose to define the battery power capacity in DC kW and the battery energy capacity in DC kWh, which means that the AC power and energy delivered to the grid is less than the DC power and energy capacity of the battery due to inefficiencies in the battery system. If a battery system with power and/or energy capacities defined in AC kW and AC kWh is to be modeled, these values will need to be converted to DC to be properly modeled in the current model.

2.3.1 <u>Battery Charging</u>

All charging modes use the same maximum battery charging rate, which is an input variable in the Inputs and Economics tab of the model that is defaulted to a 0.50 C rate. The model considers the AC to DC conversion efficiency of the battery system, so at the default efficiency of 93.5% it requires 535 kWh_{AC} to recharge the battery with 500 kWh_{DC} of energy. The net energy lost due to inefficiencies of charging and discharging the battery are summed and treated as a system cost based on PWC's cost of energy.
The model can be operated in any one of 3 different battery-charging modes. The default operation is Charging from Grid and Solar, which is designed, but not yet very well optimized, to generally reply on solar output to charge the battery but will alternatively charge from the grid when the battery control system thinks that there is a chance that it might want to discharge the battery before it has a chance to be fully charged from solar. Operation in either Grid Only or Solar Only can be used to demonstrate the impact on value production by the system by a given mode of charging.

- Charging from the Grid Only
    - charges at the maximum charging capacity of the battery until the battery is full in any hour that the control system does not call for a discharge
- Charging from Grid and Solar
    - Results in about 87% of charging energy coming directly from solar output.
    - Charges directly from solar production when the battery is not full and there is solar production.
    - The controls of this charging mode could be made much more sophisticated, but adequate

performance is provided with this simple control so development was halted.

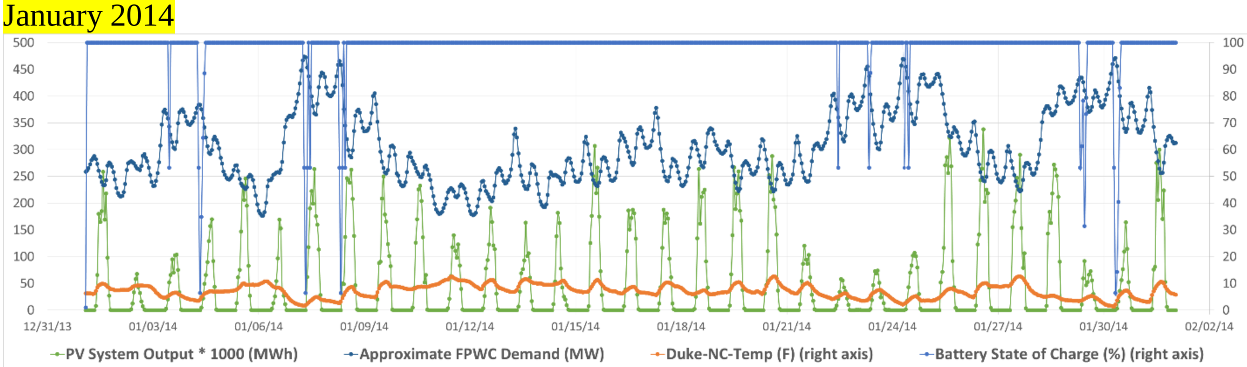
    - This control can very occasionally result in charging the battery during a monthly peak. The control could be improved to avoid this situation.
    - This control easily achieves over 75% of charging energy coming from PV, but this could be increased with control improvement.

- Charging from Solar Only
    - Charges the batteries using the current solar production, up to the maximum rate of battery charging, until the battery is fully charged.

2.3.2 Battery System Performance

The graphs below demonstrate the nature of the Duke demand, its relationship to ambient temperature, and the charging and discharging of the battery as controlled by the algorithm described above. The characteristics of the demand curve and its relationship to temperature changes dramatically between different seasons, as demonstrated with several example months from the different seasons during the most recent year modeled, 2014. The dark blue line (left axis) is an approximation of the PWC hourly demand, which is simply the Duke Energy Progress hourly demand divided by a factor of 30. The green curve (left axis) is the PV output magnified by 1000 (i.e. the left axis reads in kWh). The orange (left axis, not right axis as indicated in the key on each graph) is the ambient temperature data for Duke's territory as described in the hourly model, in Fahrenheit. The lighter blue (right axis) is the battery state of charge, where 100 is 100% charged and 0 is fully discharged.

January 2014



2.4 Value Calculations

The calculation of the value created by the solar and battery systems is simplified due to PWC's straightforward supply contract rate with Duke Energy. PWC purchases energy throughout the year at a flat rate. Additionally, PWC pays a demand charge, including transmission charges, based on their average power demand during Duke's monthly coincident hour-long demand peak. Both the PV system and the battery system are able to provide a valuable demand reduction. Once the model has estimated the hourly PV production and the hourly battery operation it is simple to calculate the monetary value to PWC in savings on its monthly bill from Duke Energy.

The true value of the reduction comes from discharging the system at coincident peak. Each municipal or cooperative would need to review their supply contract for an accurate accounting of value and savings.

Finally, there is value to PWC in the Renewable Energy Certificates (RECs) generated by the system. Currently, PWC Is purchasing RECs from third parties in order to meet their requirements in the N.C. Renewable Portfolio Standard. PWC valued the generation of a REC (1,000 kWh) to be a nominal amount which is included in the modeled value of each kWh generated by the PV system.

In addition to these value streams, there is the potential for additional value streams to be provided, especially from the battery storage system. For example, there are some situations where PV or batteries can allow a utility to defer a needed upgrade by limiting congestion on a line, which saves the utility money.

It can be seen in the graphs below that the two largest value streams are the demand reduction by PV production and the demand reduction from strategic operation of the battery energy storage. The third primary value stream is the actual energy generated by the PV system. The RECs are worth much less than these three primary value streams. Notably, the cost of the energy lost due to the inefficiency of the battery energy storage is negligible compared to the other value streams.

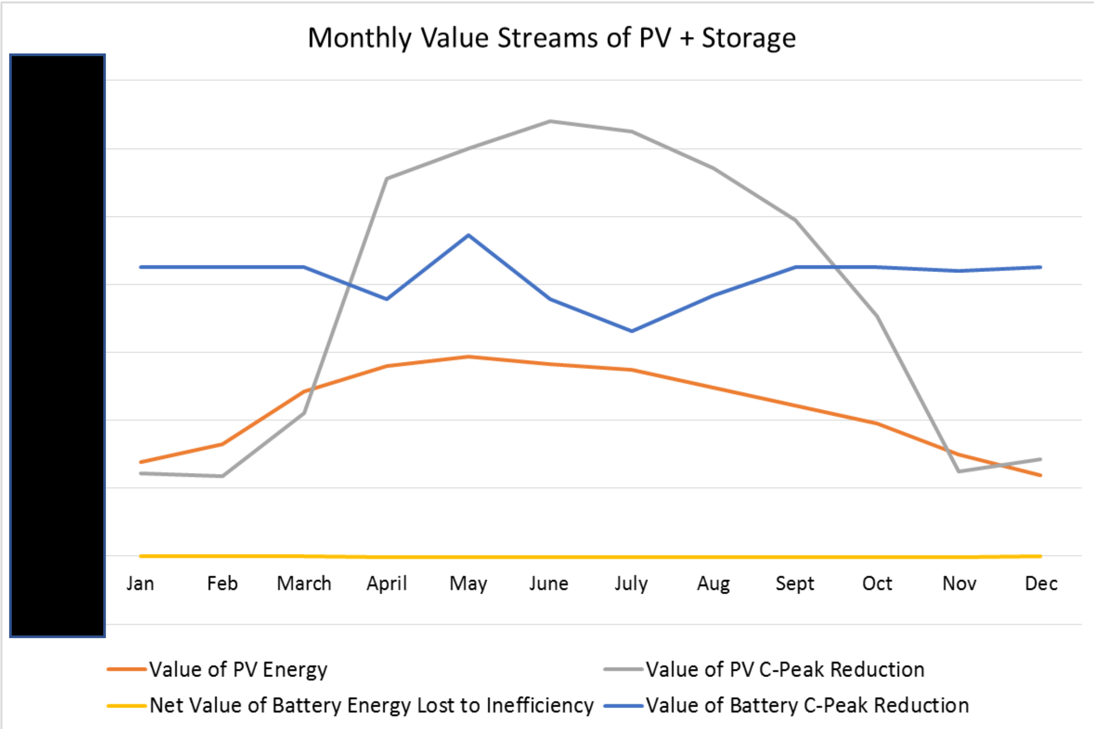


Figure 14: Monthly Value Streams (average of 9 years of data) provided by PV and Battery systems

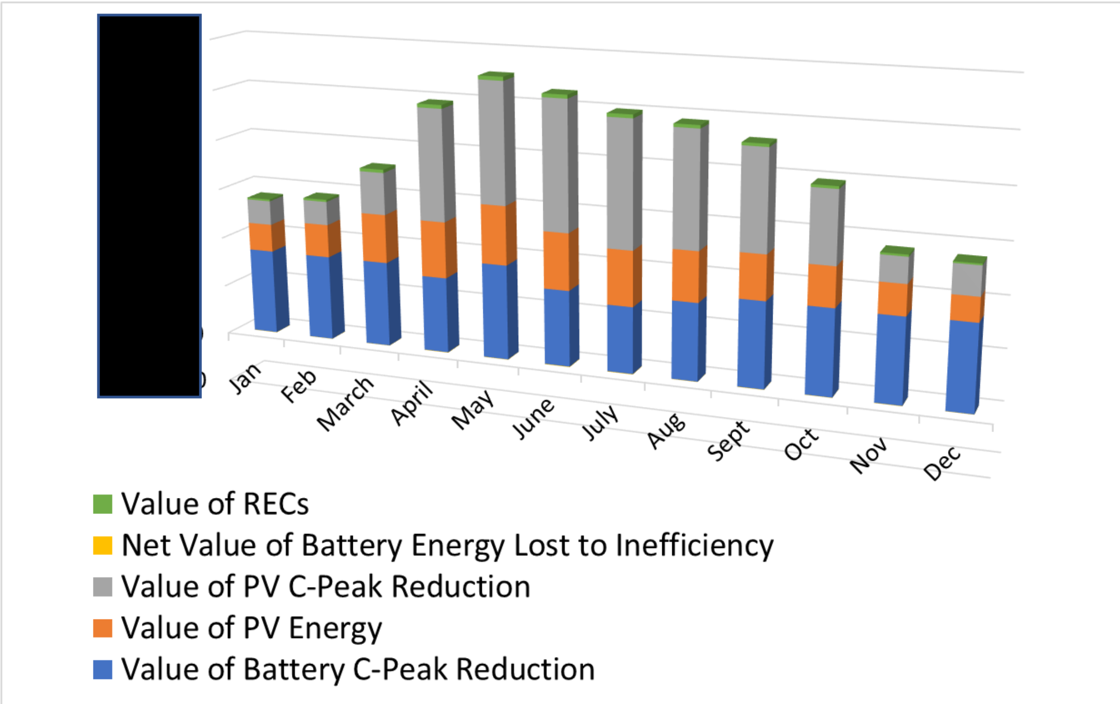


Figure 15: An alternative representation of Monthly Value Streams (average of 9 years of data) provided by PV and Battery systems

3 Lifetime Model

The results of the hourly model are averaged over its nine-year span to find the average/typical year's performance. This average year's performance then served at the first year in the lifetime model of the system. The focus of the lifetime model is economics, which includes accounting for changes over time in PV module performance and battery energy storage capacity, as well as the initial capital costs for the system. The model assumes PWC owns the system directly and pays for the system with cash (4.0% discount rate used to calculate NPV, but no financing costs considered). The solar and storage aspects of the project costs are separated as well as feasible, with all of the system-wide costs attributed to the PV system. Operation as a community solar project is not part of the lifetime model, rather operation as a community solar project is applied on top of the lifetime model of the project itself.

