Altering Utility Grid Interconnection Policies for Community Renewable Energy Facilities

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DISCLAIMER

The author conducted this study as part of the program of professional education at the Frank Batten School of Leadership and Public Policy, University of Virginia. This paper is submitted in partial fulfillment of the course requirements for the Master of Public Policy degree. The judgments and conclusions are solely those of the author, and are not necessarily endorsed by the Batten School, by the University of Virginia, or by any other agency.

"On my honor as a student of the University of Virginia, I have neither given nor received unauthorized aid on this Applied Policy Project."

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ABBREVIATIONS

CE – Community Energy

CIAC – Contribution in Aid of Construction

CREA – Community Renewable Energy Act

CREF – Community Renewable Energy Facility

DCSEU – D.C. Sustainable Energy Utility

DER – Distributed Energy Resources

DOEE – Department of Energy and the Environment

FY – Fiscal Year

IEEE – Institute of Electrical and Electronics Engineers

LMI – Low to Moderate Income

NEM – Net Energy Metering

NPCS – New Partners Community Solar

NPV – Net Present Value

NREL – National Renewable Energy Laboratory

PV – Photovoltaic

REC – Renewable Energy Credit

REDF – Renewable Energy Development Fund

RIM Test – Rate Impact Measure Test

RPS (or RPS Act) – Renewable Portfolio Standard Act of 2016

SCAP – Solar Alternative Compliance Model

SfA – Solar for All

SITC – Solar Investment Tax Credit

SOS – Standard Offer Service

SREC – Solar Renewable Energy Credit

VNM – Virtual Net Metering

EXECUTIVE SUMMARY

The District of Columbia's energy policies and utility rules should create an enabling environment for achieving the goals of the city's Solar for All Initiative. Solar for All is a community solar program established by the Renewable Portfolio Standard Expansion Amendment Act of 2016 is intended to increase the amount of solar energy generated in the District and to provide the benefits from locally generated solar power to small businesses, nonprofits, seniors, and low-income households. The program is tasked with reducing by at least 50% electric bills of 100,000 low-income households in Washington, D.C. with high energy burdens by 2032 (DOEE, 2017).

Efficient and low-cost utility grid network interconnection is critical to Solar for All programs since community solar relies on net metering to share the financial benefits of solar energy generation. In 2015, the District ranked 33rd out of 34 utilities in terms of time required for interconnecting small-scale solar (MDV-SEIA, 2015). In addition, interconnection to the grid is costly and there is a lack of transparency and cost-predictability. In most solar cases, interconnection fees borne by the solar array owner makes sense. However, for third-party owned systems like community solar, where the benefits are distributed to low-to-moderate income (LMI) residents and the tax credits are internalized to the tax equity investor, the fees are unnecessarily burdensome. In addition, interconnection to the grid oftentimes requires distribution system upgrades – which benefit the entire grid but the high fees are borne by the solar developer. All interconnection costs – including timeline delays and lack of transparency – adversely affect the amount of benefits that are being shared with the District's low-income residents and thus a reduction or elimination of these costs exponentially benefits the reach of the Solar for All program.

This report provides New Partners Community Solar with options to further improve the Community Renewable Energy Facility (CREF) development as the nonprofit and other Solar for All grantees navigate the costly and unpredictable interconnection processes. To this end, this report presents and analyzes the projected impacts of three CREF-specific interconnection policy options:

I. Shift the burden of responsibility for grid interconnection fees onto the utility
II. Alter interconnection requirements so that a CREF may operate behind-the-meter
III. Improve process clarity through Solar Interconnection Agreement pilot program

The policy options are evaluated based on criteria pertaining to projected effectiveness, a cost-benefit analysis, political feasibility, and equity. Based on the evaluation, it is recommended that the DOEE and Solar for All program adopt alternative III: a pilot Solar Interconnection Agreement modelled off of California's Rule 21 and New York's recent pilot program. This Solar Interconnection Agreement incorporates a 25% cost certainty envelope and publication of historical costs and unit cost guides. This alternative prioritizes cost certainty, considering that other alternatives to reduce the cost to the developer present cost equity issues related with cost shifting to the non-solar rate base.

PROBLEM STATEMENT

Over the last decade, the U.S. solar market achieved an average annual growth rate of 54% (SEIA, 2018). Despite this growth, there are technical and social barriers to solar development. Communities who adopt solar are typically 1) higher income earners, 2) corporations working to offset their emissions or satisfy a triple bottom line, or 3) those with industry insight and knowledge of the polices, engineering, and financial benefits of solar installation. On the other hand, solar photovoltaic (PV) systems are only effective in zones with full sunlight and room for development. In fact, only 22-27% of residential rooftop area is suitable for hosting on-site PV systems (Coughlin, et al., 2010). The location-specific limitations, combined with the information and financial barriers, such as low rates of return and upfront capital costs, present equity issues. According to a Natural Resources Defense Council Report, low to moderate income and minority groups are frequently excluded from the solar energy market. Oftentimes, renewable energy use is not feasible for those who will be most disproportionately affected by the negative impacts of climate change and greenhouse gas emissions (Stamas, 2017). Community Energy (CE) is one potential solution in the face of these market inequalities. CE aims to ensure that the switch to renewables does not leave out the most vulnerable: those without the means or incentives to develop renewable energy systems.

While community solar, a specific subset of CE, is a promising tool for expanding solar access, it does not automatically create or ensure development and low-income participation. Barriers to entry, including development financing and interconnection cost predictability and transparency are prevalent for community solar. Policy guidelines developed by Low Income Community Solar recommend that such a program should clearly inform developers and subscribers of any charges and costs of grid modernization and interconnection (Low Income Community Solar, 2016).

Interconnection costs imposed by the utility must require careful consideration of the propriety of any proposed fee. According to the International Renewable Energy Council, the imposition of even a modest fee can substantially alter the economics of smaller, grid-tied distributed generation systems. High costs, as well as process delays and cost uncertainty, present significant barriers to project development (IREC, 2017). In Washington, D.C., the continued growth of the distributed solar market spurs the need for electric utilities as well as regulators and other stakeholders, to consider alternatives and improvements to the interconnection process.

A key trait of community solar is that the shared-ownership nature of the system provides benefits to the community beyond electricity generated. Benefits include distribution system upgrades and grid modernization from the interconnection of new Community Renewable Energy Facility (CREF) developments to the utility grid. The increased volume of interconnection requests and the evolving market for CREFs in Washington, D.C. necessitated the establishment of a Public Service Commission (PSC) working group to review Pepco's interconnection requirements. Under D.C. City Council Order No. 19676 in 2018, the RM9 Net Energy Metering Working Group was tasked to work on CREF-specific interconnection rules and deadlines.

BACKGROUND

Community Solar

Community solar refers to local solar photovoltaic (PV) arrays shared by multiple community subscribers who receive credit on their electricity bills for their share of the renewable energy produced. Since 2013, over 1,220 megawatts of community solar projects have been installed – the capacity to power over 200,000 homes (Solar Energy Industries Association, 2018). Community or shared solar models allocate the electricity of a jointly owned or leased system to offset the individual consumers' electricity bills, allowing multiple energy customers to share in the financial and electrical benefits of a single community solar array (Feldman, Brockway, Ulrich, & Margolis, 2015). This solar model is being rapidly adopted nationwide, as 42 states have developed – or plan to develop – community solar projects, capitalizing on the benefits of renewable energy (SEIA, 2018).

The National Renewable Energy Laboratory (NREL) estimates that 49% of US households are currently unable to host PV systems. This estimate excludes households that do not own their building or do not have access to sufficient roof space to host a PV system. Additionally, NREL estimates that 48% of businesses which have sufficient roof space to operate a PV system are unable to host for a multitude of other reasons. By opening the market to these customers, community solar could represent 32%–49% of the distributed PV market by 2020, thereby leading to growing cumulative PV deployment growth in 2015–2020 of 5.5–11.0 GW, and representing $8.2–$16.3 billion of cumulative investment (Feldman, Brockway, Ulrich, & Margolis, 2015)

Community solar programs are being increasingly adopted by states and forward-looking utilities who want to connect more consumers with clean energy. Presently, 16 states and the District of Columbia have statewide community shared solar policies in place, although policy structures and resulting market impacts vary widely (Solar Energy Industries Association, 2018). According to "The Vision for U.S. Community Solar: A Roadmap to 2030," community solar comprises the fastest growing segment of the US solar market. This GTM Research study, analyzed the market potential for US Community Solar through 2030, calculating capacity growth of 57 GW to 84 GW, serving 6.4 million to 8.8 million subscribers. The estimations are contingent on assumptions of strong community solar adoption policies and enabling market forces (Vote Solar, 2018).

Upfront costs and customer financing are important market incentives for the development of community solar. A study sponsored by the Office of the People's Council in Washington, D.C. on the value of solar found that the costs of solar in the District of Columbia have fallen markedly in recent years. In 2006, a typical 4 kW solar array cost approximately $36,000, installed. In 2016, the cost for a 4 kW system was approximately $13,000. Despite the rapid decline in prices, the study's surveys found that solar PV still represents a considerable investment with high up-front costs that many customers cannot afford. Due to high interconnection and installation costs, third-party ownership models have increasingly gained popularity and represent the dominant model for new solar installations (Synapse Energy Economics, Inc., 2017).

