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GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

KARL A. RACINE
ATTORNEY GENERAL

Public Interest Division
Public Integrity Section

E-Filed

November 9, 2018

Ms. Brinda Westbrook-Sedgwick, Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite # 800
Washington, DC 20005

Re: Formal Case No. 1017 – In the Matter of the Development and Designation of Standard Offer Service in the District of Columbia

Dear Ms. Westbrook-Sedgwick:

Enclosed, please find the Comments of the Department of Energy and Environment on Behalf of the District of Columbia Government. If you have any questions regarding this filing, please do not hesitate to contact the undersigned.

Sincerely,

KARL A. RACINE
Attorney General

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

FORMAL CASE NO. 1017, IN THE MATTER OF THE DEVELOPMENT AND DESIGNATION OF STANDARD OFFER SERVICE IN THE DISTRICT OF COLUMBIA; THE 2018 BIENNIAL REVIEW OF THE STANDARD OFFER SERVICE

Comments by the Department of Energy and Environment
On Behalf of the District of Columbia Government

November 9, 2018

INTRODUCTION

In its Order No. 19431, the Public Service Commission of the District of Columbia (Commission) initiated the 2018 biennial review of the Standard Offer Service (SOS), and posed a series of questions regarding the SOS.[1] On behalf of the District of Columbia Government, the Department of Energy and Environment (DOEE) hereby provides limited comments regarding the use of renewable power purchase agreements (PPAs) as a component of SOS.

BACKGROUND

DOEE has been exploring ways in which the District of Columbia can increase the use of renewable energy to achieve the clean energy goals set forth in the Sustainable DC Plan and Clean Energy DC. Specifically, Clean Energy DC has a recommended action, CRE 2, of providing the SOS through aggregated renewable energy PPAs. Clean Energy DC notes that aggregated renewable energy PPAs may reduce electricity rates below those of the current SOS, but that long-term energy procurement entails risks, recommending a further analysis on the feasibility of this approach.[2]

[1] Formal Case No. 1017, *rel.* August 9, 2018.
[2] See Clean Energy DC, pp. 141-143.

COMMENTS

In furtherance of the Clean Energy DC recommendation, DOEE commissioned a preliminary independent study (Study), by the Center for Renewables Integration, regarding the feasibility of using of long-term PPAs for SOS. The Study is attached hereto as "Appendix A." The Study found that entering into long term PPAs with renewable energy generators is feasible.

However, beyond this Study, more deliberation and further analysis is required before DOEE can formulate its policy position on this subject. For example, DOEE has concerns about a lack of flexibility inherent in long-term PPAs. Based on DOEE's internal consideration, input from stakeholders, and testimony before Council on the Clean Energy Omnibus bill, DOEE has concluded that there must be flexibility in the SOS procurement program. Reduced flexibility has the potential to impact an SOS Administrator's ability to manage cost and risk, potentially resulting in higher costs for ratepayers.

None of this is to say that requiring long-term renewable energy PPAs for SOS does not also have advantages, particularly where there is a stable customer base such as exists in the District of Columbia.[3] However, DOEE's position at this time is that further analysis is needed before the Commission should make any change to the current SOS program such as shifting to long term renewable generation PPAs for SOS.

[3] It should also be noted that DOEE does not believe that clean energy SOS PPAs constitute an out-of-market financial subsidy to renewable energy generation facility owners that sell wholesale electricity supply services in PJM's markets. *See,* Order No. 19431, ¶ 11. The recent Federal Energy Regulatory Commission order addressing the issue of out-of-market state subsidies, applies to the interstate *capacity* market, which is separate from the *power* market. *Calpine v. PJM,* Docket EL16-49-000, *rel.* June 29, 2018. [*Calpine*]. PPAs are not a "subsidy", as they involve arm's length negotiation in the competitive market. Moreover, PPAs are not "made or directed by a state" and so are not the type of out-of-market payment that is the subject of *Calpine*. If the stability in demand from a PPA provides a renewable energy supplier with the ability to bid excess supply into the capacity market at a price lower than what they could otherwise offer, this is no more of a "subsidy" or "out-of-market payment" than any state measure which has a positive effect on a capacity owner's cost of doing business such as lower tax rates, better health care costs, state-funded university management programs, etc.

ATTACHMENT A

FINAL REPORT

September 28, 2018

FEASIBILITY STUDY

INCREASING THE RENEWABLE ENERGY CONTENT
OF
STANDARD OFFER SERVICE

prepared for

District of Columbia Department of Energy & Environment

by

Center for Renewables Integration
Harry Warren, Principal Investigator

Center for
Renewables
Integration

ABSTRACT

This study examines the feasibility of increasing the renewable energy content of the District of Columbia's Standard Offer Service (SOS) by entering into long-term Power Purchase Agreements (PPAs) with renewable energy generating facilities, while maintaining and potentially lowering SOS prices. Availability and pricing of renewable generation sources are reviewed, and indicators of future availability and price trends are presented. Procurement scenarios are developed based on renewable projects currently under development, and the potential effects on future SOS prices are modeled. Revisions to the current SOS procurement process needed to incorporate PPAs are described, and the implications of the new process for price stability are analyzed. The study's appendices contain information on renewable energy procurement in other jurisdictions, renewable energy sourcing alternatives, study modeling details, current District of Columbia SOS procurement law and regulations, and other background information.

The study finds that new wind and solar projects under development today within PJM states provide an ample selection of projects to meet SOS purchasing objectives, and fixed-price PPAs are available today at prices competitive with, and in some cases lower than, conventional power. This implies that the objectives of higher renewable energy content at comparable or lower prices can be met. Incorporating PPAs into SOS will require revision of the current SOS purchasing structure, moving away from Full Requirement Service (FRS). A structure based on PPAs can achieve near-term price stability comparable to FRS and provide long-term price stability. A transition to the new SOS procurement model could be accomplished within a three to five-year period, allowing for the roll-off of current FRS contracts, securing new PPAs, and establishing new electricity purchasing parameters. New renewable energy supplies could begin to flow by 2022.

EXECUTIVE SUMMARY

The Clean Energy DC climate and energy plan, published in October 2016, "is DOEE's proposal to reduce greenhouse gas (GHG) emissions by 50% below 2006 levels by 2032, while increasing renewable energy and reducing energy consumption, as directed by the District's sustainability plan, Sustainable DC." Among its recommendation with respect to energy supply is to, "Replace the current Standard Offer Service (i.e. the supply contracts for customers who do not choose competitive suppliers) with a mix of short-term and long-term contracts, including long-term power purchase agreements that maximize renewable energy to the extent practicable." At the present time, customers purchasing SOS supply account for 30% of the District's total electricity use, comprised of 14% of commercial use and 84% of residential use.