3.1 Summary of Initial System Capital Costs

System Costs	Nominal	Low	High
FPWC development costs	$ 75,000	$ 40,000	$ 100,000
EPC Cost per $/W_DC (non-tracking)	$ 1.30	$ 1.20	$ 1.40
Tracking cost adder per $/W_DC	$ 0.15	$ 0.10	$ 0.25
Interconnection costs	$ 110,000	$ 50,000	$ 150,000
Cost of Turnkey PV System ($)	$ 1,925,000	$ 1,650,000	$ 2,230,000
Total Installed Cost of Battery System ($)	$ 625,000	$ 475,000	$ 725,000
Total Battery System cost per kW	$ 1,250	$ 950	$ 1,450
Total Battery System cost per kWh	$ 625	$ 475	$ 725
Total Cost of PV + Battery ($)	$ 2,550,000	$ 2,125,000	$ 2,955,000
Typical Annual Savings from Duke of PV + Battery ($)	[redacted]		
RECs value (savings)			
Total annual value to FPWC of PV + Battery ($)			
w/o comm. solar, Simple Payback (years)	10.5	8.7	12.1

Figure 17: Summary of Initial Costs for PV and Battery System

3.2 PV System Costs including O&M

The all-in cost for the PV portion of the considered project consists of work that can be organized into the following categories:

- <u>Development:</u> site selection, surveys, site plan design, title work, wetland delineations, permitting, interconnection agreement, environmental studies, legal work etc.

- Interconnection: cost to utility for utility expenses to provide any needed upgrades and to construct the point of interconnection
- EPC: Engineering, Procurement, and Construction of the PV system, includes commissioning, documentation, and monitoring system

We consider the PV system the core of the project and believe most of the development and interconnection costs will be very similar with or without the storage aspect of the project, so we have assigned all of the development and interconnection costs to the PV component of the system costs.

These various components of the work to create an operating project can be completed by two or more entities or by a single entity. Regardless of who completes the work, costs can naturally be organized into the three categories shown above. The total of all three costs in the often called the "all-in" cost for the project. The Center reviewed national and regional reports and interviewed several of the most-experienced solar developers and EPC firms in the North Carolina solar market to arrive at the following cost estimates for a project to be bid in 2017 and built in late 2017 or in 2018.

Below is the breakdown of total capital costs provided in the NREL Cost Benchmarks Report. In this structure, the interconnection costs are under the development cost category.

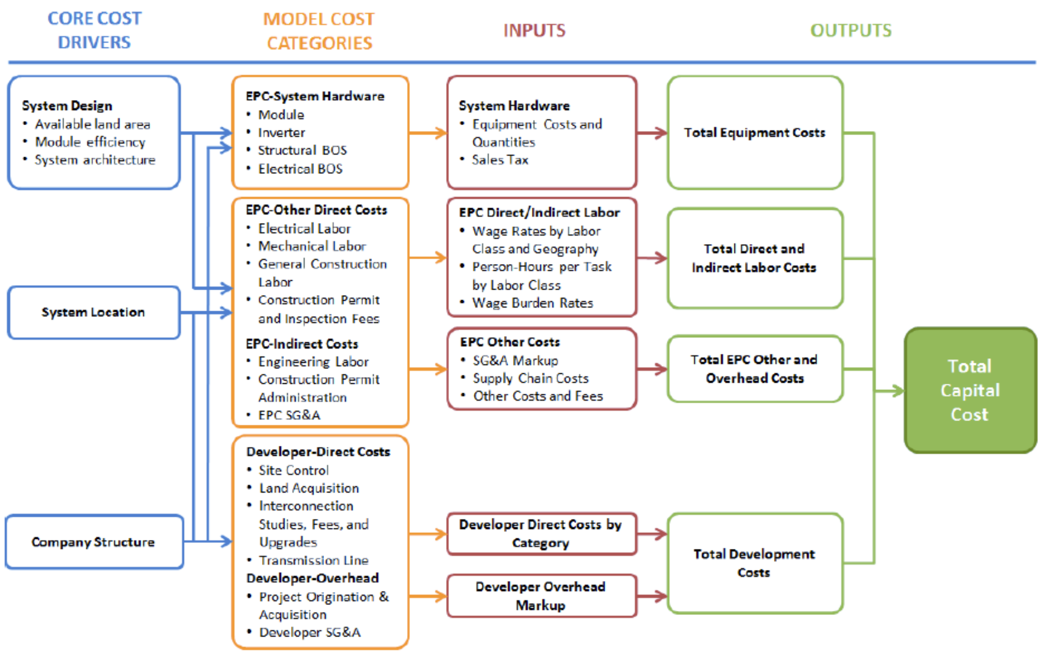


Figure 18: Source NREL Cost Benchmarks Report: Utility-scale PV cost model structure

Our cost estimates are broken down into three different levels: Nominal, Low, and High. Nominal represents our best estimate for a 0.5 to 1.0 MW_{AC} system, on a per MW_{DC} basis. The low prices represent the low end of the range of what we think could be achieved for the same system and the high prices represent the high end of the range of possible costs for this system, which represents a case where market prices increase or there are significant unexpected complications. The low price will be easiest to achieve if the EPC contract for this project is part of a portfolio of other similar projects.

Table 4: Current Cost Estimates for a 1-MW_{AC} PV System at PWC (1 MW_{AC} system with a 1.20 MW_{DC} PV array)

System Costs	Nominal Price	Low Price	High Price
PWC development costs	$ 75,000	$ 40,000	$ 100,000
EPC Cost per $/W_DC (non-tracking)	$ 1.30	$ 1.20	$ 1.40
Tracking cost adder per $/W_DC	$ 0.15	$ 0.10	$ 0.25
Interconnection costs	$ 110,000	$ 50,000	$ 150,000
Cost of Turnkey Tracked PV System ($) (1$MW_{AC}$)	$ 1,925,000	$ 1,650,000	$ 2,230,000

3.2.1 Development Costs

Most ground-mounted solar facilities have the initial solar development completed by a solar developer, who may or may not also be the EPC firm, or partnered with the EPC firm, but these systems are generally being sited on leased land. In the situation where the land or building owner is initiating the project, the land/building owner generally performs as least some of the development work (finding/securing site, securing permits, wetlands assessments, etc.) and might perform the majority of it. If a private solar developer or similar entity were hired to complete these development activities, we expect the cost to be $25,000 to $100,000. Below is a quote from email from an out-of-state solar developer that is very experienced with solar development in North Carolina, mostly in 5 MW_{AC} projects (6 – 7 MW_{DC}) in response to our friendly request for guidance on development cost for a 0.5 to 1.0 MW project.

> *"…the development costs for a project of that size -- including title work, surveys, wetland delineations, Phase I, regulatory/legal expenses -- should not exceed $50k, presuming relatively standard greenfield sites that don't require any kind of environmental remediation or complicated wetland permitting. I've not worked on a site quite that small in NC, but I'd guess that such work could be completed for close to half that, using local, lower cost firms. And I have trouble imagining a scenario where those costs get anywhere close to $100k for a project of that size."*

This is in line with other guidance from the local PV industry that development costs on the much more common 5 MW_{AC} projects are on the order of $50,000 to $200,000 per project depending on who is doing the work and the complexity of each project. Clearly, there are some economies of scale to be gained by developing projects larger than 0.5 to 1.0 MW projects. In fact, the development costs are not expected to materially change when going from a 0.5 MW to a 1.0 MW project.

3.2.2 Interconnection costs

These cost estimates were developed by the NCCETC based on literature and input from local solar industry. These values were presented to PWC engineers and were accepted as reasonable estimates for the interconnection cost if the system is sited at PWC's generation plant and connected at 12.5 kV.

3.2.3 EPC Costs

Note that recent drop in module prices from \$0.50-\$0.65/W to \$0.35-\$.45/W represents at least \$0.15/W decline between Q2 and Q4 of 2016.

Conversations with five EPC firms that mostly build 5MW and larger PV projects, many in NC:

- Large Southeast Solar Developer (1): "On EPC costs, those numbers [referring to Table 4] are probably slightly high. Of course, if you could aggregate to a 5 MW RFP the EPC cost could be below \$1.10 [/W_{DC}]."
- Large Southeast Solar Developer (2): "Our team has reviewed these numbers [referring to Table 4] and they are very reasonable for a company that is scaled to perform this type of work. If a company is scaled to do more utility-scale work (20+MW) then the costs might be \$0.15-0.20 more per watt for projects this small."
- Large national developer/EPC with lots of NC experience:
    - would not be crazy to talk about \$1/W_{DC} on 50+ MW projects in the southeast
    - joining a portfolio is definitely helpful but have a hard time putting values to it, maybe a 5% savings from 500kW or 1MW to a 5 MW portfolio, and a 10% savings from a 1 MW to a 20 MW portfolio.
- Large national PV EPC (summer 2016):
    - Expects about \$1.20/W_{DC} for tracked 50+MW projects
    - \$1.30/ W_{DC} for 5 MW tracked
    - Maybe \$1.40 for 0.5 to 1.0MW tracked
- Moderate-sized leading NC-based PV developer
    - Shared his actual costs for a similar 1 MW_{DC} tracker in Tennessee
        - Built by a large east-coast solar EPC
        - EPC selected through competitive bid
        - Project paid \$0.53/W for PV modules
        - EPC total, including one change order, was \$1.65/W_{DC}
        - Updating this project cost into an estimate for a similar project at PWC:
            - EPC with modules at \$0.40/W: \$1.65/W_{DC} – \$0.13/W_{DC} = \$1.52/W_{DC}
            - overall 10% reduction due to system price drops over 1-year: \$1.52/W = \$0.152/W_{DC} = \$1.37/W_{DC}
            - results in an EPC estimate for this project of \$1.37/W_{DC}, for a tracked array
        - Interconnection charge from Co-op was \$100,000, or \$0.10/W_{DC}, which is similar to our interconnection estimate
        - Development charges, including environmental, real estate, insurance, title, and closing, but not including interconnection charge were \$85,287, or \$0.085/W_{DC}, which is similar to our development cost estimate