Virtual Net Metering

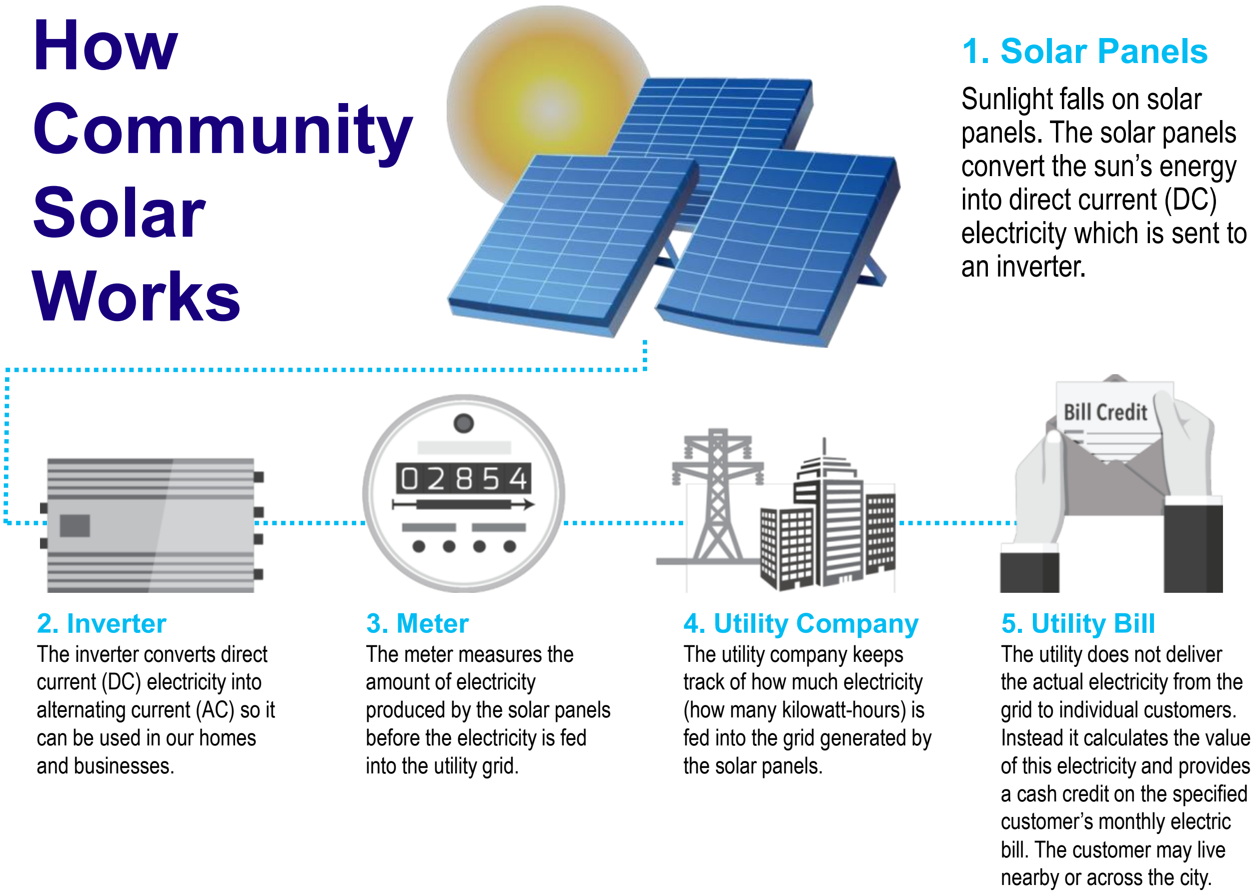
A critical component to lucrative solar development is the energy policy of net metering. Net metering services, established by the Energy Policy Act of 2005, asserts that "electric energy generated by [an] electric consumer from an eligible on-site generating facility and delivered to local distribution facilities may be used to offset electric energy provided by the electric utility to the consumer during the billing period" (EPAct2005 at § 1251a). In essence, net metering is a billing arrangement that allows a customer to offset on-site electricity use by receiving credit for excess electricity supplied to the grid from an on-site distributed generation system (IREC, 2017).

Virtual net metering (VNM) allows entities to offset their electricity load through generation located at a different location – i.e. a community solar facility. VNM allows multiple customers to receive electricity bill credits from a net-metered facility, which may be on-site or off-site. Because VNM standards are established within a state's net metering policies, the bill credits are typically valued a local retail rate. VNM enables shared solar program programs but the eligibility and requirements vary state by state. For example, in Massachusetts, multiple customers may share the bill credits generated by a remotely located facility. However, some states like California, limit VNM eligibility to more closely resemble traditional, on-site net metering where credits are only available to multi-tenant customers sharing an on-site solar facility. In Washington, D.C., Pepco offers Net Metering throughout its entire service area (Energy Sage, 2019).

WASHINGTON, D.C. COMMUNITY SOLAR

The District of Columbia's Solar for All program, established by the Renewable Portfolio Standard Expansion Amendment Act of 2016 (the "RPS Act"), is a comprehensive low-income targeted solar program. The RPS Act, which went into effect on October 8, 2016, requires 50 percent of retail utility sales sourced from renewable energy by 2032, with a 5 percent carve out requirement for solar energy. The RPS Act also established the Renewable Energy Development Fund (REDF), a special purpose fund for renewable energy in the district and financed through RPS compliance fees paid by electricity suppliers or utilities (DOEE, 2017). Under the auspices of this RPS Act, the Solar for All program intends to increase the amount of distributed solar energy in the District and to provide the benefits from locally generated solar power to small businesses, nonprofits, seniors, and low-income households. The program, funded by the REDF and administered by the District's Department of Energy and Environment (DOEE), aims to provide the benefits of solar electricity to 100,000 low-income households, and reduce their energy bills by 50% (based on the 2016 residential rate class average) by 2032. (D.C. Law 21-154 63 DCR 12926). Low-income households are defined as households at or below 80% of the Area Median Income (Department of Energy and Environment, 2017). Solar for All program grantees encompass single-family projects, multifamily affordable housing projects, community solar projects and, tangentially, local solar workforce development.

Figure 1: DC Community Solar Process Map



In late 2017, DOEE granted Solar for All funds to nine solar development organizations, including New Partners Community Solar (NPCS), in partnership with the utility Pepco. Under the terms of NPCS' $2 million USD grant, the project will install solar panels on 15-25 commercial, nonprofit, and apartment rooftops in Washington, D.C. (Department of Energy and Environment, 2017) All of the financial benefits of the energy production will be allocated in net metering billing credits and given to approximately 650 low-income families in Washington, D.C. at no cost for at least 25 years. The present Solar for All program and grant allows NPCS to rapidly expand their model of community solar for LMI households that has been in effect since 2017 (Moyer, 2018). In 2017, NPCS was also the beneficiary of the DOEE community solar pilot program which provided $175,000 in grant funding for NPCS to pilot the district's first community solar project. The D.C. Sustainable Energy Utility (DCSEU) will administer Phase Two of Solar for All, starting in 2019. DCSEU issued requests for proposals in late 2018 to build community solar projects. Moving forward, it is imperative that developers addresses the financial challenges and economic incentives of CREF development to ensure the greatest degree of benefits for LMI subscribers (DOEE 2017; Public Service Commission, 2019).

Phase 1: Innovation Grants

- 2017: DOEE Issued 9 innovation and expansion grants
- Engaged in interagency projects
- Plan to develop 10-12 MWs of solar by 2020 (including 8MWs of CREFs)

Phase 2: DCSEU contract

- 2019-2021: DCSEU to develop approx. 5-6MW of CREFs annualy
- To date, 2.3 MW of CREF solar completed
- 50-70 additional CREFs anticipated by end of 2019

Market Structure & Policy Development

Legislation to establish community net metering and the community solar program, specifically the Community Renewables Energy Amendment Act (CERA), was passed unanimously by the D.C. City Council in 2013. This law gave all utility ratepayers access to on–bill community solar credits for any community solar system they subscribed to or owned. The Public Service Commission, however, did not credit transmission and distribution charges as part of the community solar credits. This meant community solar subscribers would earn significantly less than what they would if they went solar by installing panels on their home. Instead, they would only receive a portion of the full net metering credit for solar. They would receive the full rate minus taxes, fees, distribution and transmission rates. This undercut rate has resulted in few community solar projects developed in the city since 2013. In 2016, the D.C. Council passed legislation to ameliorate this problem, successfully bringing the rate for community solar in line with the rate solar homeowners receive (Solar United Neighbors, 2017). The current credit rate equals the full Standard Offer Service (SOS) rate of $27.42 per month for General Service Low Voltage Non-Demand Customer (New Partners, 2017).

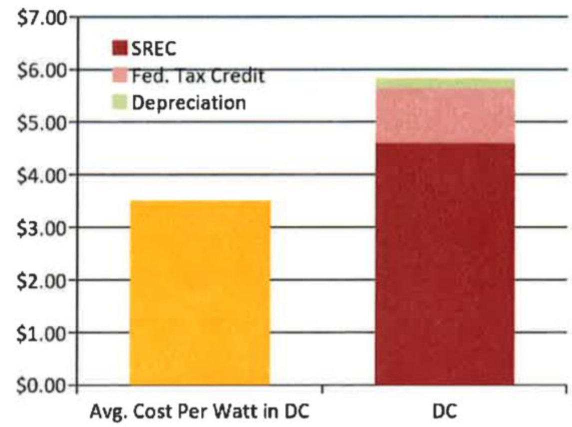
Interconnection Requirements

Pursuant to Section E of the Community Renewable Energy Amendment Act of 2013 (CERA), the owner or operator of each community renewable energy facility must follow interconnection procedures. Specifically, Section H of the Amendment states that "the amount of electricity generated each month available for allocation as subscribed or unsubscribed energy shall be determined by a revenue quality production meter installed and paid for by the owner of the community renewable energy facility. It shall be the electric company's responsibility to read the production meter" (D.C. Law 20-47). In 2015, the District ranked 33rd out of 34 utilities in terms of time required for interconnecting small-scale solar (MDV-SEIA, 2015). Since then, Pepco engaged in substantial reductions in interconnection timelines, outlined in their 2016 Interconnection Report. The report recommended improvements to their application process, including streamlined procedures, increased customer education and outreach, expedited technical review, and electronic data interchange (Pepco Holdings LLC, 2016). Presently, interconnection times take about 80 days in total. There has not been an updated ranking study since Pepco began implementing their streamlining procedures in 2016.