On July 10, 2018, the Clean Energy DC Omnibus Amendment Act of 2018 (B22-0904) was introduced in the District of Columbia City Council. Among the Bill's provisions is a requirement to replace the current SOS with a new program similar to the scenario outlined in the Clean Energy DC plan. On August 9, 2018, the Public Service Commission of the District of Columbia (DCPSC) initiated its biennial review of SOS procurement (see Order 19431 in Formal Case 1017). As part of that review the Commission has asked for comments on a number of issues related to adopting this same strategy.

A review of renewable energy purchasing practices across the nation indicates that adopting an accelerated pace of renewable energy purchasing through long-term PPAs would place the District's SOS procurement in the vanguard of renewable procurement practices.

Recent trends, current market conditions and future projections indicate that a large pool of new wind and solar projects will be available to supply the needs of SOS. Over 75,000 MW of capacity either operating or under development in the region, compares with 1,000 MW to 1,500 MW of combined wind and solar capacity that would be needed to supply D.C. SOS requirements. The U.S. Energy Information Administration (EIA) projects that on a nationwide basis, solar and wind power will continue to provide a substantial fraction of new generating capacity additions in the coming years.

A sample of PPA price offers indicates that a number of new wind and solar projects under development are competitive with current and projected conventional power prices. Projections are for construction costs of new utility-scale solar projects to decline, and to a lesser extent for wind project costs to decline, promising increased competitiveness with conventional power prices and the potential for lower price offers from new solar and wind projects. The expiration and ramp-down of federal tax incentives for new wind and solar projects, however, will put upward pressure on PPA prices that will counter the downward pressure from declining construction costs, efficiency and operational improvements.

To illustrate the potential effects of including long-term PPAs in the SOS purchasing strategy, a number of scenarios have been analyzed:

- Ramp Rate #1 – Reach 70% of SOS requirements in 3 years
- Ramp Rate #2 – Reach 90% of SOS requirements in 6 years
- Ramp Rate #3 – Reach 90% of SOS requirements in 12 years

Ramp Rate #1 is consistent with a scenario modeled in the Clean Energy DC plan, meshes with the roll-off of 3-year supply contracts that are part of the current residential SOS portfolio, and represents the most rapid ramp up of renewable energy purchasing that might reasonably be executed. Ramp Rate #2 represents a slightly more measured purchasing program, but with a higher ultimate target. Ramp Rate #3 represents a much more gradual purchasing program, with the final year of the ramp-up corresponding to the final year of the Clean Energy DC planning horizon.

All scenarios show the opportunity for lower SOS prices in the long term, owing to the expectation that nominal electricity generation prices will rise over time. Importantly, since PPAs are available at prices competitive with power prices today, SOS customers would not be asked to pay more today in return for that long-term benefit.

SOS is currently provided by Pepco, acting as SOS Administrator. Pepco secures the needed electricity supply through Full Requirements Contracts (FRS) with wholesale power suppliers. In the FRS contracts each wholesale supplier provides all needed electricity for a specified percentage of the SOS customer base at a fixed price(s) per kilowatt-hour (kWh).

Each year wholesale bids are solicited to supply various customer groups. Contracts supporting residential and small commercial SOS are for three years, while contracts supporting large commercial service are for only one year. In addition to the wholesale FRS contract prices, Pepco adds certain cost elements to develop the total SOS price including transmission charges billed through PJM, an administrative charge and applicable taxes.

The current SOS structure, which purchases all of the required electricity under FRS contracts, is inconsistent with simultaneously entering into long-term electricity contracts with renewable energy projects. The two overlapping purchases would result in a duplicative supply of electricity, especially as PPA purchases grow over time to match nearly all SOS requirements.

A procurement approach suited to integrating long-term renewable PPAs combines those purchases with the purchase of other necessary wholesale power market services. The District's Department of General Services, in fact, shifted its electricity purchasing strategy in this way after it began to take delivery of wind power through the PPA it signed in 2015.

The current SOS procurement process based on one-year and three-year FRS contracts provides one-year price certainty and, in the case of residential customers, three-year price "smoothing". A shift to a PPA strategy provides long-term cost stability and comparable year-to-year price "smoothing". While the PPA approach does not provide one-year certainty in the cost of SOS supply, prices to SOS customers can be fixed in the near-term with cost overruns or underruns captured through true-up charges in future periods.

While this study has sought to be thorough in presenting and investigating a full range of issues relating to the feasibility of this SOS transition, the path forward requires careful consideration and the PPA strategy will need further validation as it moves toward implementation.

1. Further validation of project availability and pricing should be undertaken. The inventories of projects under development and the sample pricing offers are from reliable sources, but further validation is needed. This could be accomplished through a Request for Information process seeking "indicative offers" to guide the detailed development of PPA procurements.

2. The implications for the role of SOS Administrator should be detailed. The implications of entering into long-term PPA contracts and of managing a revised procurement process are significant for the SOS Administrator and should be fully reviewed. The current biennial review phase of the DCPSC FC1017 Docket is a venue for this review.

3. Additional stakeholder engagement and review of the price stability implications of the new SOS process should be undertaken. This study described a tracking / true-up mechanism for short-term price setting and presents an analysis of year-to-year price stability based on historical PJM hourly pricing data. Management of price stability is of central concern to SOS customers, and further review and validation of this issue is advisable. Note that this further review should explore the ways in which additional prices stability can be achieved by incorporating risk management techniques, beyond the simple strategy presented in this study.

4. Provide oversight bodies with implementation flexibility. It has been noted throughout this report that the electricity market is subject to significant uncertainties over time. Advances in technology, public policy decisions at all levels of government, global energy market and economic conditions, court decisions, etc. could influence the availability of renewable energy supplies, the pricing of those supplies and the conventional energy market. The oversight body(ies) tasked with implementing a new SOS strategy should be granted sufficient flexibility in strategy design, phase in, and approvals to react to future circumstances.