Other data points that support our price estimates:

- EPB, a small utility in Chattanooga TN, had a competitive RFP for 1.35 MW community solar farm EPC and got 8 bids, lowest and winning bid selected in Sept 2016 was $1.28 per Watt [assume this is WattDC].[1]

- NREL U.S. Solar Photovoltaic System Cost Benchmark Q1 2016 (Published September of 2016):[2]
  - Modeled EPC costs for a 100 MW system with $0.64/W modules is $1.14 for fixed tilt and $1.19 for tracking, or less than $1/W with $0.40/W modules.
  - EPC-only for 5MW is about $1.40/W (fixed) to $1.50/W (tracked) with $0.64/W modules, or $1.15 (fixed) to $1.25 (tracked) with $0.40/W modules.
    - With interconnection, developer costs, and profits: $1.92/W for 5MW tracked and $1.82 for fixed tilt (with $0.64/W modules)
      - Developer overhead in this NREL model is $0.20/W for a 5MW project, or $1,000,000 which is ten times higher than NC sources have provided for a 1 MW projects (includes: "overhead expenses such as payroll, facilities, travel, legal fees, administrative, business development, finance, and other corporate functions")
- GTM US Market Insight[3] Year-in-Review 2016 bottom-up modeling found Utility fixed-tilt and tracking projects in Q4 2016 saw average pricing of $1.06/W_{dc}$ and $1.18/W_{dc}$, respectively. Their bottom-up modeling methodology tracks and reports national average PV system pricing for the major market segments. Their bottom-up methodology is based on tracked wholesale pricing of major solar components and data collected from interviews with major installers.

3.2.4 Tracker Cost Adder

A one-axis tracker slowly rotates the PV panels throughout the day, which increases their energy production by about 20%. Trackers cost more upfront than fixed-tilt structures and have slightly higher maintenance costs. The following are data points used to estimate a tracker cost adder above fixed-tilt.

- Local developers told us to add 10 to 25 cents to move from fixed-tilt to 1-axis tracker for a 1 MW system.
- GTM US Market Insight, Q3 2016: "The cost premium of tracking systems over fixed tilt is shrinking quickly. In Q1 2016, tracker systems carried a $0.17/W_{dc}$ premium over fixed-tilt systems. However, in Q2 2016 that premium shrunk to $0.13/W_{dc}$. Similar changes in hardware pricing should continue for the remainder of 2016"
- GTM US Market Insight, Year-in-Review 2016: "Quarter-over-quarter, the premium for single-axis tracking systems was unchanged at $0.12/Wdc."
- NREL Cost Benchmark report estimates adding a tracker in NC increases cost 5% and decreases the LCOE by 11% (which does not account for the value of improved peak demand reduction)
- GTM 2nd Half 20016 pricing executive summary: $1.06 utility fixed tilt and $1.22 utility tracked,

1 www.timesfreepress.com/news/business/aroundregion/story/2016/sep/23/epb-build-community-solar-chattanooga/388230/

2 www.nrel.gov/docs/fy16osti/67142.pdf

3 For more information on U.S. Solar Market Insight and to download this quarter's free Executive Summary, visit www.gtmresearch.com/solarinsight or www.seia.org/cs/research/solarinsight

or a $0.16/W adder.

3.2.5 Continued price reductions of PV

GTM US Market Insight, Year-in-Review 2016: "Utility fixed-tilt and single-axis tracking projects in Q4 2016 saw average pricing of $1.06/Wdc and $1.18/Wdc, respectively. That represents a 2.8% and 2.5% price reduction from last quarter. Quarter-over-quarter, the premium for single-axis tracking systems was unchanged at $0.12/Wdc. Within the utility-scale segment, pricing for fixed-tilt and single-axis tracking systems fell by 20% and 23%, respectively, year-over-year."
GTM US Market Insight, Year-in-Review 2016: "In the past few years, U.S. module price trends were largely driven by antidumping and countervailing duties on Chinese suppliers. Recently the main driver has shifted; current module price trends are largely a result of supply-demand imbalance. During the fourth quarter, the quarterly average delivered price for Chinese producers ranged from $0.38/W for order volumes greater than 10 MW to $0.39/W on the high side for order volumes of less than 1 MW. It should be noted that these prices do not represent the low end, since rapid module price depreciation drove a large difference between prices at the start and end of the quarter."

3.2.6 Solar Operations and Maintenance Costs:

Solar PV systems require minimal operations and maintenance. Much of the maintenance of a ground-mounted system is maintenance of the vegetation at the site. Industry practices also include preventative electrical maintenance conducted 1 to 12 times a year, including visual inspections, insulation resistance testing, and more. There is minimal published data on the O&M costs, and there is a wide variety of values reported, often varying by region of the country and system size. Different regions of the country require very different maintenance, for example, most systems on the east coast require regular grass cutting but rarely if ever require panel washing but systems in the desert require little vegetation maintenance and regular panel washing. A 1 MW ground-mounted system is a scale that could be considered either distributed-scale or utility-scale depending on the perspective and the context. The following are data points used to develop the O&M cost estimates in the model. The Solar Access to Public Capital Working Group published a Best Practices in PV System Operations and Maintenance[4] and more recently a 2nd Edition[5], that is becoming a standard industry reference. It is often not clearly stated whether or not an O&M cost figure includes replacement of PV inverters that have reached the end of their life. We have assumed these costs are not included in the O&M budget.

- An informal rule of thumb heard from local PV developers is an annual cost of $10 to 15/kW$_{dc}$
- In December 2016 NREL and other members of the SuNLaMP PV O&M Working Group published a 2nd Edition of their 128-page Best Practices in Photovoltaic System Operations and Maintenance report[6]. This report is a great resource to understand O&M practices, it also has a summary of past studies on O&M costs and this statement: "Members of the Working Group have discussed these results and are currently recommending 0.5% for large systems and 1% of system

[4] http://www.nrel.gov/docs/fy15osti/63235.pdf
[5] http://www.nrel.gov/docs/fy17osti/67553.pdf
[6] ibid

initial cost per year for small systems as a reasonable expectation of PV system O&M costs." 0.5% results in an annual O&M cost of about $9,625 or $8/kW$_{dc}$/yr. 1.0% results in an annual O&M cost of $19,250 or $16/kW$_{dc}$/yr.

- In May of 2016 the Department of Energy published The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs[7] in their On The Path to Sunshot series of reports. In that report they define the 2015 baseline annual utility-scale O&M price to be $15/kW$_{dc}$ (Fixed tilt) and $18/kW$_{dc}$ (Tracking). Their 2020 goal is $7 (fixed) and $10 (tracking).
- In February of 2016, the National Renewable Energy Laboratory updated their estimate of the operation and maintenance costs for grid-tied distributed generation scale (0 to 10MW) systems[8]. They say that these values are not to be interpreted as statistically significant, that they are mainly meant to provide rule-of-thumb information, accurate enough for a first pass screen of economic viability. The O&M cost information is mostly from interviews with industry experts and contractors. For projects 1 to 10MW in capacity, they report average fixed O&M costs of $16/kW and no variable O&M costs, with a range of fixed O&M costs of about $6/kW to about $26/kW.
- In December of 2015, EPRI published a 24-page report entitled "Budgeting for Solar PV Plant O&M: Practices & Pricing.[9] This is an excellent resource to become familiar with solar O&M and contracting for it. They report average annual system O&M costs at $20.50/kW$_{d}$c for fixed tilt silicon PV system and $21.50/kW$_{dc}$ for 1-axis tracked silicon systems, with a range of overall O&M budgets from $10 to $45 per kW per year.
- A DOE SunShot-funded PV O&M Working Group led by NREL, Sandia, and SunSpec Alliance has developed a prototype PV O&M cost proforma.[10] A public online version is expected as early at April 2017. Our team modeled the proposed PV system in the Version 1.0a of the spreadsheet and calculated a $12.09/kW$_{dc}$ annualized O&M cost for a fixed-tilt system. This version did not adjust the results for a 1-axis tracked system.
- Bloomberg New Energy Finance (BNEF) is currently benchmarking global utility-scale O&M costs at around $10,000/MW/yr, based on the latest calculations by developers, Jenny Chase, Head of Solar Analysis at BNEF, told PV Insider.[11]

3.2.7 Replacement of PV Inverter (capital cost):

Our model does not include the expected replacement of the system PV inverter(s) in the Operations and Maintenance budget, rather this cost is treated as an expected capital cost that will occur in year 15 of the project. Inverter prices for large central inverters or smaller 3-phase string inverters that could be used in

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[7] http://www.nrel.gov/docs/fy16osti/65872.pdf
[8] http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html
[9] http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006218
[10] http://sunspec.org/wp-content/uploads/2016/09/NRELSandiaSunSpecPVOMWorkgroupSep13.pdf
[11] http://analysis.newenergyupdate.com/pv-insider/us-solar-market-boom-cuts-om-costs-years-ahead-forecast

this project are in the range of \$0.08 to 0.25 per kW_{DC} today. During the first fifteen or so years of the project, it is widely expected that inverters will continue to experience price declines that more than offset any inflation pressure. We have conservatively assumed a \$0.15/kW_{DC} price for inverter replacement, including installation.

3.3 Battery Storage System Costs including O&M

Battery system prices are changing very quickly, making it difficult to precisely predict the price point of the proposed battery system. However, in the fall of 2016 we spoke with enough battery system vendors to be comfortable that our estimates are reasonable and somewhat conservative. Every new report or announcement in the utility-scale battery industry seems to report lower prices that are dropping faster than many predicted. Adding to the complexity of estimating battery prices is the variety of metrics that can be used to report pricing and the variety of what components are included in a price. Additionally, there are several different battery technologies available in the market with different characteristics that also makes it difficult to compare the pricing of all options head to head.
Lithium Ion batteries are dominating the utility-scale market (97% of 2016 installations[12]) in recent years, but there are also competing technologies that are showing some market viability such as lead-acid, flow batteries, and a saltwater battery. Most of the competing technologies tend to fare better in applications requiring many hours of energy storage. Lithium ion technologies excel for applications that need 0.5 to 4 hours of storage. Lazard's Levelized Cost of Storage Version 2.0 released in December 2016[13] sums up the levelized cost of storage for use in a distribution feeder application (20-year life, 500kW/1,500kWh (3 hours), 1 cycle per day for 200 days per year) that is very similar to the storage system proposed for PWC. While the Levelized cost of storage energy is not a metric used in our analysis, their industry-guiding analysis is a good reflection of the relative lifetime costs of the leading battery technologies in this application.