Cost of Solar

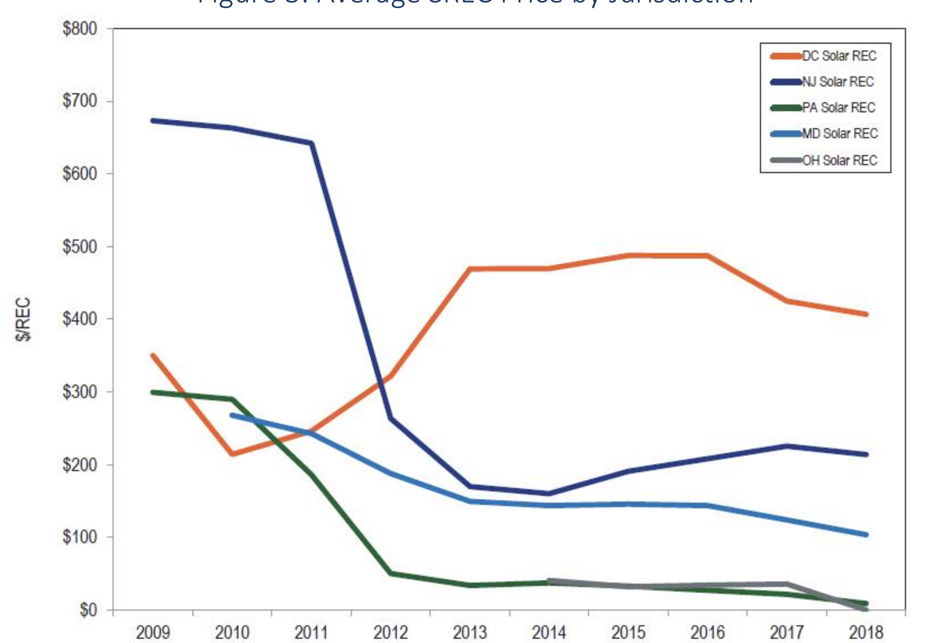
Washington D.C. is unique in that renewable energy policies and financial incentives cover more than 1.5x the average cost of solar, whereas states like New York and New Jersey cover 0.75x and 1x the cost of solar, respectively. As seen in Figure 2, the average cost per watt of solar in Washington, D.C. is $3.50 but the financial credits per watt are about $5.75 (DOEE, 2017). Developing a 50-kW system would cost approximately $175,000 prior to interconnection costs or grid distribution system upgrades but generates $287,500 in financial credit.

Figure 2: Cost of Solar in Washington, D.C.



This solar-enabling investment environment in the District of Columbia is spurred by value of Solar Renewable Energy Certificates, or SRECs. SRECs are certificates similar to Renewable Energy Credits (RECs), but specific to solar electricity (Whited et al., 2017). The utility must obtain SRECs to account for solar electricity production under the RPS Act's solar carve-out. For every megawatt hour (MWh) of electricity that a solar energy system produces, a corresponding SREC is created. SRECs can be bought and sold to transfer the right to count solar electricity. As shown in Figure 3, the SREC value varies by jurisdiction, with process from $50 to $300 across the United States. In Washington D.C. specifically, each 1 megawatt hour of energy generated by a solar facility corresponds to a $470 SREC in the form of a certificate that the utility, Pepco, pays generators (Energy Sage, 2019). SRECs cannot be bought or sold outside of the utility's service area – preventing customers who generate MWh of solar energy in other states from selling the energy in Pepco's territory for a higher SREC value.

Figure 3: Average SREC Price by Jurisdiction



While current financial incentives motivate solar development, there are considerable market volatility concerns. As the supply of solar energy generation in the city increases, as projected, the SREC value will decrease, and may drop significantly. When the Renewable Portfolio Standard solar carve-out target of 5% is reached, SREC prices will fall to a market-driven value rather than remain near the Solar Alternative Compliance Payment (SACP) value. The SACP is the penalty price that utility must pay per SREC if they fail to file the required number of SRECs by the end of each compliance period (SRECTrade, 2019). A breakdown of these fees and market requirements are provided in Appendix A. Until the solar carve-out target is reached, SRECs will be closely linked to the Alternative Compliance Payment cap, which begins at $500/MWh and declines to $300/MWh over time (Office of the People's Council, 2017). There is no price floor for SRECs in the District of Columbia, decreasing long term predictability of the local SREC market. Additionally, the price fluctuation in alternative energy prices (oil, natural gas, wind, etc.) drives price changes in solar energy. (Energy Sage, N.d.)

Pepco electric utility rate for Washington, D.C. as of April 2019 are as follows:

- ***Transmission Charge***: $0.12 per month. In excess of 30 kWh: $0.00665 per kWh
- ***Distribution Charge per kWh***: $13.00 per month. Summer: $0.00759, $0.02166 in excess of 400 kWh. Winter: $0.00769, $0.01512 in excess of 400 kWh.
- ***Generation charge per kWh***: minimum charge: 2.27 per month; $0.07266 per kWh

Under Pepco's net metering contract, if the solar system is under 100 kW then owners will be credited at the full retail rate of transmission and distribution charges. If the system is over 100 kW it will be credited at the generation rate. These credits never expire and their value, in the case of community solar, is directly passed through to the LMI beneficiaries. The city's production limit is 5 MW for community renewable energy facilities and 1 MW for residential and commercial customers (Pepco Holdings LLC, 2019).

Utility Rate Setting

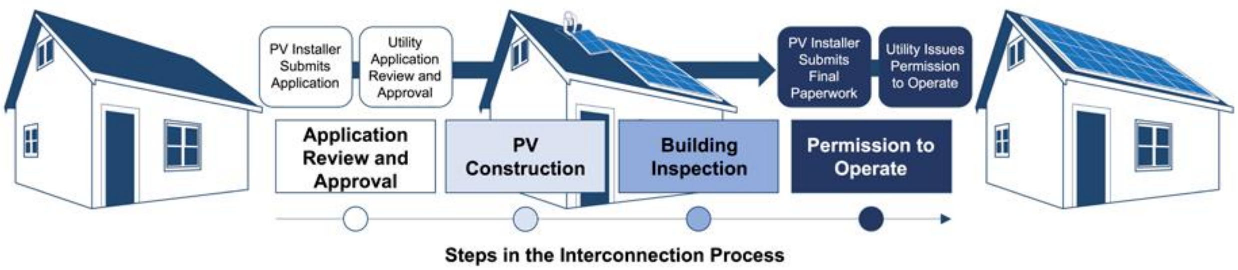
Community Renewable Energy Facilities (CREFs) can potentially impact a utility's ratemaking process through financial incentives and associated administrative costs, interconnection and integration costs, billing and related administrative costs, and distribution demand capacity or standby costs (Solar Market Pathways, 2017). The utility's rate base is the "total of all long-lived investments made by the utility to serve consumers, net of accumulated depreciation." It includes capital investments as well as interconnection processes, grid modernization updates, and adjustments for working capital. In the conventional ratemaking process, the utility's primary concern is establishing its revenue requirement. This is the total amount of revenue the utility would need to cover its expenses, plus costs in its rate base, on which it is eligible to make an approved rate of return. Distributed solar resources and CREFs impact the utility's revenue requirement, especially if the utility has a large enough share of distributed solar on the grid to create an identifiable impact.

IMPLICATIONS OF INTERCONNECTION

Interconnection and Grid Modernization

Solar interconnection is the utility-managed process of connecting PV arrays to the electricity grid network. Interconnection procedures are the "rules of the road" for any distributed generation connecting to the grid. The multi-step process outlined in Figure 4 requires engagement between CREF developers, the utility's Green Power Connection team, and the Public Service Commission's regulatory requirements. Typically, if distribution system upgrades are required to interconnect a project safely, costs are allocated to the project that triggers the upgrades. Designing an equitable cost allocation strategy that does not discourage interconnection presents a regulatory challenge.

Figure 4: Steps in the Interconnection Process (NREL, 2018)



If interconnection procedures are not designed to process applications efficiently, they can serve as a major bottleneck for new solar programs. As solar policies develop nationwide, interconnection standards have lagged behind – lacking consistent parameters across the United States. Interconnection technical issues were addressed through the development of national standards, including the Institute of Electrical and Electronics Engineers' (IEEE) 1547 *Standard for Interconnecting Distributed Resources with Electric Power Systems*. The federal government, through the Federal Renewable Energy Coalition, provides guidance on interconnection policy's technical aspects and enforcement. Distribution-level interconnection issues are in the domain of the state or city council and the responsibility of the utility and solar project developer. Fees for inspections on faulty interconnection procedures were reduced with more widespread recognition of relevant codes and standards, such as the aforementioned IEEE 1547, NEC Article 690, and UL 1741. In Washington, D.C., interconnection is regulated by the Public Service Commission. The larger volume of solar installations is also leading to new approaches in data transparency designed to inform utility customers and PV installers about local grid conditions and the potential costs and benefits of siting PV and other Distributed Energy Resources (DER) in certain locations on the grid.

The interconnection of a CREF with the utility's distribution system constitutes a Service Connection and is governed by Pepco's General Terms and Conditions. Under these terms, Pepco requires CREF developers, who are classified as "Commercial-Industrial" customers, to pay upfront for the costs of interconnecting the CREF. This payment, known as contribution-in-aid-of-construction (CIAC), directly offsets the cost of the service connection and results in no change to Pepco's rate base (Public Service Commission, 2019).

Interconnection Costs

Interconnection to the grid is costly. While Pepco does not release historical interconnection charges, NPCS' interconnection costs for solar developments in 2017 ranged from $3,000 for smaller facilities to $10,000 for larger facilities. The 2017 NREL U.S. Solar Photovoltaic System Cost Benchmark report estimates permitting, inspection, and interconnection (PII) costs to be $0.11–$0.16 per watt[1] for commercial rooftop systems with an average size of 10 kW to 2 MW (NREL, 2017). For example, a developing a 1 MW capacity solar PV system costs $160,000 to interconnect.