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SECTION 1 – INTRODUCTION

Clean Energy DC

The Clean Energy DC Climate and Energy Action Plan, published in August 2018, "is the District's proposal to reduce greenhouse gas (GHG) emissions at least 50% below 2006 levels by 2032 while increasing renewable energy and reducing energy consumption, as directed by the landmark Sustainable DC plan; and to put us on a path to achieve carbon neutrality by 2050, a goal announced by Mayor Bowser in December 2017."[1]

The plan models a broad set of actions to achieve its goal spanning buildings, energy supply and transportation. Among its recommendations with respect to energy supply is to, "Replace the current Standard Offer Service (i.e. the supply contracts for customers who do not choose competitive suppliers) with a mix of short-term and long-term contracts, including long-term power purchase agreements that maximize renewable energy."[2]

This recommendation supports the GHG reduction goal in two ways:

- by increasing the renewable content of SOS at a pace faster than required by the current RPS, and
- by employing long-term contracts for renewable energy.

DOEE modeled that a revision to SOS procurement could reduce greenhouse gas emissions by 584,000 tons of CO2 relative to a 2032 business-as-usual projection, a 6.6% reduction in the total.[3] This CO2 reduction estimate is based on a scenario in which 70% of SOS requirements are sourced through long-term PPAs with renewable energy projects, phasing in over a three-year period.[4] This ramp rate would push SOS past the District's near-term and long-term RPS requirements.

DOEE believes that long-term PPA contracts "bundling" both electricity supply and Renewable Energy Credits (RECs) can be fully counted toward the District's GHG reduction goals, whereas the purchase of RECs alongside conventional market power purchases may not be counted in the same manner. The combination of contract structure and increased renewable content taken together provide the opportunity to advance the District's GHG reduction goals.

A revision to SOS procurement could reduce greenhouse gas emissions by 584,000 tons of CO2 relative to a 2032 business-as-usual projection, a 6.6% reduction in the total.

[1] Clean Energy DC – The District of Columbia Climate and Energy Plan, Department of Energy & Environment, Government of the District of Columbia, August 2018 p. v
[2] Ibid p. xi
[3] Ibid p. xiv, Table ES1
[4] Ibid p. 28 - 29

The plan notes that in 2015 and 2016 the District government signed PPAs for both wind and solar power to supply part of the electricity needs of government buildings,[5] and that the District expects to realize significant cost savings over the 20-year lifetime of those PPAs. The anticipation that a revised SOS procurement strategy could similarly reduce costs to SOS buyers is also central to the interest in this opportunity.[6]

The plan suggests that, "The District Government needs to conduct further analysis on procurement strategies and contract structures to mitigate risks, maximize long- term benefits, and ensure competitive pricing to maintain an adequate customer base."[7] This study has been commissioned as part of that further analysis.

On July 10, 2018, while this study has been underway, the Clean Energy DC Omnibus Amendment Act of 2018 (B22-0904) was introduced in the District of Columbia City Council. Among the Bill's provisions is a requirement to replace the current SOS with a new program similar to the scenario outlined in the Clean Energy DC plan.

On August 9, 2018, the Public Service Commission of the District of Columbia (DCPSC) initiated its biennial review of SOS procurement (see Order 19431 in Formal Case 1017). As part of that review the Commission has asked for comments on a number of issues related to adopting this same strategy.

Standard Offer Service

SOS supply accounts for 30% of the District's total electricity use, comprised of 14% of commercial use and 84% of residential use.

SOS is a feature of the District's Retail Electric Competition and Consumer Protection Act of 1999, which opened the District's electricity market to competition. Regulations call for Pepco, as the District's Electric Company, to act as the SOS Administrator[8] and to procure the necessary electricity supply through a wholesale procurement process.[9]

At the present time, customers purchasing SOS supply account for 30% of the District's total electricity use, comprised of 14% of commercial use and 84% of residential use.[10] The history and current status of SOS is described in detail in Section 4 of this study.

With respect to its renewable energy content, SOS supply is compliant with the District's RPS requirements. RECs that must be acquired and retired for RPS compliance are included in the wholesale purchase contracts procured by Pepco. Note that the arrangements wholesale suppliers have in place to secure the needed RECs are not known and are not specified as part of

[5] Ibid p. 141
[6] Ibid p. 141
[7] Ibid p. 141 - 142
[8] District of Columbia Municipal Regulations, Chapter 15-4101.1
[9] Ibid Chapter 15-4101.2
[10] Figures from Historical and Analytical Information for Electricity, Status of Electric Competition, DCPSC website https://www.dcpsc.org/Utility-Information/Electric/Historical-and-Analytical-Information-for-Electric.aspx

the SOS procurement bidding requirements. Wholesale suppliers may be procuring the needed RECs from renewable generators through short-term contracts, long-term contracts or bundled power and REC contracts, or from intermediary REC aggregators and brokers who in turn have contracts with generators. A shift to a new SOS purchasing program would provide certainty that renewable energy sourcing is executed in a manner that effectively reduces the District's GHG emissions.

Survey of renewable energy procurement practices

Adopting an accelerated pace of renewable energy purchasing through long-term PPAs would place the District's SOS procurement in the vanguard of renewable procurement practices in the U.S. As detailed in Appendix 1, a survey of SOS procurement practices, other municipal electricity procurements, and corporate, institutional and governmental end use procurements reveals the following:

- Most default service or SOS providers procure renewable energy to meet state RPS standards but are not adding higher renewable energy content beyond those standards. RPS compliance is generally accomplished through REC purchases in the short-term market, the long-term market or both, depending on the jurisdiction.

- Municipal aggregators (including Community Choice Aggregators) typically operate in states with restructured electricity markets, and most were initially formed for the purpose of securing low priced power supplies through large scale purchasing. In some instances, however, including Community Choice Aggregation in California, there is growing focus on higher renewable content. This is often accomplished through REC purchases, though there is movement toward bundling electricity supply with RECs.

- Corporations, institutions, and governments (buying supplies for their own buildings) have long histories of purchasing unbundled RECs to achieve aggressive renewable energy purchasing goals and have been the vanguard of purchasing bundled energy supply and RECs under long-term contracts. The District of Columbia Department of General Services is among these leaders.

> A shift to a new SOS purchasing program would significantly help reduce the District's GHG emissions, and it would place the District in the vanguard of renewable energy purchase practices.