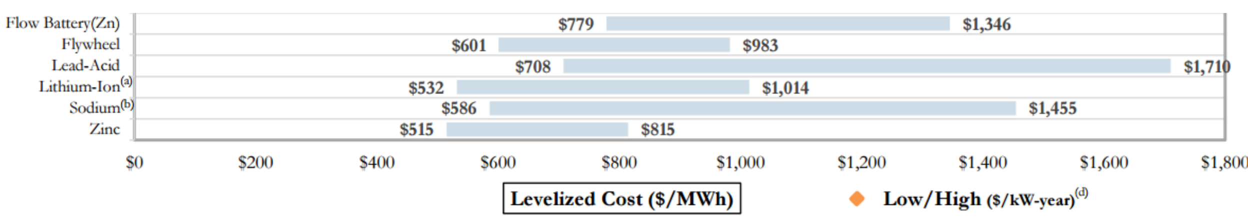

Figure 19: Levelized Cost of Storage (good metric to compare costs) for a 500kW with 3 hours of storage battery energy storage system in a distribution feeder application. (Source: Lazard's Levelized Cost of Storage, Version 2.0)

For the low end of the range in the figure above, the figure below breaks down the factors that make up the total Levelized cost of storage in this distribution feeder use case.

12 gtmresearch and Energy Storage Association, U.S. Energy Storage Monitor: 2016 Year in Review and Q1 2017 Executive Summary, March 2017

13 https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf

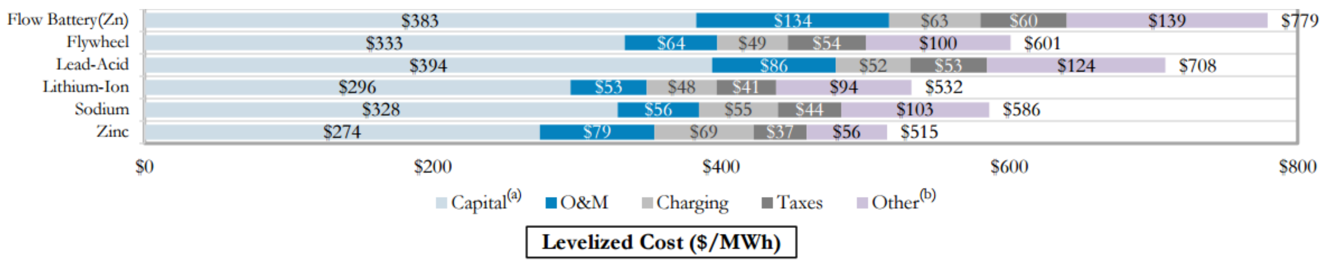

Figure 20: Breakdown of the low end of range of the Levelized Cost of Storage for a 500kW with 3 hours of storage battery energy storage system in a distribution feeder application. (Source: Lazard's Levelized Cost of Storage, Version 2.0)

Below are the default battery system costs used in our model, which assumes lithium ion technology.

Table 5: Nominal, Low, and High Battery System costs used in the model

System Costs	Nominal	Low	High
Total Installed Cost of Battery System ($)	$ 625,000	$ 475,000	$ 725,000
Total Battery System cost per kW	$ 1,250	$ 950	$ 1,450
Total Battery System cost per kWh	$ 625	$ 475	$ 725

Our research to estimate the expected cost of the proposed 500 kW / 1,000 kWh system was primarily conducted in the fall of 2016. The key data that lead to our battery system cost estimates are shown below:

- Lazard's Levelized Cost of Storage Version 2.0 capital cost ranges for a distribution feeder application (20 yr life, 500kW/1,500kWh, 1 cycle per day for 200 days per year). Note that these values are based on 3 hours rather than 2 hours of storage. (see Figure 19)
    - The CAISO Illustrative Value Snapshot which is a 1MW/2MWh system providing demand charge reduction by cycling to a full depth of discharge 80 times per year assumes an EPC cost of 16% of the AC and DC raw capital costs. 16% of $500/kWh is $80/kWh.

- According to GTM Research[14], in 2015 turnkey costs for the balance of systems (BOS) (everything other than the battery packs) grid-scale energy storage systems averaged $670 per kilowatt of capacity, broken down as $380/kW of hardware, $170/kW of soft costs, and $120/kW of Engineering, Procurement, and Construction (EPC). EPC work, including site preparation, rigging, shipping and installation, make up the smallest share of BOS costs and aren't expected to drastically shrink by 2020. $120/kW for EPC work applied to the proposed 500 kW battery system results in an EPC cost of $60,000, or $60/kWh for the proposed 1,000 kWh system.

- Tesla doubled the capacity of their commercial energy storage product the PowerPack in September of 2016. The pricing for their equipment, including containerized battery systems,

[14] www.greentechmedia.com/articles/read/grid-scale-energy-storage-balance-of-systems-costs-will-decline-41-by-2020

inverters, controller, and cabling and site support hardware. Their online price estimate for a 500 kW / 950 kWh system is $454,860, or $479/kWh, which does not include installation. Adding the $60/kWh estimated in the point above brings the turnkey total to $539/kWh.

- In a meeting with ABB's Business Development Management for Energy Storage representative at their booth at the Solar Power International conference in September, he estimated that they could provide a turnkey 500kW/1000kWh lithium ion system as I described for $600 to $700 per kWh of capacity.

- Our team visited PowerSecure on October 14, 2016 in Durham and discussed their services and the proposed system. At that time, they provided the following estimate to supply the proposed turnkey system: $600 to $700 per kWh of capacity, broken down approximately as $550/kWh for hardware only (in install), $80/kWh for inverter, and less than $300/kWh for the batteries.

- NREL November 2015 entitled Economic Analysis Case Studies of Battery Energy Storage with SAM[15] provides the following default costs for use in SAM models, defined as "Installation labor, margin, operation and maintenance, and other costs are captured as a function of the size of the installed PV system using the defaults in SAM. The battery bank is assumed to be DC connected such that battery power output is inverted to AC using the same inverter as the PV system."

Table 6: Default cost factors for PV plus Storage system in SAM (see explanation above about kW basis)

Variable	Value
Module cost	0.71 $/Wdc
Inverter cost	0.21 $/Wdc
Battery cost	$300/kWh Lithium Ion $255/kWh Lead Acid
Balance of system equipment	0.57 $/Wdc
Installation labor	0.15 $/Wdc
Installer margin and overhead	0.75 $/Wdc
Permitting	0.06 $/Wdc
Operation and Maintenance	20 $/kW-yr

o

- Project fact sheet about 2 MW/ 3.9 MWh battery system installed by Sterling Municipal Light Department (SMLD) in Massachusetts.[16] The total project cost reported as $2.7 million, or $692/kW for a project to be completed in 2016.

- EOS Energy Storage is offering a 1H 2017 pricing of $250/kWh for a single 250 kWh/1000kWh system, consisting of batteries, containerized package, battery management system, but not the power conditioning system (inverter). This system has an inherent 4-hour rating, meaning 2,000

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15 http://www.nrel.gov/docs/fy16osti/64987.pdf

16 http://www.energysterling.com/pdf/COMMUNITY_CLEAN_ENERGY_RESILIENCY_INITIATIVE_FACT_SHEET.pdf

kWh of storage are needed to achieve a 500 kW power capacity.

- o Industry article quote, January 2017[17]: "Batteries represent a significant portion of the performance and cost of an energy storage system," says Chris McKay, director of sales at Northern Power Systems. "By using the Eos Aurora, we can deliver a fully integrated ESS solution at an all-in, installed price of less than $400/kWh – depending on project size and location, but always with the quality, functionality and reliability that is characteristic of Northern Power. We believe this offering will allow more customers than ever to access the benefits of an on-site energy storage system."

- Aquion Energy, a saltwater technology, quoted a price of $914/kWh for a battery pack only.

3.3.1 **Battery Operations and Maintenance:**

Grid-scale lithium ion batteries are still a fairly new and maturing product, so unsurprisingly there is limited published guidance on the cost of to operate and maintain such a system. Here are the main sources we used to determine the battery and O&M costs for our model.

- In October 2016, Rocky Mountain Institute published The Economics of Battery Energy Storage.[18] In the report they follow several use cases, the one closest in size and use is a commercial demand-charge management system. Their cost models shows that the net present value of all costs are approximately 15% O&M with the rest capital costs. This ratio in our nominal-cost model is 19% O&M.
- The November 2015 paper from NREL on calculating battery economics using NREL's System Advisor Model (SAM) software has a default operations and maintenance cost of $20/kw$_{PV\text{-}DC}$/year for a combined PV plus storage system.[19]

- Lazard's December 2016 Levelized Cost of Storage Analysis _Version 2.0[20] provided a breakdown of lifetime storage costs, including O&M. (see Figure 20)

  - o Lazard's Levelized Cost of Storage Version 2.0: CAISO illustrative Value Snapshot for 1MW/2MWh project operating to a 100% depth of discharge 80 times per year is assumed to have an O&M cost of 1.6% of the total installed capital cost, escalating 2.25% per year. For the PWC project 1.6% of the battery system capital cost is $10,000 in year 1, which is equivalent to an annual O&M cost of $20/kW.

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17 http://solarindustrymag.com/eos-and-northern-power-integrate-energy-storage-solutions

18 http://www.rmi.org/electricity_battery_value

19 Economic Analysis Case Studies of Battery Energy Storage with SAM, http://www.nrel.gov/docs/fy16osti/64987.pdf

20 https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf

- October 2016 publication on reducing O&M costs from PV Insider addressed battery storage O&M saying:
    - "High-penetration states such as California and Hawaii are already actively pushing for solar to be paired with storage. The question for asset managers is: how does this affect O&M? The simple answer is: not much.
      In general, battery systems do not suffer from any of the issues around dirt, vegetation or tracker moving parts that plague PV. Nevertheless, says Dan Blair, director of technical services at ViZn Energy Systems, a flow battery maker: "Bidirectional inverters and switchgear require O&M schedules beyond typical PV inverters."

      Furthermore, he says, the most commonly used battery chemistry, lithium-ion, "requires aggressive monitoring and maintenance of added subsystems, such as fire control and environmental and safety systems, to prevent individual cells from overheating."

3.3.2 Battery Replacement Costs

Our model assumes replacement of the battery back in year 12 at a cost of \$337/kWh. In Lazard's Levelized Cost of Storage version 2.0, the Distribution Feeder use case assumes a DC replacement capital cost of \$189/kWh to \$313/kWh in year 10 and no other replace costs in its 20-year life.