In the District of Columbia, a customer is responsible for studies and upgrade costs associated with interconnecting a system. Some states indicate that a utility is required to make a "nonbinding, good-faith" cost estimate, but this language does not hold a utility to a clear standard. As a result, a CREF developer may experience a significant escalation in interconnection costs if upgrades are required or if upgrades cost more than the utility originally estimated. To help address this issue, states including California, Utah, and Oregon have adopted cost envelope provisions. California, with the adoption of Rule 21, limits developer responsibility for upgrade costs 25% above the utility's estimate. Utah's cost envelope does not increase cost certainty as much as California's program because it only applies to study costs, which represent a smaller share of interconnection costs. Oregon's cost envelope is nonbinding, so it does not increase cost certainty for developers, although it may give a developer recourse if actual upgrade costs vastly exceed the estimate (Bird, 2018).

The conventional approach to allocating interconnection costs is commonly referred to as the "cost causer pays" method. Under this arrangement, the solar development applicant is required to pay for all costs, including the full cost of distribution system upgrades deemed necessary to accommodate the project. Benefits of this method are that it is simple in execution and provides a location-based signal that can encourage or discourage projects in a certain location based on the scale of necessary grid upgrade costs. The "cost causer pays" model has significant shortcomings including a free-rider problem, procedural delays, and potential project termination, explained below (Peterson, 2019).

> **Free Rider Problem:** Future projects also benefit from the newly upgraded circuit yet are not incurring any associated costs, putting the burden of paying for network upgrades entirely on the first DER applicant to trigger the need for a new facility (the cost causer).
> **Procedural Delays:** Attempting to avoid, reduce, or clarify unexpected upgrade costs through further feasibility studies and negotiations may backlog the interconnection queue.
> **Project Termination:** Smaller projects may be unable to shoulder the financial burden of high upgrade costs. High costs may result in upgrades never being done, because they are not economic for any individual project, although they could be economic if the costs were spread across a group of projects.

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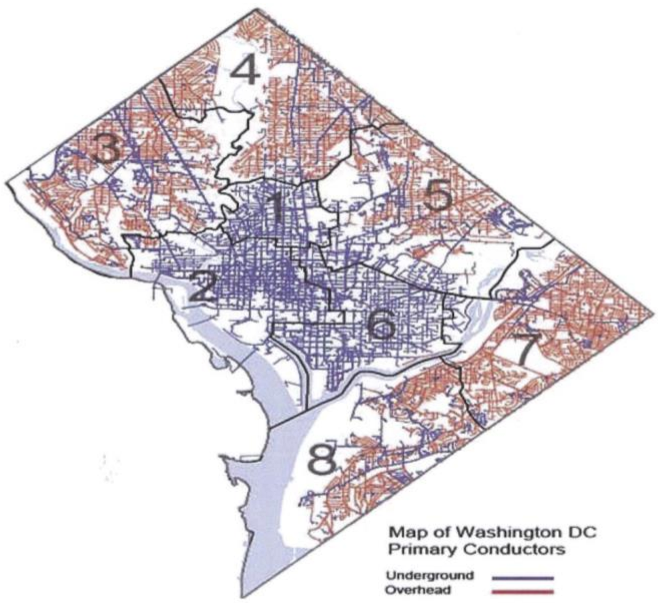
[1] PII Costs Calculated: construction permits fee, interconnection, testing, and commissioning. Includes assumed building permitting fee of $400 and six office staff hours for building permit preparation and submission, and interconnection application preparation and submission (NREL, 2017)

The DOEE reports that Solar for All grantees experienced cost estimates fluctuations up to two times initial interconnection estimates. The same report highlighted delays and inconsistent processes which increased risk and decreased valuation of CREF projects. In response to this, the DOEE tasked the RM9 Net Energy Metering Working Group to work on CREF-specific interconnection rules and deadlines. RM9 established that there are two categories of costs faced by the utility in interconnecting CREFs: (1) service line drops utilized by the CREF, and (2) distribution system level upgrades to accommodate a CREF and any later distributed energy resources (Public Service Commission, 2019). The average cost of underground and overhead distribution system upgrades for FY 2017 – FY 2018 was $10,000 and $4,355, respectively. Figure 5 provides an illustrative map of the type of distribution system across the District. The average size of these projects was 55 kW (Brown, 2018) For both types of costs Pepco presently seeks payment for all of these costs of the upgrades from the CREF developers.

Figure 5: Distribution System Map



In addition to service costs, the working group and CREF developers cite time management costs and uncertainties as preventative factors in CREF development to meet Solar for All's goals. While there is a significant amount of information on the Pepco website regarding CREFs, there is a lack of information conveyed about the interconnection costs. CREF developers do not receive an itemized list of costs – nor does Pepco publish unit cost guides, historical cost data, or interconnection cost components. Once a cost estimation is sent to the developer, stakeholder engagement through emails and phone conversations is necessary to gain further clarification on cost specifics. Time considerations with regard to interconnecting new solar are also extremely important to CREF developers because of tax credit investments. In order for the investor to receive solar tax credits in the calendar year, the solar array must receive Permission to Operate (PTO) from the utility by December 31st. Otherwise the tax credits cannot be claimed by the investor until the following year. As the Solar Investment Tax Credit (SITC) decreases over the next few years, interconnection times could seriously impact CREF development. The CREF budgets for development are counting on a certain amount of financing from tax credit investors to fund the project. A loss of this investment because of delays of interconnection from Pepco could be a significant barrier to development (Public Service Commission, 2019.

METHODOLOGY

The purpose of this report is to propose, analyze, and evaluate policy options that address the interconnection process and rules for CREFs in Washington, D.C. The next section introduces four evaluative criteria that were used to evaluate the proposed policy alternatives. The rest of the report focuses on three distinct policy options to reduce costs and increased transparency of interconnection, and makes a recommendation based on thorough analysis. Each section that follows will provide a description of the policy alternative and an evaluation using common criteria. After introducing each proposal and addressing potential concerns, the analysis will explore tradeoffs, advantages, and disadvantages of the options through a direct comparison and a detailed outcomes matrix. The options will be prioritized per the evaluative criteria outlined below. The last section of this report will recommend the option with the greatest potential to address the interconnection issues explored above.

EVALUATIVE CRITERIA

The following criteria will serve as evaluative measures to assess the projected outcomes of each proposed alternative policy option. Please note that the impacts and costs of policy options will be evaluated only as they pertain to District of Columbia residents, Pepco, and DC Solar For All Grantees. While interventions in the policy options may be accessible by other energy facility development, this policy analysis aims to estimate the effect of interventions on CREF development and interconnection, specifically.

Effectiveness

This criterion measures each alternative against its effectiveness at achieving the stated 2016 Solar for All program's goals and the Renewable Portfolio Standard set by the District of Columbia. The predicted success at reaching 100,000 LMI households and reducing their energy bill by 50% by 2032, compared to the counterfactual of not altering the interconnection process, will illustrate effective policy change. The goals of expanding solar access are tied directly to the efficiency of policy developments and inefficiency of current interconnection methods. The effectiveness criterion is evaluated at *high, moderate, or low*.

Cost

This criterion will project the costs of each alternative based on a review of policies, literature, and discussion with industry experts. Total costs, as well as the separate costs to the utility and to the CREF developer, are presented. The full value of benefits will reflect the utility's avoided costs for energy, capacity, and ancillary services, but it should also reflect other values such as avoided environmental and health impacts, avoided fuel cost and fuel supply risk, and market price effects. Proper accounting for these benefits of renewable energy production requires analysis of changing the interconnection standards (McConnell and Beaton, 2017). Community solar interconnection cost categories include those related to technological infrastructure, publicity, and time costs to developers and utility employees. Costs, represented in Net Present Value, are aggregated over a 13-year period through the end of 2032 and are measured as *high, moderate, or low*.

Political Feasibility

Based on the District of Columbia City Council's legislative history, a stakeholder analysis and interviews, implementation, and administrative capacity, this criterion will outline the degree of realistic feasibility for each alternative. By aggregating these factors, the impact of political feasibility will be evaluated on whether or not the proposed policy will obtain likely, unlikely, or uncertain support. For continuity, this criterion is measured as *high, moderate, or low political feasibility*.

Equity

The measurement of equity in this analysis is bounded to a specific set of stakeholders: the solar developers, LMI beneficiaries, the utility, and broader ratepayers. Equity will be measured by responsibility to pay for energy efficiency based on total energy use, predicted benefits of community solar, and imposing the lowest costs to the least number of consumers as possible. Equity also includes freedom of choice, engagement in process, and fair and efficient information. Equity will be evaluated on how the alternative generates *high, moderate, or low equity*.

Assumptions:

Effectiveness, equity, and cost criteria are estimated under the following general assumptions:

- The number of retail customers presented in Pepco's 2016 rate case filing was 290,362 customers, with average residential customer usage of 664 kWh/month (see Appendix B)
- The rate of return for Pepco is 7.45% (pursuant to Order Number 19433)
- The average cost before financial incentives for a 50-kW system is approximately $175,000, this system also generates $287,500 in financial credit (from SRECs and Federal Tax)
- Average permitting, inspection, and interconnection (PII) costs for commercial rooftop systems (average size 10kW to 2MW) are $0.11–$0.16 per watt (Fu, 2017)
- The average cost of underground distribution system upgrades for projects that both went forward and were withdrawn in FY 2017 – FY 2018 was $10,000. The average size of these projects was 39.44 kW. (Brown, 2018)
- The average cost for overhead distribution system upgrades for projects that both went forward and were withdrawn in FY 2017- FY 2018 was $4,355. The average size of these projects was 55 kW (Brown, 2018)
- The total required CREF capacity development under Solar for All is 240-300 MW by 2032 (DOEE, 2017)

The cost-effectiveness analysis assumptions, methodology, and sensitivity analysis are further detailed in Appendix C and the attached spreadsheet.