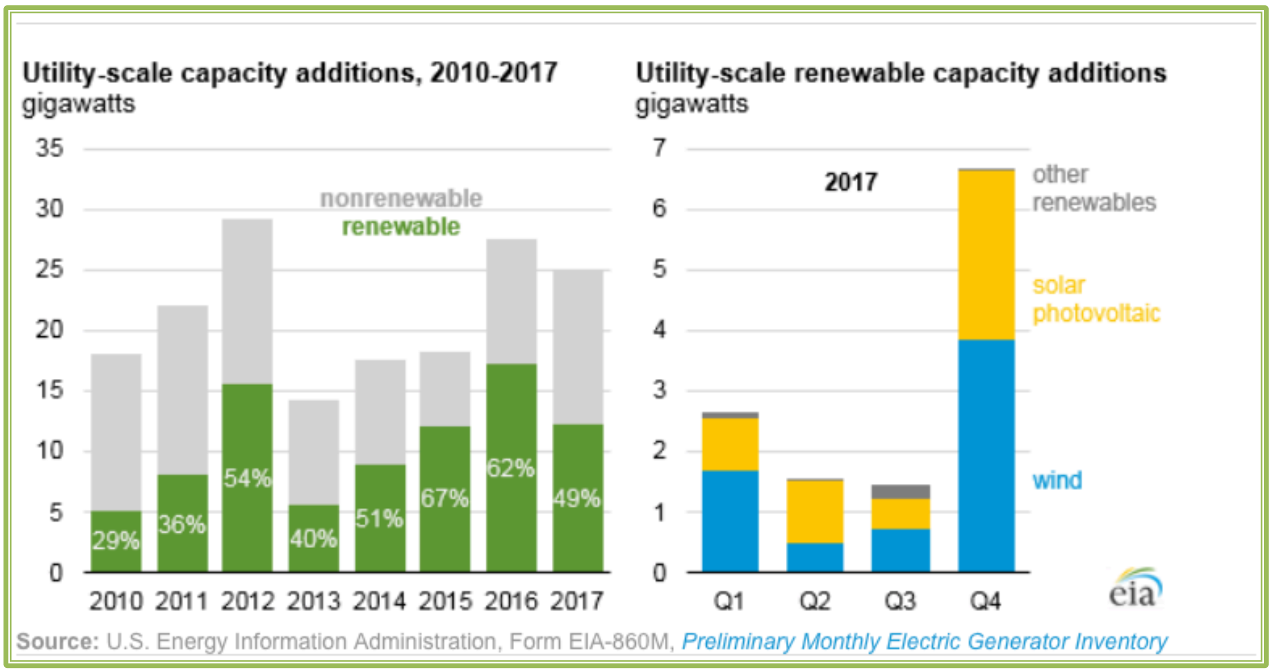
SECTION 2 – RENEWABLE ENERGY AVAILABILITY AND PPA PRICING

Project availability

National trends in renewable energy construction

Electric power generation from renewable energy sources has been increasing rapidly across the U.S. for more than a decade. In the 5-year period spanning 2013 through 2017 more wind and solar generating capacity has been added nationwide than has been added by all other generation sources.

Figure 2.1[11] - Recent National Utility Scale Electric Capacity Additions



[11] Today in Energy, January 10, 2018, U.S. Energy Information Administration

Regional project availability

Table 2.1 summarizes the on-shore[12] wind power capacity either under development or operating within PJM states.[13] Table 2.2 summarizes solar power under development or operating within these states. The over 60,000 MW of new wind and solar capacity under development, supplemented by approximately 15,000 MW of operating capacity compares with 1,000 MW to 1,500 MW of combined wind and solar capacity that would be needed to supply D.C. SOS requirements.

Many wind and solar projects are either under development or operating in the region that could supply SOS requirements.

Table 2.1 – Summary of Regional Wind Capacity[14]

	Under Development	Operating	Total
Delaware	-	-	-
D.C.	-	-	-
Illinois	9,850	4,563	14,413
Indiana	8,096	2,600	10,696
Kentucky	300	-	300
Maryland	-	204	204
Michigan	5,871	2,592	8,463
New Jersey	-	8	8
North Carolina	-	208	208
Ohio	3,279	571	3,850
Pennsylvania	563	1,590	2,153
Tennessee	-	-	-
Virginia	180	-	180
West Virginia	270	771	1,041
TOTAL	**28,410**	**13,105**	**41,515**

At the present time, wind power projects are concentrated in a few states within the region, with nearly 2/3 of new development activity and over half of the operating capacity located in Illinois and Indiana.

[12] Both Delaware and New Jersey currently have off-shore wind power projects under development. These resources are being developed under special state incentive programs and are not considered available for DC SOS PPAs.

[13] As discussed in Appendix 2, the PJM Interconnection region covers all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[14] Data compiled by CRI from PJM and MISO queue data

Regional solar development is less concentrated, but Virginia and North Carolina taken together account for over 30% of all new solar development, and Illinois, Indiana and Ohio combine to account for nearly half. There is little operating solar capacity in the region at this time, and a closer review of the data reveals that the overwhelming majority of operating systems are quite small with only five out of 150 projects producing over 20 MW in capacity.

Table 2.2 – Summary of Regional Solar Capacity[15]

	Under Development	Operating	Total
Delaware	365	-	365
D.C.	-	-	-
Illinois	5,040	9	5,049
Indiana	4,709	27	4,736
Kentucky	975	-	975
Maryland	927	233	1,160
Michigan	3,970	106	4,075
New Jersey	90	595	684
North Carolina	2,114	395	2,509
Ohio	6,123	3	6,126
Pennsylvania	915	18	934
Tennessee	-	-	-
Virginia	8,508	504	9,012
West Virginia	178	-	178
TOTAL	**33,914**	**1,889**	**35,803**