3.3.3 PV and Battery Decommissioning

At the end of the life of the installed equipment the project will either be updated with new equipment and continue to operate, or it will be decommissioned. Decommissioning of a PV system is straightforward and not unlike reversing the installation process. Inverters, transformers, and their equipment pads are removed, PV panels are removed, racking is removed, pile-driven posts are pulled up, fences are removed, wires are pulled out, conduits are dug up, trenches are filled, and the site is reseeded. Nearly all of the equipment removed has some salvage value. The fencing and racking are all steel and aluminum that can be easily sold for scrap metal. The wires are copper or aluminum and can also be sold for scrap metal. The transformers and inverters have large amounts of steel, aluminum, and copper that can all be sold for scrap. The conduits and equipment pads will go to the landfill. The PV modules are the largest unknown. They are warrantied to still produce 80% of what they produced when installed after 25 years, suggesting a reasonable chance for a resale value as a working PV panel. The next most valuable use is to recycle the panel. It is possible to recycle over 90% of the materials in a PV panel. Today, panels are being recycled with a lower recovery rate than what is possible, yet today broken panels in NC are being purchased for a small amount for their recyclable value. Analysis by several different entities in NC, which has been reviewed by our team, show that the salvage value of equipment in a ground-mounted solar project more than pays for the cost to hire a general contractor to remove all of the equipment. As long as metals prices increase more rapidly than labor rates it could be expected that decommissioning a solar project will still be a money-making endeavor in the future. To be conservative, our model sets aside a \$60,000 (\$50,000 / MWDC) PV decommissioning fund. To put this value in perspective, the installation labor cost of the PV system is roughly \$0.15/kW_{DC} or \$180,000. There is less published about the decommissioning cost of a battery system, however its footprint is much smaller and many products on the market are fully containerized which makes removal quick. Similar to 25-year old solar panels, at the end of its life in this project the battery is still functioning with a significant amount of its initial capacity. We have assumed a net decommissioning cost of $20,000 for the battery system. To put this cost in perspective, the estimated Engineering Procurement and Construction (EPC) cost of the battery system, which includes much more than just installation, is about $70/kWh or $70,000 for the proposed project. Combined, the PV and battery decommissioning cost estimate is $80,000 which is modeled as a $80,000 decommissioning fund consisting of five payments of $16,000 per year in Years 21 - 25 of the project.

Results of Lifetime Model:
The lifetime model represents the proposed solar and storage system owned by PWC, bought with cash[21], with all of the energy and demand-charge savings providing 'income' to PWC. Defined in this way, the project breaks even in just under 11 years, provides an internal rate of return of 7.8%, and has a net present value of $1,200,000. The batteries receive about 83% of their charging energy directly from the PV system. The project lifetime cash flows are shown in the graph below.

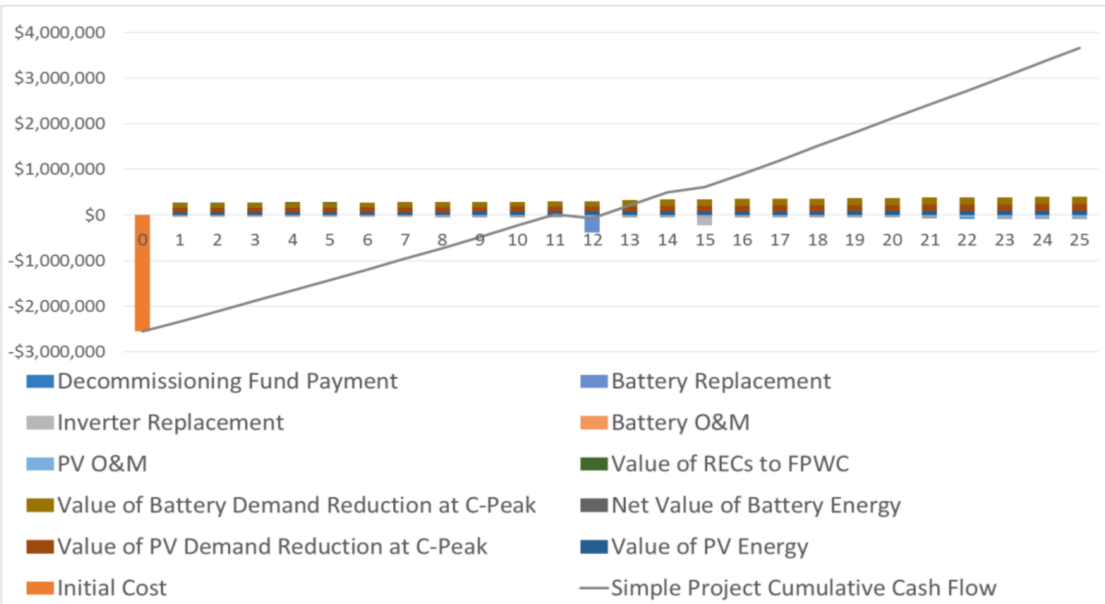

Figure 21: Lifetime Model (direct ownership by PWC, without a community solar program) system cash flows, including a project cumulative cash flow shown as a line that becomes positive around the start of year 11.

[21] Meaning that financing costs are not included in the model, however all NPV values assume a 4% discount rate

4 Validation of Hourly and Lifetime Models

The results of the lifetime model were validated by independently modeling the same PV plus storage system in the Department of Energy's System Advisor Model (SAM) software. This software is DOE's flagship renewable energy performance and financial modeling software, which is widely used and respected in the industry. The software is well established for modeling PV systems and in 2015 added the ability to include grid-scale batteries with a PV project. The model is quite sophisticated in its ability to technically model a system's performance. Its financial model is also quite sophisticated. However, it is limited in its ability to simulate real-world battery control, for which our custom spreadsheet was required. To control the battery in SAM we provided SAM with desired total load hourly data for the full modeled year which caused SAM to discharge the battery only during the peak hour each month.

5 Cost / Benefit Analysis of System Options

Before considering the impacts of a community solar system, this section provides an overview of the cost / benefit analysis of system options, with the goal of optimizing the system design to maximize financial returns to PWC while staying within the given constraints on the project. The key constraints are understood to be:

- Generation limits in PWC's Transmission and Generation contract with their wholesale provider may limit PWC-owned generation unless that generation is for compliance purposes.
    - Because this project produces RECs, which help PWC comply with REPS requirements, the PV generation in this project does not count against PWC's limited generation allowances.
    - Use of the battery storage system in conjunction with the PV system is also believed to generate RECs for REPS compliance by providing demand-side management.[22]
        - It is recommended that PWC discuss this situation with the Public Staff
        - The IRS has issued guidance that battery energy storage that receives at least 75% of its charging energy from PV is eligible for the renewable energy ITC. We designed the system to meet this federal definition of solar storage.
    - The system was initially designed with a $2 million budget, but feedback from PWC requested a larger PV system and accepted the accompanying higher budget.

The following are the primary design variables that were adjusted to find the optimal system design, and a summary of the chosen value.

- AC or DC coupling of PV and Storage: Both the PV panels and batteries are both direct current (DC) devices, so they can connect and share a single inverter, which is known as DC coupling. This has the advantage of saving the cost of a second inverter. In order for such a system to be able to provide the full capacity of both the PV and battery storage at the same time the inverter must be significantly oversized for use by the PV the rest of the time, which is not ideal. An AC coupled system has separate PV and battery inverters that are each optimized for the system they are serving. The output of each system is then combined before connection to the grid. The battery inverter also serves as a battery charger that can receive power from either PV or the grid.
    - AC coupled. This is most common design for PV + storage systems of this scale and aligns best with the equipment available. The system could potentially be designed as DC coupled by someone replying to the RPF.
- PV array capacity (kW_{DC}): a reflection of the peak power generating capacity of the PV panels
    - 1,200 kW_{DC} Initial system optimization conducted with a budget of $2 million dollars found that the system payback time could be minimized with a 500 kW PV array coupled with a 500 kW / 1,000 kWh battery system, however the payback period was not very

[22] § 62-133.8. Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Section: (c)(2), http://www.ncga.state.nc.us/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-133.8.html

sensitive to changes in this PV to battery capacity ratio. PWC requested that the PV system be increased to 1 MW (AC, which corresponds to 1.2 MW_{DC}), which increased the project payback time from 12.0 years to 12.4 years (using levelized inverter and battery replacement costs). However, this does not account for the likelihood that PV EPC costs will be higher per watt for the smaller system. There is addition benefit of making the system clearly PV dominated in terms of capacity.

- PV DC to AC ratio: the ratio of the power capacity of the PV panels (DC) to the power capacity of the inverter(s) (AC), some oversizing of the PV array is optimal because it is rare to experience the conditions needed for the PV array to output at its peak capacity. Too much array oversizing causes potential PV production to be wasted because it is more than the inverter can handle. Details such as whether to use a single large central inverter or many smaller string inverters should be left up to the EPC firms in the RPF process.
    - 1.2 DC to AC ratio: 1.2 is very common for 1-axis tracked systems. The final exact value will be determined by the selected EPC firm, but a 1.2 ratio is known to provide good value and therefore is appropriate for this stage of modeling.
- PV array mounting: The PV panels can be mounted in at a fixed-tilt at any tilt and orientation combination or they can be installed on a 1-axis tracker that tracks the sun from east to west each day.
    - 1-axis tracking: Two different fixed tilt options as well as a 1-axis tracker option were analyzed and the 1-axis tracker clearly provides the most value because it is not only able to significantly increase the PV energy production but it also dramatically increases the demand reduction value provided by the PV system.

- Battery storage technology/chemistry: Many different battery technologies are available at the scale this project needs, but many fewer have been implemented in adequate quantities to provide good market confidence in their value. Over 95% of recent grid-scale battery installations have used lithium ion batteries, consisting of several different lithium ion chemistries.
    - Lithium ion: For the purpose of the model lithium ion batteries have been chosen. Battery technologies and products are maturing quickly as prices are falling, so the best option at the time of development is not obvious at this time, although lithium ion is the clear front-runner.
- Battery power capacity (kW_{DC}): the maximum rate at which the battery can deliver energy, i.e. its power capacity. Different products are available in a varying array of capacities, so a specific desired capacity may not be available from every vendor but a similar capacity is likely available.
    - 500 kW_{DC}: Several factors affect the optimum batter capacity. Clearly, a larger power capacity means the ability to provide more demand savings, it also means a more expensive battery. A larger battery also makes it increasingly difficult to feel confident that 75% of the battery charging energy can be provided by solar. A larger battery improves the system economic metrics but drive the total system cost over the $2.55 million budget, at least at our nominal price estimates. At the low price estimate the 750 kW battery is within budget. Here are the results or a simple parametric study of several options:

- Hours of battery storage: Lithium ion batteries excel in applications that require 0.5 to 4 hours of storage. The hours of storage multiplied by the battery power capacity determines the battery's energy capacity (kWh),) which is the primary driver of much of the battery system costs. There is a balance needed of adequate storage to usually be able to discharge during the peak hour while not having a more expensive battery than needed.

5.1 Summary of Proposed System Specs:

1 MW_{AC} (1.2MW_{DC}) PV system
PV mounted on a 1-axis tracker
500kW/1,000kWh (2 hours) of Lithium Ion storage
$2.55 million initial capital cost
25-year project life

6 PWC Community Solar Program and Model

PWC is interested in implementing a community solar program utilizing a solar PV and battery storage system. This project would serve multiple purposes – customer engagement and financial savings, for example – though the primary intent is to satisfy a portion of PWC's North Carolina REPS requirements with utility-owned generation, rather than purchased RECs.