ALTERNATIVE I: SHIFT CREF GRID INTERCONNECTION FEES ONTO THE UTILITY'S RATE BASE

New community renewable energy facilities will not bear the costs of interconnection. Rather, interconnections to the distribution system for these specific CREFs operating under the auspices of the RSA Act and Solar for All will be financed by the utility company, Pepco. The utility will recover these capital costs through distributing them across the rate base.

In most solar cases, interconnection fees borne by the solar array owner makes sense. However, for third-party owned systems like community solar, where the benefits are distributed to LMI residents and the tax credits are internalized to the tax equity investor, the fees are unnecessarily burdensome. Since the benefits, energy, and credits from solar are directly distributed to LMI beneficiaries (through utility credits) and the utility (through satisfying RPS requirements), the non-profit managing entity may waive responsibility for any costs incurred by Pepco, such as costs associated with power flow, distribution system upgrades, or fees charged by Pepco, such as the Pre-Application Report Fee and interconnection. In 2017, New Partners Community Solar was charged $27,000 and National Housing Trust – another Solar for All grantee – was charged $22,430 to interconnect community solar projects in the District (Public Service Commission, 2019. Any costs and fees, such as these, would be recovered solely through a rate base proceeding by the utility. Additionally, the benefits of costs saved by the CREF developer would be passed along to LMI subscribers in the form of a higher utility bill credit.

Currently, the Procedural Manual for Implementation and Administration of Community Renewable Energy Facilities outlines the rules for generator facility interconnection. It requires any solar generating faculties to follow Pepco's Standard Interconnection Application' process as defined in Title 15, Chapter 40 of the D.C. Municipal Regulations for Small Generator Interconnection Rule (SGIR). Furthermore, "to participate in Community Net Metering as a CREF the Generator Owner will be required to execute a standard Interconnection Agreement with a CREF Addendum" (Pepco, 2017). The CREF Addendum supplements the standard interconnection agreement between a solar developer and Pepco. This alternative shifts the standards of the procedural manual's second order regarding CREF Addendums, allowing certified CREFs to interconnect without the standard interconnection fee. The utility, Pepco, would assume this fee, adding it to the utility's rate base with their guaranteed 7.45% rate of return (Order Number 19433). The rate base is then calculated into the overall rate requirement, spread across all utility bill payers.

A CREF-specific alternative fee structure is unprecedented in other states or districts across the country. However, there is no language in the District of Columbia Community Renewable Energy Amendment Act of 2013 (CREA) preventing such a structure. Furthermore, D.C. Code section 34-1435 allows "the local distribution company to recover actual dollar-for-dollar prudently costs incurred… in complying with a mandated renewable energy portfolio standard… may cost recovery under this section: may be in the form of a nonbypassable surcharge to current applicable customers." This section permits the utility company to "recover" these interconnection costs from the ratepayers and not to charge them upfront to the CREFs. (New Partners Community Solar Testimony, 2018). Implementing this responsibility shift requires necessary steps including system upgrades to allow for these interconnections and studies on the most efficient way for Pepco to recover these costs.

Due to the preventative price of interconnection in Washington D.C. for LMI-benefitting community solar facilities, stakeholders suggest that the burden of responsibility for grid interconnection should be borne by the regulated utility – not the CREF. This alternative recognizes that, at the onset of the Solar for All program, many industry participants believed Pepco's electric distribution system was robust enough to allow for interconnection of small generators without cost. Additionally, these industry participants, CREFs, and Solar for All grantees have already incurred significant costs in developing solar facilities. These interconnection fees and costs are assumed to be first-mover developments, informing community solar policies and procedures, and would not be recovered (New Partners Community Solar Testimony, 2018).

Alternative I: Analysis

Effectiveness

This alternative generates a **high effectiveness** at achieving the Solar for All program goals. Lowering the cost to developers for installing CREFs incentivizes increased CREF development of current and future Solar for All Grantees. Additionally, the project costs saved result in a higher value of the average utility bill credit for LMI subscribers and beneficiaries. Implementing this alternative could potentially direct the aggregate saved costs from interconnection fees to Solar for All subscribers, increasing the amount of utility bill credits.

The effectiveness of this measure is dependent on full targeting of LMI customers by the Solar for All program. Since the costs of interconnection would be passed along to Pepco's rate base, all LMI customers who are *not* subscribers or beneficiaries of a CREF program would incur disadvantages from program expansion. The DC Solar for All Implementation Plan calculated 114,455 low income households in the district, 23,000 of whom reside in master-metered buildings and do not receive electric bills (Department of Energy and Environment, 2017). If the program goal of 100,000 LMI customers is entirely met, this will offset the aggregate disadvantage of interconnection costs to Pepco's rate base, providing more solar benefit than harms to LMI customers, specifically.

Cost

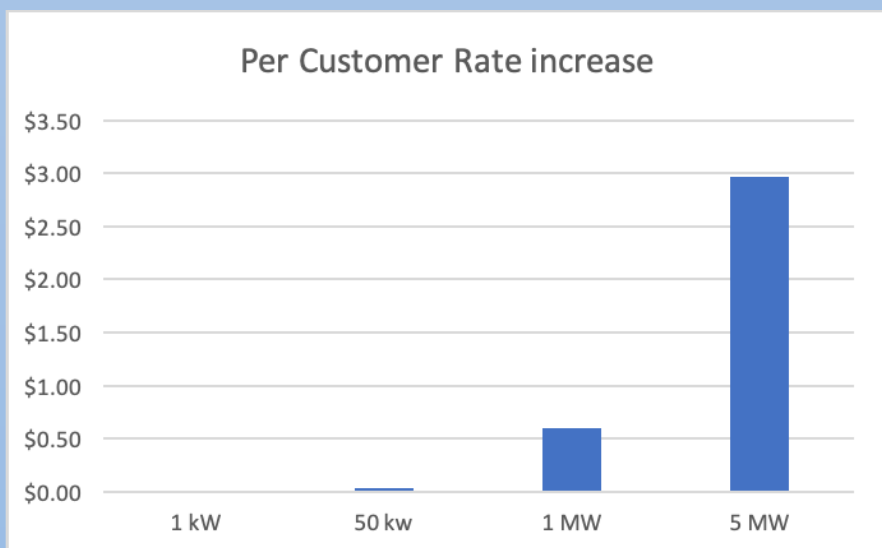
This alternative is a **moderate-cost alternative** since it functions as a transfer payment – where the cost of service does not change and no additional goods and services are being altered. The responsibility to pay is shifted from one party to another. Since Pepco's rate base is internalizing the costs of interconnection, cost-equity is a concern. The breakdown of imposed costs is as follows. A more in-depth analysis of the cost breakdown and methodology provided in Appendix C.

The **distribution of costs** is critical to the efficacy of this alternative and the evaluation of cost-benefit implications. Appendix C provides a full discussion of the distribution of costs.

- Pepco: *low cost*, specifically the administrative load of internalizing into rate base
- CREF developers: *low to zero cost*, as the fee is assumed by the utility
- District of Columbia rate base*: moderate cost* as ratepayers will face a marginal rate fee of $0.59 per 1 MW of CREF capacity developed, in 2019 dollars.

To satisfy the total capacity requirements of Solar for All (estimated 300 MW of CREF solar), individual retail customers will face total fees of $52.77 to $68.20, in 2019 dollars, depending on how the 300 MW capacity development is divided over all program years. The entire rate base faces a NPV of costs ranging from $15,321,505 to $19,801,488, depending on how the 300 MW capacity development is divided over all program years.

Figure 6: Per Customer Rate Increase[2]



Political Feasibility

This alternative has **low-moderate political feasibility** based on a collection of assessments. Considering the R9 task force is designed to address CREF-specific cost issues and the DOEE is invested in reaching the city's RPS and Solar for All goals, there is considerable openness on this issue for rule and standard improvements. However, this cost-shift has not been undertaken before by U.S. utilities so there is a dearth of impact studies to assess potential program outcomes. Political feasibility is dependent on how Pepco manages increased costs across their rate base, as well as the

[2] Calculated assuming 290,362 rate-paying Pepco retail customers and an interconnection cost of $0.16 per watt of solar. Assumes the high bound of 300 MW of total required CREF Capacity under Solar for All

support of DOEE and the City Council to alter the D.C. Municipal Regulations for Small Generator Interconnection Rules and CREF Interconnection Standards.

Equity

This alternative achieves **low-moderate equity** for the stakeholders targeted. Since developers are no longer required to pay for interconnections of CREFs, the "free-rider" issue discussed above is ameliorated due to Pepco's assumption of the interconnection costs. The overall rate base internalizes the costs of interconnection, which flags immediate equity concerns, but the additional costs incurred by the ate base are distributed across the entire customer population. Therefore, high-income rate-payers and LMI rate-payers who do not subscribe to a CREF facility would pay an additional cost of $0.60 per MW of new CREF solar development on their utility bill. As discussed above, the proportion of LMI rate-payers impacted is expected to decrease as more CREFs are developed to target LMI residents under the city's Solar for All program. In addition, all city residents benefit from increased adoption of solar energy in the District, as well as grid developments and modernization resulting from CREF interconnections.

ALTERNATIVE II: ALTER TECHNICAL INTERCONNECTION REQUIREMENTS FOR CREFS

Alter the interconnection standards so that certain CREFs operate as Net Energy Metering (NEM) generators with behind-the-meter energy use and calculations of CREF credits. This alternative eliminates the need for interconnection by enabling CREFs to use behind-the-meter energy use, on a case-by-case basis. While interconnection fees are an impediment to distributed solar development, the unique model of community solar provides an opportunity for developers and utilities to work together with city policymakers, investigating alternative smart-meter technology. There is potential for behind-the-meter distributed generation solar arrangements that do not require energy to be distributed to the grid. The utility requires that no more than 5% of the maximum building load can come from direct kW hours of on-site solar electricity. The majority of CREF developments operate under this limit. Advancing the metering technology and altering the flow of energy would circumvent the requirement of these specific CREFs to interconnect to the grid.