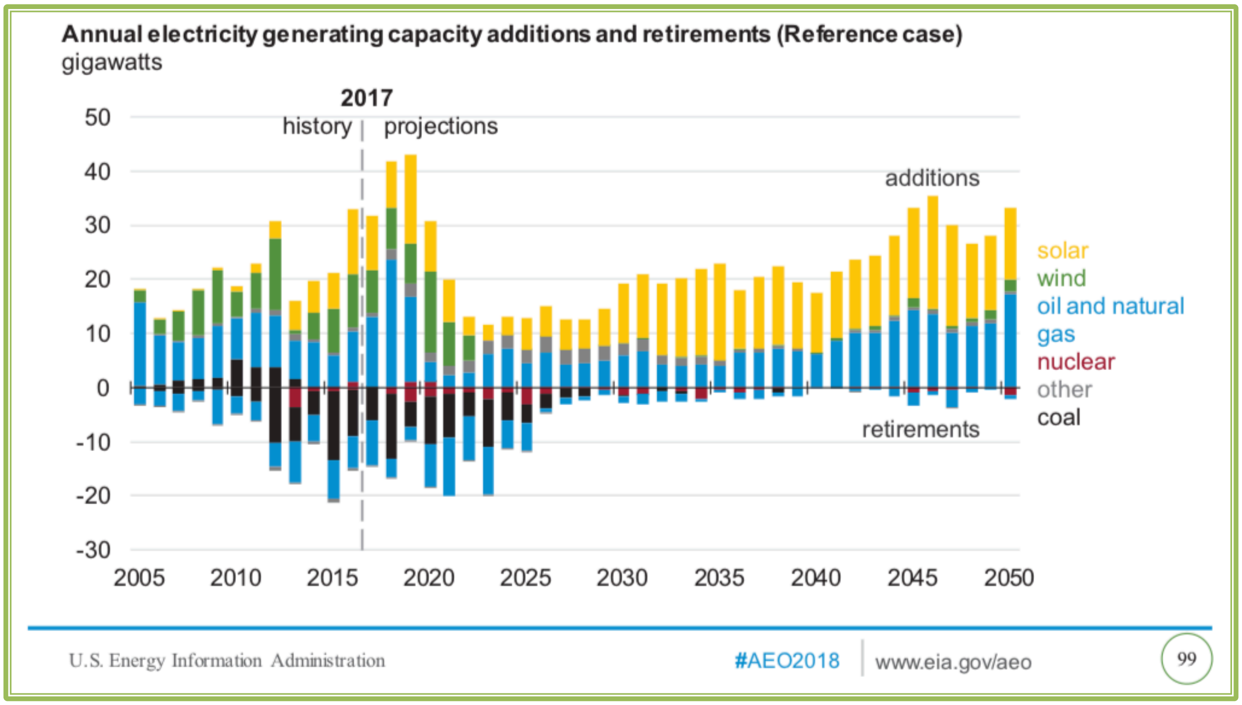
[15] Data compiled by CRI from PJM and MISO queue data

National projections for renewable power production

As shown in Figure 2.2, the U.S. Energy Information Administration (EIA) projects that on a nationwide basis, solar and wind power will continue to provide a substantial fraction of new generating capacity additions over the next several years, with solar energy expected to become the dominant source over the long term.

The decline in projected wind capacity additions a few years out is driven by the potential effects of the expiration of the federal production tax credit available for new wind projects.[16] See the discussion below on federal incentives.

Figure 2.2[17] - Projected National Generating Capacity Additions



EIA has been criticized for under-projecting wind and solar contributions in its Annual Energy Outlooks (AEO) and issued a special report on the subject.[18] While the report generally defended the AEO forecasting methods, data in the report showed that EIA's forecasts for both wind and solar development increased significantly over time, especially for utility-scale solar.[19]

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[16] "New wind capacity additions continue at much lower levels after the expiration of production tax credits in the early 2020s.", Annual Energy Outlook 2018, February 6, 2018, U.S. Energy Information Administration, p. 100
[17] Annual Energy Outlook 2018, February 6, 2018, U.S. Energy Information Administration
[18] Wind and Solar Data and Projections from the U.S. Energy Information Administration: Past Performance and Ongoing Enhancements, March 2016, U.S. Energy Information Administration.
[19] Ibid. Figures A-2, A-9, A-10

PPA pricing

National trends in renewable energy pricing

PPA contract prices for both solar and wind power projects in the U.S. have been declining over the last decade due to a number of factors including reductions in equipment costs and "soft costs", as well as improvements in efficiency and operation. Prices offered by many new, large-scale projects are now competitive with conventional power – and in some cases are lower.

Figures 2.3 and 2.4 show the history of PPA prices for "utility scale", grid connected wind and solar projects.[20] Prices vary regionally, with the lowest prices available from the interior regions of the nation where excellent wind and solar resources are available.

Figure 2.3[21] - Trend of Levelized Wind Power PPA Prices

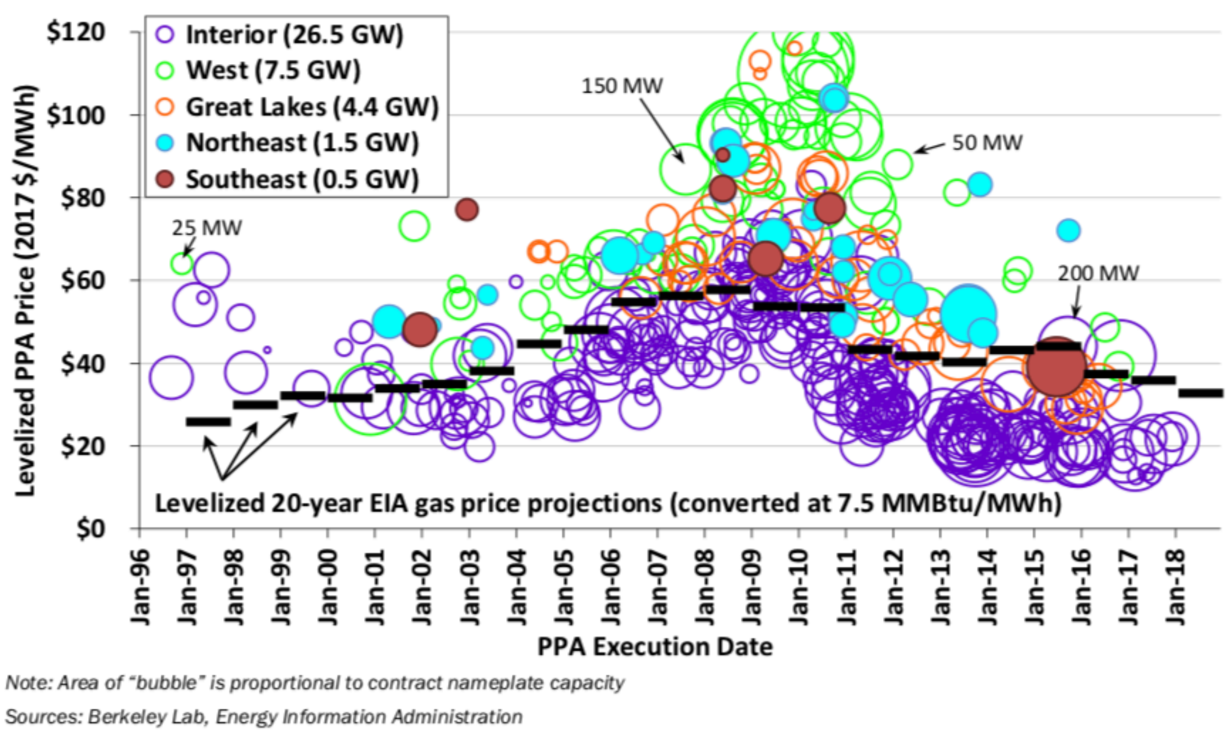


Figure 50. Levelized wind PPA prices by PPA execution date and region

[20] Pricing data does not include distributed resources such as rooftop solar projects
[21] 2017 Wind Technologies Market Report, U.S. Department of Energy