Based on discussions with PWC about the utility's preferences, NCCETC's base case modeling assumes the solar PV and battery storage systems are directly owned by PWC and not third party owned. The model also assumes that the community solar aspect of the project is designed as a subscription model to better accommodate Fayetteville's large transient population.

Multiple ownership /financing and program design options are available for a community solar plus storage project. PWC's three primary ownership/financing options are (1) **direct purchase**, (2) a **power purchase agreement (PPA)**, and (3) a **partnership flip**. A direct purchase is the simplest model, whereby PWC pays for the system in full and has full ownership of it throughout the project life. This option affords PWC the greatest degree of control over the system, yet is also the riskiest because PWC is responsible for operation and maintenance and will recover the investment based on system performance. As PWC is a municipal utility, PWC may not claim the federal Investment Tax Credit (ITC) if it is directly purchasing the system.

Through a PPA, a third-party developer would pay for and install the system and sell the power produced by it to PWC at a specified per kWh rate (and likely a separate demand reduction rate per kW of demand reduction achieved). Under this option, the private developer retains ownership of the system and is responsible for operation and maintenance. A private developer would purchase, own, and operate the project, making this a lower risk option to PWC. PWC would also incur lower risk because it would only be paying for the energy received. A PPA would allow a private developer to claim the federal ITC and potentially pass along a portion of this value to PWC in the form of lower per-kWh rates. A PPA, however, adds complexity to the project and can sometimes result in reduced overall savings, depending on the return that the developer proposes. PWC would also have limited control over the system.

Finally, a partnership flip ownership model allows for a partnership entity (typically an LLC) to own the system and allocate up to 99% of the financial returns to the third-party investor until the investor reaches their target rate of return, usually after 6 years. At this point, the financial allocations flip, with the host entity (PWC in this case) receiving the majority of the returns. Any time after this flip, the host (PWC) may purchase the small portion of the project owned by investors at a fair market value cost to become the sole partner in the LLC and therefore the sole owner of the project. Nearly all of the utility-scale solar projects in NC are developed using a partnership-flip arrangement that allows the available tax benefits to be monetized as effectively as possible.

In addition to financing choices, there are three primary program design models available: the first two are shared solar models requiring volunteer participants, a **subscription model** and a **purchase model**, and the third is simply treating the system as PWC-owned generation that is shared by all PWC customers. Under a subscription model, customers pay a monthly fee (flat or per kWh) to either receive solar energy produced by the community array or directly support and enjoy the benefits of this solar energy (depending on whether the utility or customer retains ownership of the "renewable energy certificates" associated with the solar energy.) Under a purchase model, customers pay an amount upfront to either own a portion of the solar array or own the power produced by their portion. A third option of the utility is using the solar energy as part of its general power mix and spreading any cost savings associated with system across all ratepayers; however, this is not traditionally considered community solar, as community members do not actively participate. This option may be called community-scale solar and its financials are represented by the project lifetime model.

An additional layer of customization comes from the battery storage system. The community solar program may only include the solar array, or it may include both the solar and battery storage systems. If basing customer bill credit rates on the financial value provided by the system, this decision will have an impact on these rates, and therefore, the attractiveness of the program to customers.

6.1 Overview of Community Solar Program (Base Case: PWC-Owned, subscription)

The total cost of the 1.2 MW_{DC} solar PV system and 500 kW_{DC}/1 MWh_{DC} battery storage system would likely be approximately $2.55 million, but could fall within the range of $2.125 million to $2.955 million. If PWC were to simply own the system and accrue the financial savings itself, rather than implementing a community solar program, PWC would break even in year 12.4 and achieve a net present value of about $1,200,000. Incorporating a community solar program as proposed would extend the breakeven point to year 16.8, and PWC would see a net present value of $0.

The 1.2 MW_{DC} system would contain a total of 3,692 panels if using 325 W_{DC} panels, each available as a "share" of the project (along with an equivalent fraction of the battery system). We propose that the monthly cost for a share of the community solar system be set such that over the 25-year life of the project

PWC exactly breaks even (i.e. PWC's NPV is $0 at a 4% discount rate). Specifically, PWC would make all of the capital investments, but upfront and inverter and battery replacements around years 10 to 15, and have these investments repaid over 25 years by monthly subscription fees. All of the value generated by the PV and battery system (energy cost savings, demand cost savings, REC purchase savings) less all of the operating costs (PV O&M, battery O&M, energy costs to charge the battery, community solar administration costs) are passed on to the subscribers in a monthly bill credit. Currently, one large unknown is the monthly cost to administer the community solar program. There will be some cost associated with customer service but the largest cost is likely to be related to processing each subscriber's bill credit, which could be handled manually or through software. The model assumes an annual administration cost of $10,000 that increases with inflation over time. Our estimate of this cost is primarily driven by a report by the DOE-funded Solar Market Pathways program on options for community solar billing for a similar project in Cook County.[23] They found the following options and annual costs to handle billing integration of community solar credits: semi-automated $8,000 per project, 3rd party software: $4,000 to $10,000 per project per year plus setup costs.[24] As directed by PWC, the model assumes PWC will self-insure the project and thus not have any annual insurance expense.

Using the nominal system price estimates, the monthly cost for community solar subscribers would be $4.13 per share and would remain static throughout the program. Depending on the specifics of the final project's cost and number of PV panels the size of each share to be defined to be a round dollar figure such as $5 or set based on the number of panels which is likely to result in a cost of about $4.13. PWC also has the option of setting a fixed annual escalation rate for the subscription cost that would have the effect of improving the economics for subscribers in the early years of the project while reducing the savings in later years.

Notably, the model projects that with a static cost subscribers will see a net financial benefit in the very first year of the program, and this net benefit will only increase over time.

[23] solarmarket pathways website for community solar support of Cook County (Chicago), http://solarmarketpathways.org/project/solarchicago/

[24] Utility Billing Impacts of Community Solar, https://www.cookcountyil.gov/sites/default/files/service/bill-crediting-analysis.pdf, May 2016

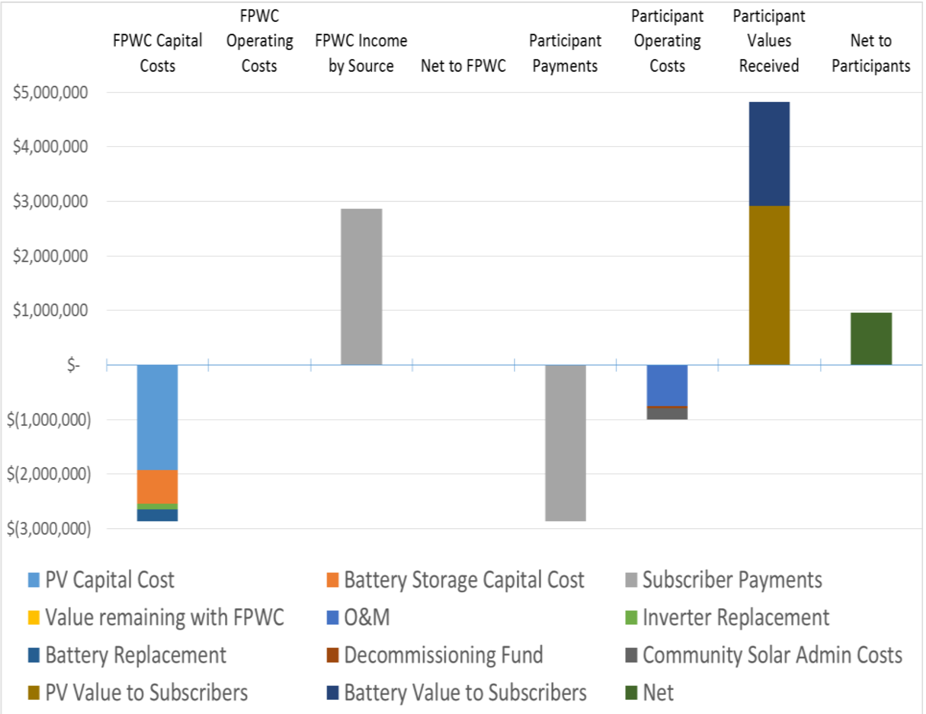

Figure 23: Project lifetime Net Present Values for PWC and for Community Solar Participants

6.2 Costs and Benefits from PWC Point of View

A summary of the costs and benefits of the proposed community solar project from PWC's point of view is provided at the start of the previous section and is also presented in the table below in comparison with other community solar options as well.

Table 10: Summary of Financial Results of Several Community Solar Program Options from PWC Point of View

	Direct Ownership, No Community Solar Program	Direct Ownership Subscription Model	Third-Party Ownership Subscription Model	Direct Ownership Purchase Model
Breakeven Year	12.4	16.8	21.3	1.9
Net Present Value	$1,200,000	$0	$125,000	($22,000)
Internal Rate of Return	7.5%	4.0%	8.6%	2.7%

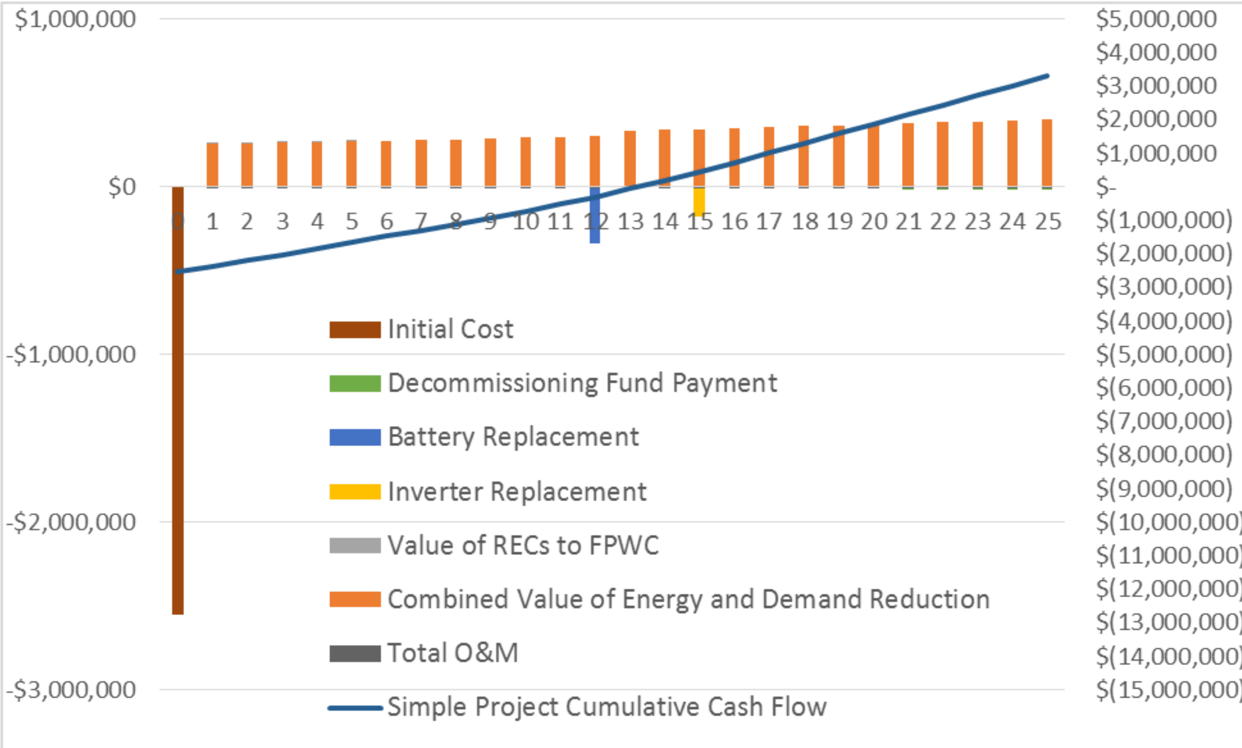

Figure 24: PWC-owned, subscription-based Community Solar Project cash flows from PWC point of view

6.3 Risks to PWC

PWC faces risk in making sure it fully subscribes the community solar program. However, for any unsubscribed shares, the value will accrue directly to PWC and costs will still be recovered through the savings provided directly to PWC. PWC can manage this risk by conducting a customer survey, as it has done, to gauge customer interest and price points. PWC can also maintain a waitlist so it can quickly fill open shares as customers leave the program.