For example, in one recent CREF development of an 85-kW system atop a ten-story building on I Street, NW Washington, D.C., there is potential for the grid to not be interconnected to and the energy to be used behind-the-meter. As the inverter converts direct current (DC) electricity to alternating currents (AC) on site, the energy can be used directly within the building itself. A smart meter will read the amount of AC electricity generated before it is transferred to the building (or into the electricity grid, as it would be in the status quo scenario). In addition, the building's master meter will read the total utility grid load minus the solar energy produced at the rooftop array. Both meters are equipped to send data along to the utility and Solar for All grantees. This way, Pepco can calculate the net metering credits and subsidize utility bills of LMI residents in the same way as current CREFs do. The REC and SREC values will be calculated based on the reduction in load of the host building on I Street.

For a project of 85 kWh, the peak load or electricity generation is enough to power a typical energy demand for 8.5 hours. Since the host building on I Street is ten stories, and requires peak electricity load for at least 9 hours per day, the rooftop solar generated energy is assumed to be less than one tenth of the total daily load. Further electrical analysis is necessary, but it is assumed with high confidence that using the CREF electricity on-site, without utility interconnection, would not violate the utility requirement that no more than 5% of the maximum building load can come from direct kW hours of on-site solar electricity. This alternative would only be applicable for CREFs that operate under this 5% maximum building load.

This process does not require interconnection to the utility grid but it does require buy-in from the utility itself, as electricity would not be managed, bought, or sold by Pepco, thereby limiting its engagement in the process. Aside from buy-in from the utility, this alternative requires an alteration to the current Community Renewable Energy Amendment Act of 2013 (CREA), adding language specific to CREFs which elect to utilize this interconnection-free process of electricity generation.

Alternative II: Analysis

Effectiveness

This alternative generates **moderate effectiveness** at achieving the Solar for All program goals, compared to the status quo because it only applies to CREF projects on a case by case basis. For projects that produce over the 5% maximum building load, standard interconnection to the grid is still required – triggering the same barriers to development and Solar for All implementation issues discussed above. The effectiveness of this alternative hinges on the assumption that the majority of CREF developments are sized such that they will produce no more than 5% of the maximum building load (since a considerable amount of CREF rooftop projects are developed on high-load office buildings located on the city's network grid. Additionally, it is assumed that the passage of this interconnection policy change would induce more CREF project developers to structure future projects so that they satisfy this maximum load limit and can operate behind-the-meter, saving development costs and targeting more solar benefits to LMI beneficiaries.

Cost

This is a **moderate cost** alternative as the policy change only applies to qualifying CREFs under the 5% maximum building load. Standard interconnection costs and time management costs apply to CREFs operating over this load limit. If interconnection is not required, behind-the-meter energy use generates a moderate degree of costs for the project developer. Smart meter technology and meter upgrades are required. The costs of CREF development for NEM qualifying behind-the-meter developments require smart meter upgrades costing approximately $50 per 1 kW system.

Compared to $160 per 1 kW on average for standard interconnection, the costs to developers are reduced moderately with this policy change. In addition, interconnection to the grid often instigates distribution system upgrades, borne by the developer. According to Pepco, underground distribution system upgrades average $160 per kW of program size and overhead distribution system upgrades average $45 per kW. The discounted total estimate of costs for qualifying CREFs operating as NEMs equals approximately **$2,807,181**. The discounted total estimate of benefits for qualifying CREFs operating as NEMs equals approximately **$16,322,063.** The cost-benefit ratio equals **0.17**.

Political Feasibility

The political feasibility of this alternative is **low** considering the rules for CREFs written into the Community Renewable Energy Act dictate that they must be interconnected to the utility grid. Under the act, CREFs are a separate category from NEM facilities that operate behind the meter. Because of the current regulations, this alternative is evaluated to have unlikely political support.

Equity

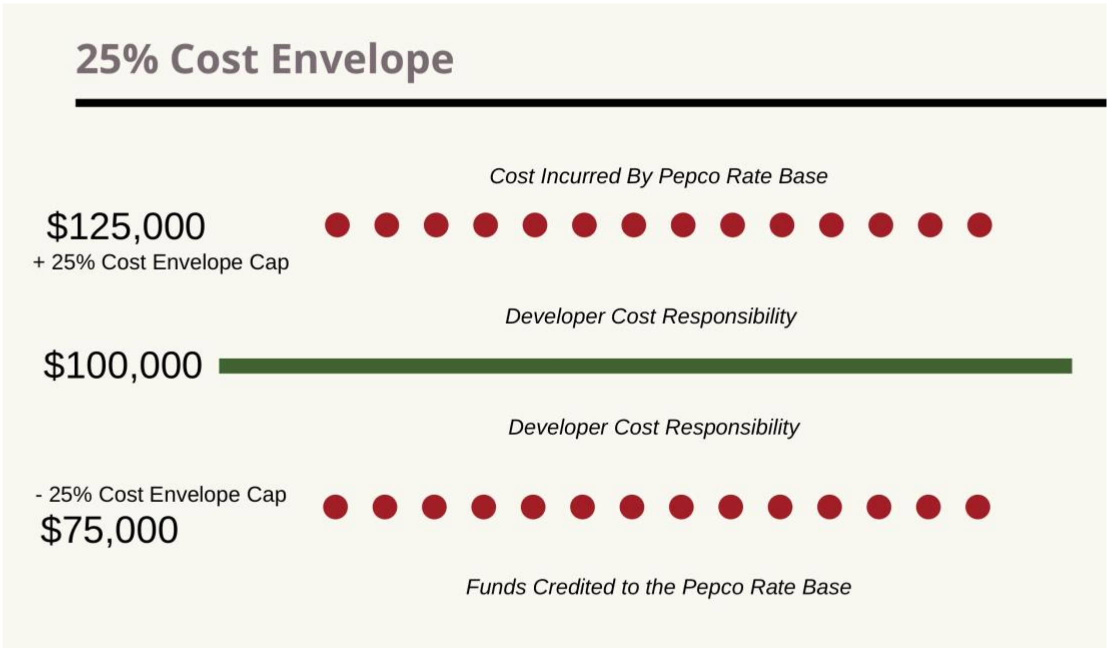
This alternative is evaluated to have **high equity** for parties involved. It does not present new equity concerns for the rate base or Solar for All grantees and beneficiaries. In addition, building occupants in qualifying CREF developments would benefit from knowing their building utilized on-site solar energy.

ALTERNATIVE III. SOLAR INTERCONNECTION AGREEMENT (SIA) FOR PROCESS IMPROVEMENTS

The Solar Interconnection Agreement (SIA) addendum to Solar For All is a two-pronged implementation plan for interconnection process improvements, modeled after New York state's pilot interconnection plan. The SIA comprises a 25% cost certainty envelope and publication of historical and future CREF interconnection location, size, and cost data. Interconnection to the utility grid presents barriers to community solar development beyond the costly fees. This alternative suggests to maintain the current responsibility structure for interconnection fees and payments, while modifying the process for transparency, information clarity, and process predictability.

A cost envelope limits developer cost responsibility to a certain percentage above Pepco's initial cost estimate for interconnection studies and upgrades. If the actual costs of system upgrades exceed the 25 percent envelope utilities will incur those additional costs and can seek to recover the costs from their rate base. The utility internalizes the real interconnection cost if it is above 125% of the initial estimate. Pepco can only recover these additional costs from their rate base – beyond their original estimate – if they can demonstrate a reasonable rationale for their inaccuracy to the Public Utilities Commission. If the costs are less than 75 percent of the original estimate, the utility's rate base will retain the difference after a similar showing of reasonableness, to balance the impact on all ratepayers. The 25% envelope is based off of best practices in California, Utah, Oregon, and a pilot program in New York state. In California, since the implementation of the cost envelope, only once interconnection case has been above the 125% cap and internalized by the utility (Bird, 2018).

Figure 7: 25% Cost Certainty Envelope



Historical and future per unit interconnection costs will be aggregated and published annually by Pepco. Readily available guides offer customers a list of standard prices for typical interconnection facilities and equipment. Unit cost guides published in California have proven to help customers understand and predict the costs of connecting their projects to the grid well before they initiate the application process. The guides can also help to promote cost consistency across projects. A utility is not bound to the upgrade costs in the unit cost guide; it is designed to improve transparency. Historical interconnection costs will also aid in informing developers where the utility has already interconnected a CREF to the grid and provide insight on grid modernization requirements.

Alternative III: Analysis

Effectiveness

This alternative generates **moderate-high effectiveness** at achieving the Solar for All program goals. Increasing the transparency and improving the cost certainty of initial interconnection fee estimates offers valuable insurance to developers. With the cost certainty that a 25% cost envelope provides, developers are able to plan the interconnection costs into their Solar for All grant applications, as well as develop appropriate finance structures and solar payoff timelines. This policy alternative addresses the considerable fluctuations in cost estimates that Solar for All grantees reported to DOEE as a barrier to development. Removing this barrier through a 25% cost certainty envelope will incentivize continued CREF development. Cost to the developer still remains a financial concern, however, the developers will be better equipped to plan these costs into their program finance structure.

Cost

This alternative is a **low-cost** alternative as the only new costs imposed are the administrative costs associated with publishing historical and future interconnection cost guidelines. Pepco may incur additional costs in conducting more thorough cost estimate studies of proposed CREF developments, since they have incentive to provide the most accurate cost estimates as possible. The CREF developer will save costs in program development if the interconnection cost is above 125% of the initial interconnection estimate. These auxiliary costs will be internalized by Pepco and borne by the rate base. It is estimated that a smaller proportion of fees will be added to the rate base than Alternative 1, as the results from California's Rule 21 cost envelope shows that the majority of projects do not outstep the 25% envelope cap.