Figure 2.4[22] - Trend of Levelized Solar Power PPA Prices

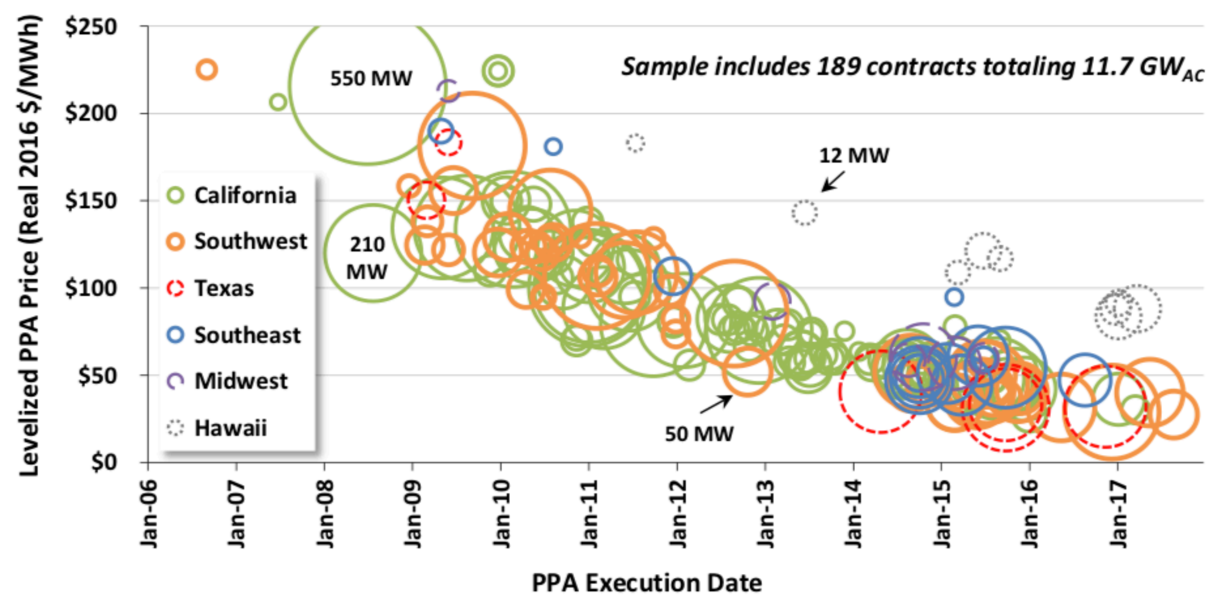


Figure 18. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: Full Sample

Regional PPA pricing

Table 2.3 lists projects from the LevelTen Energy Marketplace[23] located in PJM states. The data show that PPAs are being offered in this region at attractive prices relative to projected power values. Prices quoted are for energy (i.e. hourly power production) plus RECs.

> PPAs are being offered by a number of new wind and solar projects under development in the PJM states that are comparable to, and sometimes lower than conventional power prices.

The attractiveness of a PPA price is measured not in absolute terms, but in comparison to the value of power at the project location. Table 2.3 presents PPA prices as well as locational, 15-year levelized projected energy values for each project as estimated by LevelTen Energy.[24]

Solar projects under development in Virginia and North Carolina are especially attractive, while the best wind projects are located toward the western edge of PJM.

[22] Utility-Scale Solar 2016, September 2017, Lawrence Berkeley National Laboratory

[23] LevelTen Energy is a renewable energy company that provides access to its Marketplace of national project data to registered users.

[24] The LevelTen Energy Marketplace data is constantly being updated. The Marketplace roster of available wind and solar projects changes as new projects are posted by developers and as committed projects are removed from the database. Developers may change price quotes and LevelTen's estimates of future power prices are continually updated with forward market price quotes.

Table 2.3[25] - Sample of Regional PPA Price Offers – New Wind and Solar Projects

Project ID	Size (MW)	Annual Production (MWH)	State	Projected In-Service Date	15-Year Flat PPA Price ($/MWH)	Levelized Power Value ($/MWH)	Power Value Above PPA Price ($/MWH)
Wind Power Projects							
1199	150	468,000	IL	Q4 2020	$ 27.00	$ 28.79	$ 1.79
1021	200	200,000	OH	Q2 2020	$ 27.36	$ 26.92	$ (0.44)
129	100	445,672	WV	Q2 2020	$ 34.00	$ 33.50	$ (0.50)
964	60	200,000	IN	Q4 2019	$ 28.30	$ 21.97	$ (6.33)
125	50	191,000	PA	Q4 2019	$ 38.50	$ 30.96	$ (7.54)
Solar Power Projects							
1402	75	169,000	NC	Q4 2021	$ 28.50	$ 38.51	$ 10.01
1059	50	107,000	VA	Q4 2020	$ 25.50	$ 34.75	$ 9.25
39	65	155,000	VA	Q2 2021	$ 33.00	$ 38.65	$ 5.65
216	80	182,000	VA	Q2 2020	$ 33.00	$ 37.94	$ 4.94
1398	75	165,000	VA	Q3 2021	$ 34.59	$ 38.43	$ 3.84

The table above present data on some of the more attractive projects in the Marketplace, but it is important to note that not all projects under development are equally attractive. In fact, the range of PPA prices offered is very broad across projects, and when combined with differences in regional power values leads to a wide variation in attractiveness.

Figures 2.5 and 2.6 are histograms of Marketplace data for projects in PJM states, displaying the number of projects in various ranges of PPA prices relative to projected market power values. The green bars show projects offering PPAs that are either below projected market power values or within $5.00/MWH of those values. Yellow bars show projects priced above projected market power values. A large number of very attractive solar projects are under development, as are a handful of wind projects.

It is important to note that the price offers in Table 2.4 include all associated Renewable Energy Credits. These projects are even more attractive, therefore, than the energy price comparison would indicate. See Section 3 of this report for discussion of REC value and its effects on overall project value.