PWC also faces the risk of future rate changes by Duke Energy. NCCETC's model assumes a 2.5% annual escalation rate for both the energy rate and the demand rate. If rates increase at a higher rate, the solar and storage project would provide greater value to PWC and subscribers than assumed in the model. However, if rates increase at a lower rate – or decrease – the project will provide less value than the model projects. Such a scenario seems very unlikely, but if this occurs to a point where subscribers are paying a premium each month, PWC risks losing subscribers and bearing any losses on its own.

Another risk borne by PWC and community solar subscribers is that of hitting the monthly system peak with the PV system generation and the battery storage system. The majority of the project's financial value is derived from demand savings. As PWC is only charged based on their demand during Duke Energy's hour-long monthly system peak, demand charge savings from the community solar project are only realized each month if PWC discharges the battery storage system during the system peak. Cycling the battery storage system wears it out, although at the projected 80 or so cycles per year most lithium ion batteries are expected to last for well over 10 years, if not 20 years. While it is ideal to limit battery cycles, additional cycles are not a major concern and are more than justified if they increase the likelihood of discharging during the peak hour. The primary challenge is determining when to begin discharging the battery. The Duke demand is nearly flat around its peak for many months of the year due to the nature of electricity demands as well as various energy customers attempting to reduce their demand at the peak hour. If PWC does not manage to hit the system peak frequently enough, subscriber bill credits will not meet the model's projections, and PWC could risk losing subscribers. Additionally, if demand shapes morph dramatically over the life of the project there is a chance that the peaks could move to times of more or less solar production. The demand shapes have remained rather stable over the recent decades but there is no guarantee that they will not change in future decades due to new trends in electricity demand, generation, or storage.

6.4 Cost and Benefits from Participant Point of View

Table 11: Summary of Financial Results Per Share from Customer Point of View

	Direct Ownership Subscription Model	Third-Party Ownership Subscription Model	Direct Ownership Purchase Model
Customer Cost per Share	$4.13 per month	$6.63 per month (avg.)	$637.50
Annual Value over Cost (Year 1)	$3.83	($0.28)	$51.32 (total Y1 credit)
Annual Value over Cost (Year 20)	$25	$15	$72 (total Y20 credit)
Breakeven Year	immediate	immediate	13.0
Net Present Value	n/a	n/a	$231
Cumulative Net Value (25 years)	$381	$213	$815

In year 1, participants would receive a monthly bill credit of $4.45, providing subscribers with a net positive $0.32 monthly credit on their bills. The monthly bill credit increases each year until reaching $6.27 in year 25, providing participants with a $2.14 net positive monthly bill credit in year 25. If a customer remained subscribed for the full 25 years, he or she would achieve a cumulative net value of $381 per share subscribed.

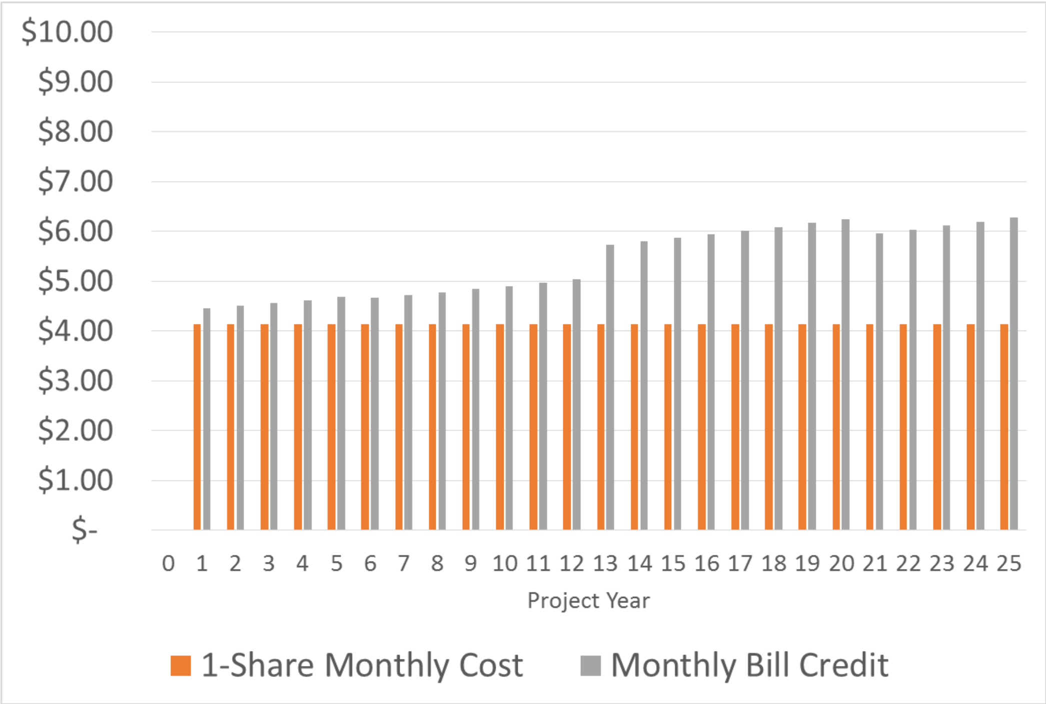

Figure 25: Subscriber Cost and Bill Credits by Year (Direct Ownership, Subscription Model)

6.5 Risk to Participants

Customers also face certain risks associated with a community solar program. The same risk of rate changes that applies to PWC applies to participants. If Duke Energy's rate increases at a rate below the 2.5% used in the model, customers would see a lower monthly bill credit. The subscription model provides much greater flexibility to customers than a purchase model, so customers are able to respond to this risk and leave the program should the bill credit become a bill premium. If PWC chooses to establish a minimum subscription length (typically 12 months), customers would be locked into the program for that period, but could leave at the end of the 12 months. Within the 12-month period, customers are unlikely to see changes to rates impacting the bill credit too significantly, and in a worst-case scenario would only be required to pay bill premiums for a few months.

Another risk to customers is the variable nature of the bill credit, apart from rate change variation. Values generated by the system will vary seasonally, with the system producing more energy in the summer months. PWC could calculate the bill credit on a monthly basis or estimate a flat annual value based on expected performance. Any differences between predicted and actual values could then be trued-up in the following year's rates. The value and thus the bill credit is also dependent upon PWC's ability to hit the monthly system peak with the battery storage component. As the majority of the project's value is derived from demand savings, not hitting this peak will result in a lower monthly bill credit for participants.

6.6 Other Ownership and Program Options

The base case described above assumes a community solar subscription program in which PWC directly owns the solar PV and battery storage systems. However, there are additional models available to PWC, some of which NCCETC modeled for comparison. The first of these is a purchase model, in which PWC still directly owns the system, but participants are able to purchase a share upfront and receive bill credits over the course of the program, rather than paying a monthly subscription fee. Under this model, PWC breaks even very early, due to the participants' upfront payments. This model results in a lower internal rate of return and a negative net present value to PWC, though. For participants, it would cost $637.50 upfront per share, and they would begin receiving a $51.82 annual bill credit in year one, which increases to $73.11 per year in year 20. A participant would break even after 12.9 years and save $815 over years 13 to 25, after paying back the purchase price.

Another option is third-party owned system where PWC signs a long-term Power Purchase Agreement (PPA) with the system owner to purchase the energy generated, delivery of demand reductions, and RECS. The advantages of this arrangement is that PWC has no upfront cost and bears little to no operational risk (depending on terms of the PPA). Additionally, this arrangement allows monetization of federal tax benefits, however under our assumptions of higher required rate of return and additional costs of property taxes and income taxes, the economics for the community solar participant is very similar to the PWC direct ownership model that forgoes use of available tax benefits. It is possible that our assumptions about the PPA rate required to interest a third-party are overly conservative, so PWC could consider allowing RFP respondents to provide bids based on a third-party ownership / PPA arrangement. This is a very common arrangement for co-operative and municipal utilities to develop utility-scale solar PV facilities.