Political Feasibility

This alternative has **high political feasibility** as it will obtain likely support from stakeholders and engaged policymakers. Since Pepco and CREF interests must be balanced in a policy solution to interconnection issues, this alternative is a thorough solution to major concerns from both parties. Implementing this policy alternative as a pilot component of the DOEE's Solar for All program allows the time for continual cost and impact analysis and the flexibility for program improvements. There are no political drawbacks to publishing historical interconnection data. While this alternative does not eliminate CREF developers' responsibility for interconnection fees, it addresses the lack of insurance and lack of transparency in the interconnection process.

Equity

This alternative has **high equity** and does not produce substantial concerns. Increasing information availability and transparency improve equity for all stakeholders involved. The utility is held to a financial insurance mechanism to promote cost certainty. The rate base will internalize a very small degree of costs, only after the utility substantially proves that the interconnection costs were reasonably higher than 125% of the initial estimates. If the costs do increase beyond the initial standpoint, it is likely that extreme distribution upgrades are needed – which adds public value to the city of Washington, D.C.

OUTCOMES MATRIX

POLICY	EFFECTIVENESS	COST	POLITICAL FEASIBILITY	EQUITY
I. Shift the burden of responsibility	**High:** SfA goals fully reached and subscriber benefits increased	**Moderate cost** **$0.60** per 1 MW to each Pepco's ratepayer. Total NPV of costs: **$15,321,505 to $19,801,488**[3] Low cost to developers and utility	**Low-medium:** No preventative rules but unlikely support from utility	**Low-medium:** Rate payers assume the burden
II. Alter interconnection requirements	**Medium:** Increases effectiveness only for qualifying CREFS	**Low cost** Total NPV Cost: **$2,807,181** Total NPV Benefits: **$16,322,063** Cost Benefit Ratio: **0.17** Total cost borne by CREF developers	**Low:** Behind-the-meter install is against current regulations for CREFs in the CREA.	**High:** Utility, developers, and ratepayers benefit
III. Improve process clarity through SIA pilot	**High-medium:** Transparency incentivizes development	**Low-cost** Full cost estimate requires implementation of pilot program. Cost and benefits shared between developers and utility/rate base.	**High:** Proven success in other jurisdictions. R9 working group established	**High:** Utility, developers, and ratepayers benefit

Given the projected outcomes of each policy option, it is recommended that NPCS pursue Alternative III and advocate for the Solar Interconnection Agreement of a 25% cost curve and published historical and unit cost guides.

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[3] NPV of costs to rate base depends on development schedule. Estimated by dividing total capacity required over entire program years or a 10-year up front development schedule.

RECOMMENDATION

It is recommended that New Partners Community Solar advocate for increased transparency and cost-certainty of CREF interconnection through the utility and public service commission's adoption of **Alternative III: Solar Interconnection Agreement**. This alternative has the highest political feasibility, as well as a low cost to developers and utility. The equity of this alternative ranks highest among the three options because it prioritizes transparency and information sharing, as well as reducing the spillover impacts to non-CREF-subscriber ratepayers. The estimate of increased utility-credit benefit to LMI subscribers is inconclusive due to lack of predictive power, but continuous monitoring throughout the pilot's process will inform the Public Service Commission on the alternatives tangible benefits to CREF developers, rate payers, and LMI beneficiaries.

Alternative I is not recommended on the basis of equity concerns. The overall rate base will be negatively impacted from implementing a fee shifting policy, therefore reducing the effectiveness criterion and the political feasibility of this alternative. The potential for cost-shifting from solar to non-solar customers is one of the most important issues facing utilities and regulators. It should be analyzed as concretely and comprehensively as possible. The cost-benefit analysis methodology used and expanded upon in Appendix C generally ignores distributional impacts, focusing instead on maximizing total net benefits so that, in theory, any losers could be compensated and made no worse off than they were before. Although cost-benefit analyses can be made to incorporate "distributional weights" to account for equity concerns, this is difficult to do and rarely done in practice. A rate and bill impact analysis or Ratepayer Impact Measure Test (RIM Test) conducted by the utility would offer a means of assessing distributional impacts in a manner that is more transparent, comprehensive, and theoretically sound than the traditional application of the cost benefit analysis. Further study on the distributional impacts of Alternative 1, conducted with Pepco's engagement is recommended prior to advocating for, or implementing, such a solution.

Alternative II is also not recommended because of the political feasibility tradeoffs. It is written into the Community Renewable Energy Act of 2013 that CREFs do not operate as NEMs with behind-the-meter on site energy use. However, this alternative has a low cost-to-benefit ratio and promotes high equity and effectiveness. If, in the long term, there is likely political feasibility of passing this alternative, then further discussion of the efficacy of this policy option is recommended.

Considerations

Further policy analysis and working-group conversation between stakeholders is required to evaluate which criteria are most highly weighted by decision makers. The cost-equity tradeoffs are most important to consider when an alternative might impose fee increases on the entire, non-CREF subscribed rate base. It is important to consider the equity of policy changes to ensure any alteration to the current interconnection rules do not reduce the aggregate benefit to society and LMI solar energy beneficiaries. The value of this Solar Interconnection Agreement cost envelope is the increased transparency and cost certainty for CREF developers. Total benefits stemming from this policy change, as well as the costs and benefits of other alternatives, are calculated based on the limited interconnection cost data available from Pepco.

Implementation

Implementing this Solar Interconnection Agreement as a pilot program add-on to the Solar for All program gives it the flexibility to work with the wider community energy policy landscape in Washington, D.C. The pilot program can draw upon some of the assets and relationships that already exist within the Solar for All network, including the current DOEE Solar for All task groups, the aforementioned R9 Public Service Commission working group, and the engagement of Pepco's Green Power Connection team. CREF developers and Solar for All Grantees have a unique position as implementers and advocates of an efficient and cost-equitable interconnection solution. In this position, it is important that New Partners Community Solar and other Solar for All grantees undertake a multifaceted implementation plan of advocacy through attending planning meetings and communicating the program benefits to subscribers and policymakers.

Common themes regarding implementing successful interconnection policies and are worth noting:

- **Proximity to implementers:** Bringing the public into renewable energy policymaking is important, but once implementation begins the Public Service Commission needs to keep strong links with where change is happening to understand how the Solar Interconnection Agreement is functioning with continued CREF development. It is important that Pepco, Solar for All Grantees, and the DOEE have continued engagement with the process.
- **Focused scope:** Continuity is essential for effective implementation. Long time-spans introduce significant risk to achieving policy goals. The proposed pilot Solar Interconnection Agreement is limited to the implementation period of Solar for All so that its efficacy and value can be evaluated at program completion. It is important to pilot such an agreement prior to full adoption so that its risks and benefits are operationalized.
- **Monitoring and evaluation to measure progress:** Program outputs and outcomes play a crucial role in setting and evaluating milestones. This Solar Interconnection Agreement aims to improve the outcomes of Solar for All, as well as illustrate best practices for urban community energy and distributed solar interconnection. Continued monitoring and evaluation of the program's efficacy is necessary to serve as an exemplar case of interconnection improvements for the greater U.S. interconnection policy field.
- **Distributional impacts and emergency power restoration:** Waiving interconnection fees for CREFs supporting the public good and emergency assistance is a consideration moving forward. For example, Pepco recently funded an emergency battery storage system at the Maycroft affordable housing property Washington, D.C. The solar-plus-storage system provides three days of power to residents in the event of an extended power interruption from severe weather or other emergencies (Harper, 2018). The target beneficiaries of CREFs under Solar for All may shift the valuation of distributional impacts. Therefore, it is important to consider altering interconnection costs and fees on a case-by-case basis, depending on public goodwill.

APPENDICES

Appendix A

SREC Market Requirements

DC SREC market requirements as currently set by state legislation:

Energy Year	% Solar Requirement	SACP
2019	1.85%	$500
2020	2.18%	$500
2021	2.50%	$500
2022	2.60%	$500
2023	2.85%	$500
2024	3.15%	$400
2025	3.45%	$400
2026	3.75%	$400
2027	4.10%	$400
2028	4.50%	$400
2029	4.75%	$300
2030	5.00%	$300
2031	5.25%	$300
2032	5.50%	$300
2033	6.00%	$300
2034	6.50%	$300
2035	7.00%	$300
2036	7.50%	$300
2037	8.00%	$300
2038	8.50%	$300
2039	9.00%	$300
2040	9.50%	$300
2041	10.00%	$300

Source: EIA Report "Retail Sales of Electricity by State by Sector by Provider (EIA-861)

Appendix B

Pepco Customer Base 2012-2016

POTOMAC ELECTRIC POWER COMPANY

Retail Customers at Year-End

2012 - 2016

	2016	2015	2014	2013	2012
System					
1. Residential	782,130	767,392	740,102	726,924	719,701
2. Commercial	75,834	74,814	74,825	73,937	73,342
3. Other	132	129	124	127	132
Retail Customers	858,096	842,335	815,051	800,988	793,175

	2016	2015	2014	2013	2012
District of Columbia					
1. Residential	264,300	256,316	244,550	237,973	233,642
2. Commercial	26,033	25,876	26,581	26,378	26,282
3. Other	29	28	31	33	34
Retail Customers	290,362	282,220	271,162	264,384	259,958

	2016	2015	2014	2013	2012
Maryland					
1. Residential	517,830	511,076	495,552	488,951	486,059
2. Commercial	49,801	48,938	48,244	47,559	47,060
3. Other	103	101	93	94	98
Retail Customers	567,734	560,115	543,889	536,604	533,217

Source: Pepco Holdings. Retail Customers at Year-End 2012 – 2016. Published 2016.