As can be inferred from Figures 2.5 and 2.6 and seen in the procurement scenario details included in Appendix 4, the attractively priced Virginia solar projects are creating the opportunity for an SOS strategy based on PPAs to potentially be cheaper than conventional power.

[25] Data from the LevelTen Energy Marketplace compiled by CRI.

Figure 2.5[26] - Summary of Regional Wind PPA Pricing

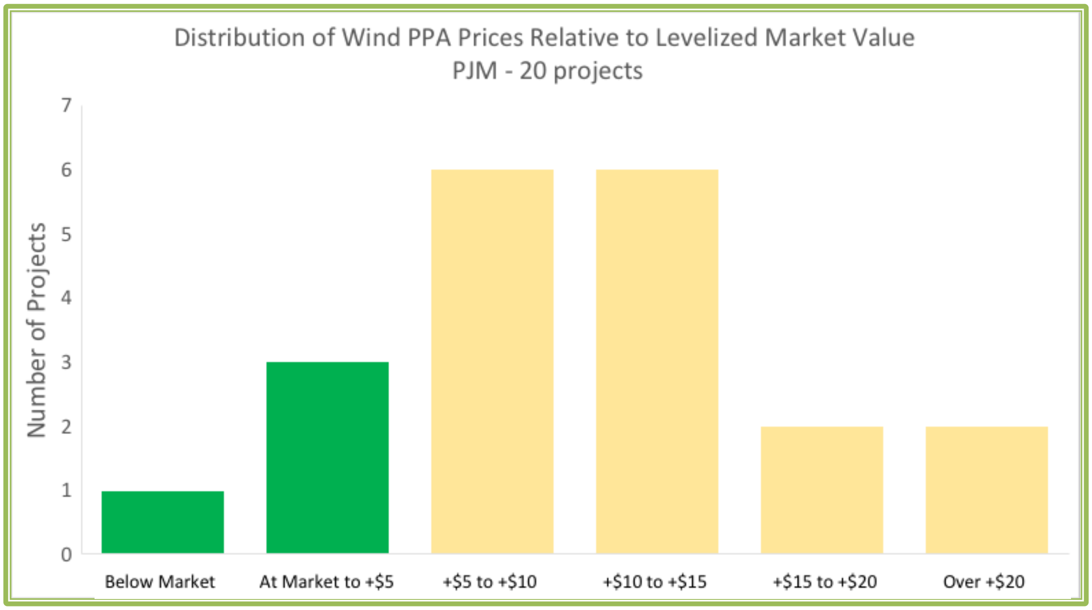
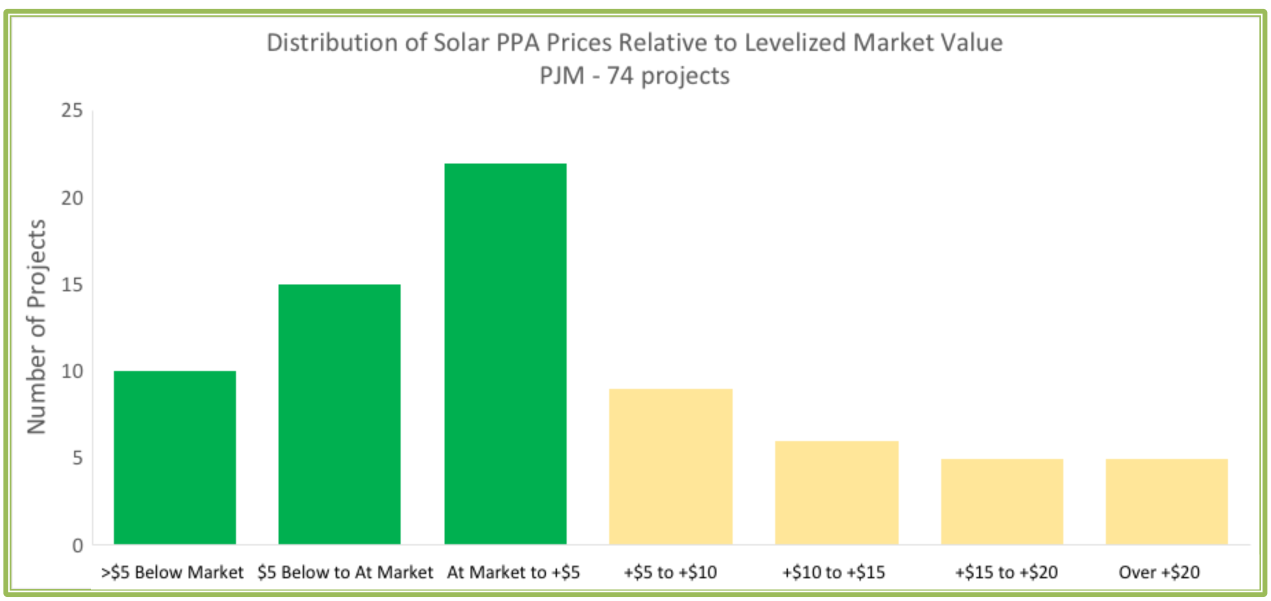