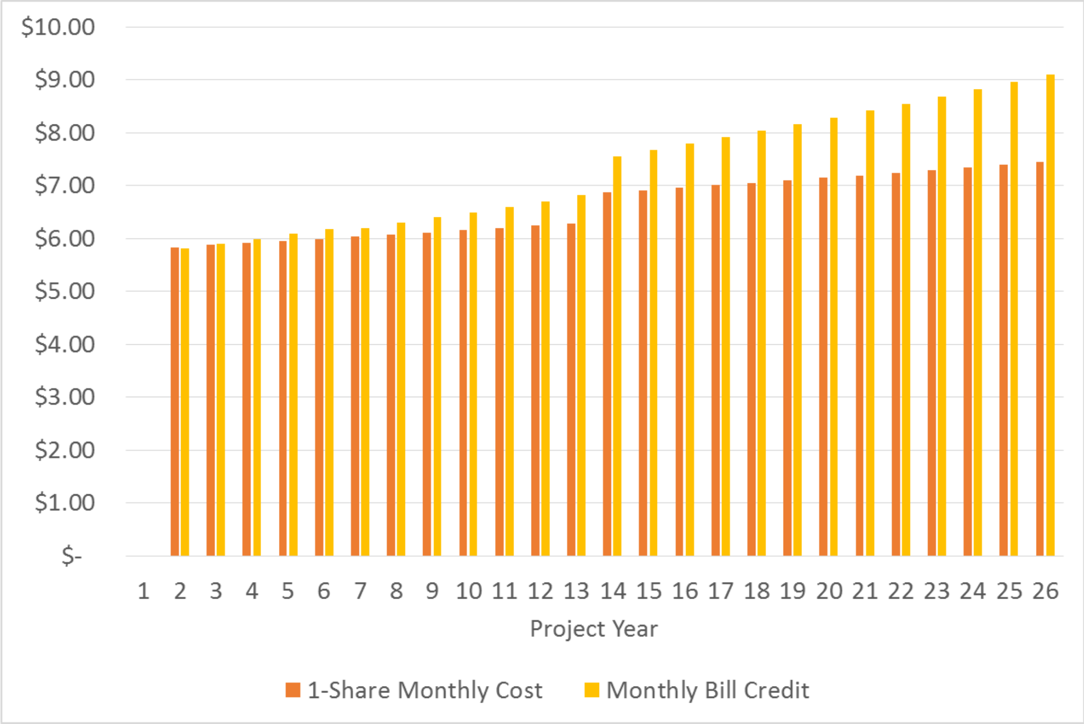

Figure 26: Subscriber Cost and Bill Credits by Year (Third-Party PPA, Subscription Model)

By far the most complicated, is the partnership flip option. While this ownership arrangement is quite complicated, it is a well understood and successful model for public / private development of PV facilities that allow use of available tax credits and for long-term ownership by the public entity. Due to its complexity and a lack of initial interest from PWC, this option has not been included in the cost benefit model. However, our team recommends that you consider allowing RFP bidder to propose a partnership-flip option because we feel that there is good chance that it could provide an attractive development path for PWC and your customers.

Finally, the simplest option is to not add any volunteer-based community solar program to a PWC owned system. In this case, the values from the system stay with PWC and therefore benefit all of your customers. There are obvious benefits of simplicity and cost savings of avoiding potentially complicated billing for community solar subscribers. The downside is that a system without any ability for individual customers to voluntarily participate will not be able to meet the desires of some customers seeking more significant involvement with solar energy generation.

7 Community Solar Program Design Considerations

7.1 Program Models

In designing a community solar program, there are several different models and design elements to consider. The two primary program models, as described earlier, are a subscription model and a purchase model. Under a subscription model, participating customers pay a monthly fee (either flat or per kWh) and receive kWh credits or monetized credits for energy produced by their share of the community solar array. Under a purchase model, participants pay an upfront cost to own a share of the community solar array or the power produced by this share, and then receive credits over the course of the program.

A subscription model allows more customers to participate because it does not require an upfront payment and or certainty that the customer will remain in PWC service territory long enough to recoup their investment. The disadvantages to a subscription model are that there is less cost recovery certainty for the utility, and if the monthly subscription fee is higher than current retail electricity rates, it may be difficult to attract participants. Our model suggests this will not be a problem, but this could occur if the project underperforms or the electricity cots from Duke Energy do not rise at the modeled rate.

A purchase model typically offers similar benefits to purchasing a rooftop solar system but at a lower cost and also provides greater cost recovery certainty to the utility. However, the disadvantages to a purchase model are that it is more complicated to handle customers moving out of the service territory and participants may be limited if customers do not have the cash upfront to participate. As of August 2015, approximately 73% of utility-sponsored community solar programs in the U.S. utilized the purchase model, 17% utilized a subscription model, and 10% took a hybrid approach.[25]

As PWC is considering a battery storage connected to the solar project, PWC also has the options of limiting the community solar program to the solar array, or including the battery storage component in the program as well. By limiting the program to the solar system, the program would be less attractive to customers, as a large portion of the overall project's value is derived from storage-induced reductions in demand, but financial benefits could be passed along to all ratepayers. An additional option of forgoing a customer-facing community solar program and passing along financial benefits of the complete solar plus storage project to all ratepayers is also available. This option is simpler and can save administrative expenses, but distances customers from the project and may not satisfy customer demand for solar options.

After making decisions on the overall program design, there are many more detailed design elements to consider. *Note: Much of the following information on design considerations is derived from the Smart Electric Power Alliance's* Community Solar Program Design Models *report, published in 2015.*

[25] Solar Electric Power Association, *Community Solar Program Design Models* (2015): http://www.solarelectricpower.org/media/422095/community-solar-design-plan_web.pdf

7.2 REC Treatment

Determining whether the utility or the customer will own the renewable energy certificates (RECs) associated with the energy produced by the solar array is an important decision. If the utility owns the RECs, they can be used toward compliance with North Carolina's renewable energy and energy efficiency portfolio standard (REPS). However, if the utility retains ownership of RECs, participating customers may not make the claim that they are purchasing solar energy, and the utility may not advertise the program as such. Conversely, if customers own the RECs, the energy produced may not be used toward REPS compliance (this may therefore also put the project in conflict with supply contract terms), but participants may make official "green claims."

7.3 Customer Eligibility

Some community solar programs may limit the types of customers that are able to participate in the program. Oftentimes programs will be limited to residential customers or residential and small commercial customers, as larger customers require a greater amount of capacity to make a significant impact on their usage.

7.4 Program Length

The length of the community solar program can have a significant impact on a program's financial attractiveness, particularly for a purchase model. Typically, programs will guarantee customers credits for 20 to 25 years.

7.5 Minimum Term

Some programs require customers to participate for a minimum length of time. This is particularly useful for a subscription program, in order to avoid customers signing up and leaving the program within a month or two. Subscription programs typically require customers to participate for a minimum of 12 to 24 months.

7.6 Deposits

PWC may want to consider collecting a deposit from customers if opting for the subscription model. The can be helpful to ensure cost recovery if a customer moves out of the service territory before the minimum term is up.

7.7 Participation Limits

Many community solar programs have limits on the amount of capacity an individual participant may purchase or subscribe to. This limit may be a hard capacity limit or may be based on individual customers' usage. The most common approach is to establish a limit that is a percent of the customer's monthly energy usage.

7.8 Moving & Transferability

It is very likely that some community solar participants will move out of FWPC's service territory before the program concludes. Under a subscription model, this is less of a challenge, particularly if a deposit is collected. With a purchase model, however, customers may be hesitant to participate if no options exist to recoup their investment if they must move out of PWC territory before the program concludes. Some programs allow participants to transfer their shares to other customers or to sell them back to the utility. In general, customers prefer flexibility and options, but this adds complexity and cost for the utility.

7.9 Customer Financing

If a purchase model is used, PWC should consider whether it would like to offer financing options to customers or not. Some utilities offer on-bill financing to expand access to customers who may not have cash upfront to purchase a share of the community solar project. This helps to overcome one of the drawbacks to the purchase model, but adds complexity and administrative cost for the utility.

7.10 Treatment as a Security

Note: The following is for informational purposes only and does not constitute tax advice. Please consult with an attorney for greater certainty.

Participation in a community solar program has the potential to be classified as a financial security and thus be subject to regulation by the SEC. This topic is introduced in detail in the NREL April 2015 publication titled Shared Solar: Current Landscape, Market Potential, and the Impact of Federal Securities Regulation.[26] An additional resource on this topic is a 2009 memo from Stoel Rives LLP to NREL on Securities Law Issues Relating to Community Solar Projects.[27]

7.11 Tax Issues

Note: The following is for informational purposes only and does not constitute tax advice. Please consult with an attorney for greater certainty.

Multiple tax questions arose when exploring community solar program design options. The first is if monetized credits received by participants would be categorized as taxable income. These credits would not be treated as taxable income as long as they are reducing the customer's electric bill. If the amount of the credits were to exceed the total electric bill, that portion in excess of the bill would be taxable income unless credits are allowed to roll over from month to month.

The second tax question that arose was if a customer's contribution to the program could be considered a charitable donation. This would not be allowed because the customer is receiving electricity (or bill credits) in return for their payment.

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[26] http://www.nrel.gov/docs/fy15osti/63892.pdf

[27] http://www.solaripedia.com/files/699.pdf

The final tax question is if a customer purchasing a share of the community solar project is able to claim the federal Investment Tax Credit. This would be highly unlikely and would require the customer to physically own and have complete control over the panels that they own. Even this is uncertain and would require IRS clarification.

Conclusions and Next Steps

7.12 Bottom line for PWC and for Participants

Our analysis shows that the opportunity identified by PWC to build a solar and battery storage system to help meet their customers' desires to support solar energy generation has the potential to provide economic benefit to both PWC and its customers. This is an exciting result validated by also modeling in the Department of Energy's leading renewable energy analysis software, System Advisor Model (SAM) (see Section 4) and with careful due diligence estimating project capital and operating costs (see Section 3). The opportunity for a non-profit utility to produce net savings with a utility-owned solar PV system is a new reality made possible by recent dramatic cost declines in both utility-scale solar PV systems and utility-scale battery energy systems.

Throughout the cost / benefit analysis process our team has worked with PWC to receive feedback and guidance as the analysis progressed. Using this guidance and the optimization model, the proposed solar and storage community solar system is as follows:

- 1 MW_{AC} Solar PV system mounted on 1-axis trackers (1.2 MW_{DC} of PV panels)
- 500 kW Battery Energy Storage System with 2 hours of storage (1,000 kWh energy capacity)

The proposed community solar system is structured so that PWC installs and owns the system, and financially breaks even over the first 25 years of the project. PWC recovers this investment by splitting the project into about 3,700 shares (1 share for each solar panel) and charging about $4.13 per share per month for 25 years. Using a 4% discount rate, the net present value of the initial cost of the system and planned inverter and battery replacements in 10-15 years is equal to the net present value of 25 years of monthly subscription payments. In exchange for their monthly subscription fee, each subscriber receives a monthly bill credit equal to the value generated by the project (kWh generated by the solar system and peak demand savings provided by both the PV system and the battery system) minus all system operating costs. Our model predicts that this monthly bill credit will by slightly higher than the monthly fee in the first year of the project, and since the fee will remain the same for 25 years yet electricity rates are expected to increase, the net benefit to each subscriber is expected to increase over time.

7.13 Next Steps: Project Development and Procurement Process

As PWC and our team have discussed, the plan for PWC to procure the desired PV and Storage system is for PWC to release a Request for Proposals (RFP) to select a developer/EPC to provide a turnkey solar and battery storage system. PWC will coordinate with the chosen vender to perform the various project development tasks outlined in Figure 18. Our team strongly recommends a Design/Build RFP in which the required project specifications provided in the RFP are only the true project requirements, such as project site and nominal system specifications (as outlined in this report). This approach allows the responding developers the needed flexibility to provide the most competitive project that they can. Our partner on our Department of Energy Community Solar in the Southeast grant project, Rocky Mountain Institute (RMI), has found great success helping small utilities and local governments source low cost solar via competitive design/build RFPs. RMI has offered to support our team in the development of a RFP template designed for PWC, based on their experience running nearly a dozen similar RFPs over the last 18 months.