Appendix C
Cost Analysis

This appendix, along with the cost spreadsheet available at https://tinyurl.com/RitaClifftonAPP, provides a detailed breakdown of the cost-benefit analysis, assumptions, and sensitivities.

Baseline
The baseline that all policy options are measured against is the status quo scenario of CREF developers paying for all interconnection fees and costs.

Time Horizon and Discount Rate
This analysis is conducted over a 13-year time horizon, until the Solar for All program conclusion in 2032. All costs are calculated at year-end and with a 7 percent discount rate.

Discussion on Cost-shifting
Cost-shifting from distributed solar customers to non-solar customers occurs in the form of rate impacts, which result in higher bills for non-solar customers. Rates increase or decrease to reflect changes in electricity sales levels, changes in costs, or both. A comprehensive, long-term rate impact analysis accounts for these effects, thereby providing the necessary information to help understand this critical issue. A rate impact analysis conducted by the utility will fully capture distributional impacts of cost-shifting. A cost-benefit analysis or value of solar analysis has limited applicability to addressing long-term distributional costs.

Where applicable, the costs are separated into costs to the utility, costs to the CREF developers, and costs that the utility must internalize into the rate base which are then borne by the ratepayers.

General Assumptions
The "Assumptions" tab lists all of the general assumptions, as well as each option's assumptions and numbers used for calculations. Changing values on this tab will change the cost-benefit analysis results accordingly. The key general assumptions, and their justification, are as follows:

SREC Value in Washington D.C. (as of 2019)	$470	Market research from SRECTrades.com
Total number of retail customers in rate base	290,362	Pepco Rate Analysis (2016)
Size range of CREF facility	up to 5MW	CREF Standards
Solar for All total capacity required by 2032	240 to 300 MW Analysis uses the upper bound of 300 MW based on projected scale of SfA.	Solar for All implementation plan estimate

Solar for All FY 2017 - FY 2019 Program Goals (capacity in MW)	60 MW	Solar for All 2017 Annual Report
Current Solar for All implementation (capacity in MW as of 2019)	10 MW	Solar for All 2017 Annual Report

Alternative I: Fee Internalized into Rate Base

The "Fee Internalized into Rate Base" tab provides a cost analysis of the distribution of CREF interconnection costs across the rate base. It analyzes the distribution of costs for two scenarios: dividing the required MW solar capacity equally across all program years *or* a ten-year upfront development of all MW solar capacity. Both scenarios start in 2020, assuming the program change is implemented in year 1. Option-specific assumptions and values include:

Interconnection Cost Per watt, for commercial rooftop PV arrays	\$0.11 - \$0.16 (analysis uses the upper bound of \$0.16 based on D.C.'s interconnection standards, permitting fees, and wage rates)	NREL Study (2017) calculating interconnection costs. Includes assumed building permitting fee of \$400 and six office staff hours for permitting and interconnection application preparation and submission
Scenario 1 Total Capacity divided across all program years	30	Based on upper bound of SfA implementation plan
Scenario 2 10-year upfront development: Total Capacity per year	23.1	Based on upper bound of SfA implementation plan

Rate increases due to interconnection fees are calculated per year as follows:

$$\text{Fee per ratepayer} = \frac{(\textit{Interconnection Cost Per watt } X\ 100{,}000)\ X\ (\textit{Annual MW development based on Scenario})\ X\ (1+\textit{Pepco's Rate of Return})}{\textit{Number of Pepco Retail Customers}}$$

Scenario 1

$$\text{Fee per ratepayer} = \frac{(0.16 \text{ X } 100{,}000) \text{ X } (23.1)\ X\ (1+.0745)}{290{,}362}$$

The discounted total estimate of additional rate fees per retail customer over the thirteen-year Solar for All period equals approximately **\$53**. The discounted total estimate of additional rate fees for the entire rate base over the thirteen-year Solar for All period equals approximately **\$15,321,505**.

Scenario 2

$$\text{Fee per ratepayer} = \frac{(0.16 \text{ X } 100{,}000) \text{ X } (30) \text{ X } (1+.0745)}{290{,}362}$$

The discounted total estimate of additional rate fees per retail customer over the thirteen-year Solar for All period with upfront development equals approximately $68. The discounted total estimate of additional rate fees for the entire rate base over the thirteen-year Solar for All period with upfront development equals approximately **$19,801,488**.

Alternative II: Alter Technical Requirement – Behind-the-Meter

The "Behind-the-meter" tab provides a cost-benefit analysis of the policy change to allow qualifying CREFs to operate as NEM with on-site, behind-the-meter energy use. Option-specific assumptions and values include:

Marginal costs of smart inverter upgrades for a 1 kW on site solar system	$50	Retrieved from article by T&D world (Niggli, 2013)
Meter reading software (annual fee)	$20	Market research
Average cost for underground distribution system upgrades (per 1 kW system)	$160	Sourced from Pepco estimates for projects that went through. Assuming 3/4 projects are underground based on grid map of Washington D.C.
Average cost for overhead distribution system upgrades (per 1 kW system)	$44.74	Sourced from Pepco estimates for projects that went through. Assuming 3/4 projects are underground based on grid map of Washington D.C.
Estimated percentage CERFs qualifying as NEM facilities	50%	Estimated proportion of qualifying CERFs - alter with program assumptions

Total costs of operating as a NEM are calculated as follows:

$$\text{Costs} = \frac{(\textit{Total Smart Inverter Upgrades}) \text{ X } (\textit{Annual MW development X Estimated Percentage of Qualifying CREFS})}{\textit{Number of program years}}$$
$$+ \frac{(\textit{Cost of Meter Reading Software}) \text{ X } (\textit{Annual MW development X Estimated Percentage of Qualifying CREFS})}{\textit{Number of program years}}$$

$$\text{Costs} = \frac{(50{,}000) \text{ X } (300 \text{ X } .5)}{13} + \frac{(20) \text{ X } (300 \text{ X } .5)}{13}$$

The discounted total estimate of costs for qualifying CREFs operating as NEMs equals approximately **$2,807,181**.

Total benefits (costs saved) of operating as a NEM are calculated as follows:

$$\text{Benefits} = \frac{\begin{gathered}[\ (\%\ underground\ systems\ X\ average\ cost\ for\ underground\ distribution\ system\ upgrades) + \\ (\%\ overhead\ systems\ X\ average\ cost\ for\ overhead\ distribution\ system\ upgrades)\ ]X \\ (Annual\ MW\ development\ X\ Estimated\ Percentage\ of\ Qualifying\ CREFS)\end{gathered}}{Number\ of\ program\ years}$$

$$+\ \frac{(Interconnection\ fee\ per\ MW\ developed)\ X\ (Annual\ MW\ development\ X\ Estimated\ Percentage\ of\ Qualifying\ CREFS)}{Number\ of\ program\ years}$$

$$\text{Benefits} = \frac{\begin{gathered}[(.75\ \mathrm{X}\ 160) + (.25\ \mathrm{X}\ 44.74)]\ \mathrm{X} \\ 300 * .5\end{gathered}}{13} + \frac{(160\ \mathrm{x}\ 1000)\ \mathrm{X}\ (300\ \mathrm{X}\ .5)}{13}$$

The discounted total estimate of benefits for qualifying CREFs operating as NEMs equals approximately **$16,322,063.**

The cost-benefit ratio – the NPV of Total Costs divided by the NPV of Total Benefits – is equal to **0.17** for this alternative, operating under the aforementioned assumptions.

Alternative III: Solar Interconnection Agreement

The Cost Envelope option cannot be priced under the aforementioned methodology of cost benefit analysis or distributional ratepayer impacts, because the distributive outcomes of the measure depend wholly on how many CREF developments are undertaken and of these, how many interconnection process costs are above the 125% initial cost estimate. This alternative is recommended as a pilot program in order to collect data and gather information on CREF development under the Solar Interconnection Agreement. This data will inform cost analyses in order to rank the costs against the baseline status quo costs.

Sensitivities and Crossover Analysis

This alternative will represent a lower cost to the overall rate base than both Alternative 1 and Alternative 2. The costs of this Solar Interconnection Agreement will not outweigh the other policy alternatives unless over 50% of future CREF developments justifiably violate the 25% cost envelope. In this case, the utility is required to internalize the interconnection costs and the rate payers would face higher utility fees. These fees would be calculated similar to Alternative 1's rate increase analysis.

Costs for the publication of historic and future interconnection fees are assumed to be minimal, based on research and analysis of California's Rule 21 for interconnection processes.

Sensitivity Analysis

Firstly, several policy options considered are new programs and unique to community solar. Thus, several of the measurements of program capacity development and metering and interconnection fees are approximate estimates from the literature and past rate studies. Therefore, estimates are not valid predictors of exact costs and impacts. Since the assumptions are standardized across the policy alternatives, the analysis does provide a reliable method of ranking policies against each other and comparing distributive costs.

The discount rate of 7% was used as it is standard practice in cost-benefit analysis. While previous value of solar studies in Washington, D.C. used a discount rate of 3%[4], it was deemed appropriate to use the standard 7% rate as it is closer to Pepco's rate of return of 7.45%.

There is uncertainty regarding the total required MW capacity of CREF development under Solar for All due. The literature suggests that Solar for All will require 240 to 300 MW of development by 2032. This analysis used the higher bound to ensure that cost analysis was balanced with stakeholder equity in decision-making. Additionally, there is uncertainty regarding the phasing of CREF development across years – either spread equally or with more upfront development. Alternative 1's analysis examines both these scenarios and concludes that, while an equal distribution of program development across all years provides the lowest cost, both scenarios are relatively close in NPV of total costs.

Please see the cost spreadsheet, available for download at **https://tinyurl.com/RitaClifftonAPP**

[4] Office of the People's Council (OPC), Synapse Energy, *Distributed Solar in the District of Columbia*. Value of Solar Study. 12 April 2017

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