Figure 2.6[27] - Summary of Regional Solar PPA Pricing



[26] Data from the LevelTen Energy Marketplace compiled by CRI
[27] Ibid

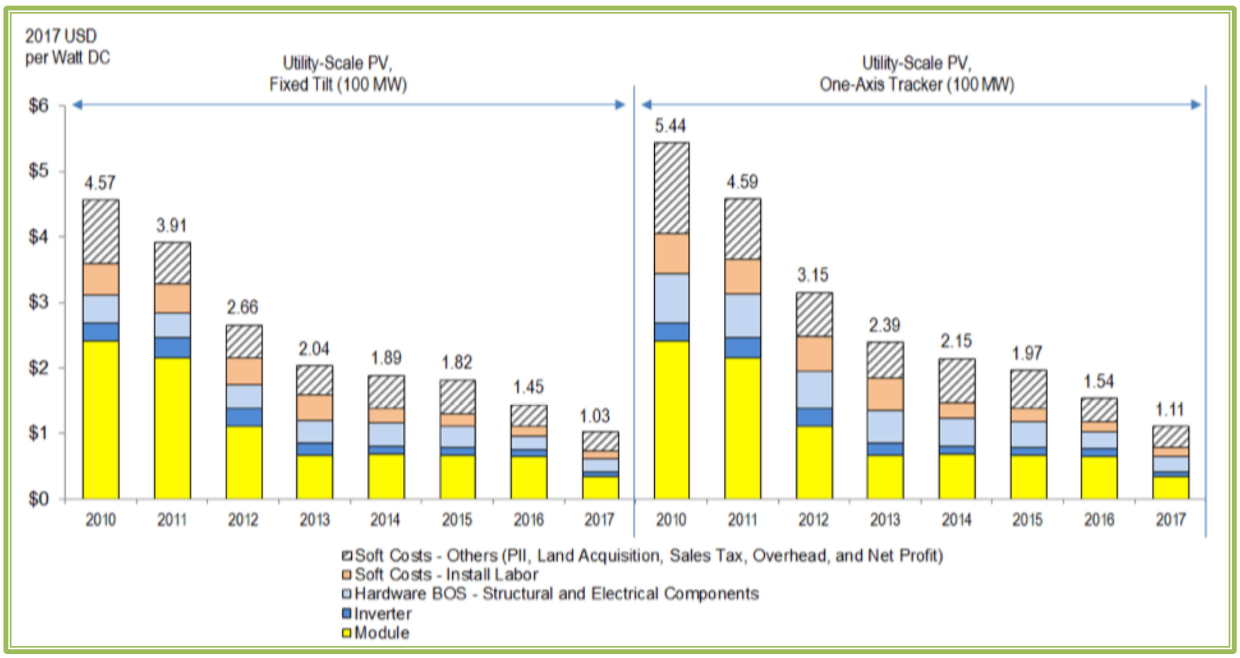
Future projections for renewable energy costs

The data presented above represent recent trends and a snapshot of project availability and pricing at the present time. The data suggest that projects with favorable economics are available to support a shift in SOS procurement toward long-term renewable PPAs. Future renewable project pricing is, of course, uncertain. The information below provides information on key drivers of future PPA prices.

Construction costs have been declining rapidly for utility-scale solar and to a lesser extent for wind. Projections are for cost declines to continue, promising increased competitiveness with conventional power prices and the potential for lower price offers from new solar and wind projects.

Figure 2.7 shows the National Renewable Energy Laboratory's (NREL) benchmark modeling results for the construction costs of large (100MW) fixed-tilt and single axis tracking solar photovoltaic projects. While the absolute values of the NREL benchmarks are not in complete agreement with other federal data sources[28], the trend is consistent.

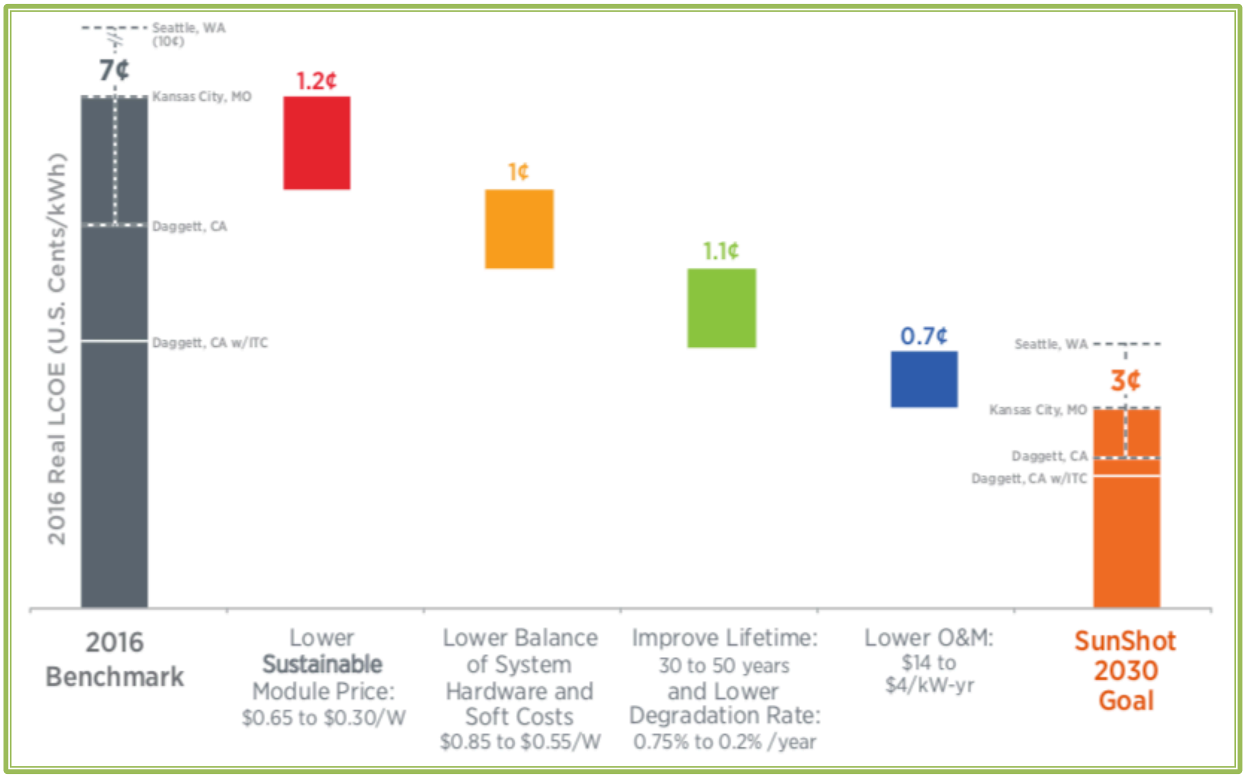
Figure 2.7 [29] [30] - History of Utility-Scale Solar Construction Costs



[28] Today in Energy, March 21, 2018, U.S. Energy Information Administration
[29] U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017, September 2017, National Renewable Energy Laboratory
[30] In examining cost data for solar projects, it is important to distinguish between costs per Watt "DC" and costs per Watt "AC". The DC (direct current) figure represents the total costs divided by the total direct current output of all solar panels. The AC (alternating current) figure represents the total costs divided by the maximum alternating current output of the inverter(s). Most utility scale solar systems have higher DC ratings than AC ratings. Note that most cost figures for solar projects are quoted per Watt DC.

The U.S. Department of Energy's Sunshot Initiative projects further declines for solar power costs in the decade ahead. Figure 2.8 shows Sunshot's current target of 3 cents per kWh[31] for the levelized pricing from new utility scale systems, and the potential contributors to the cost decline from current levels.

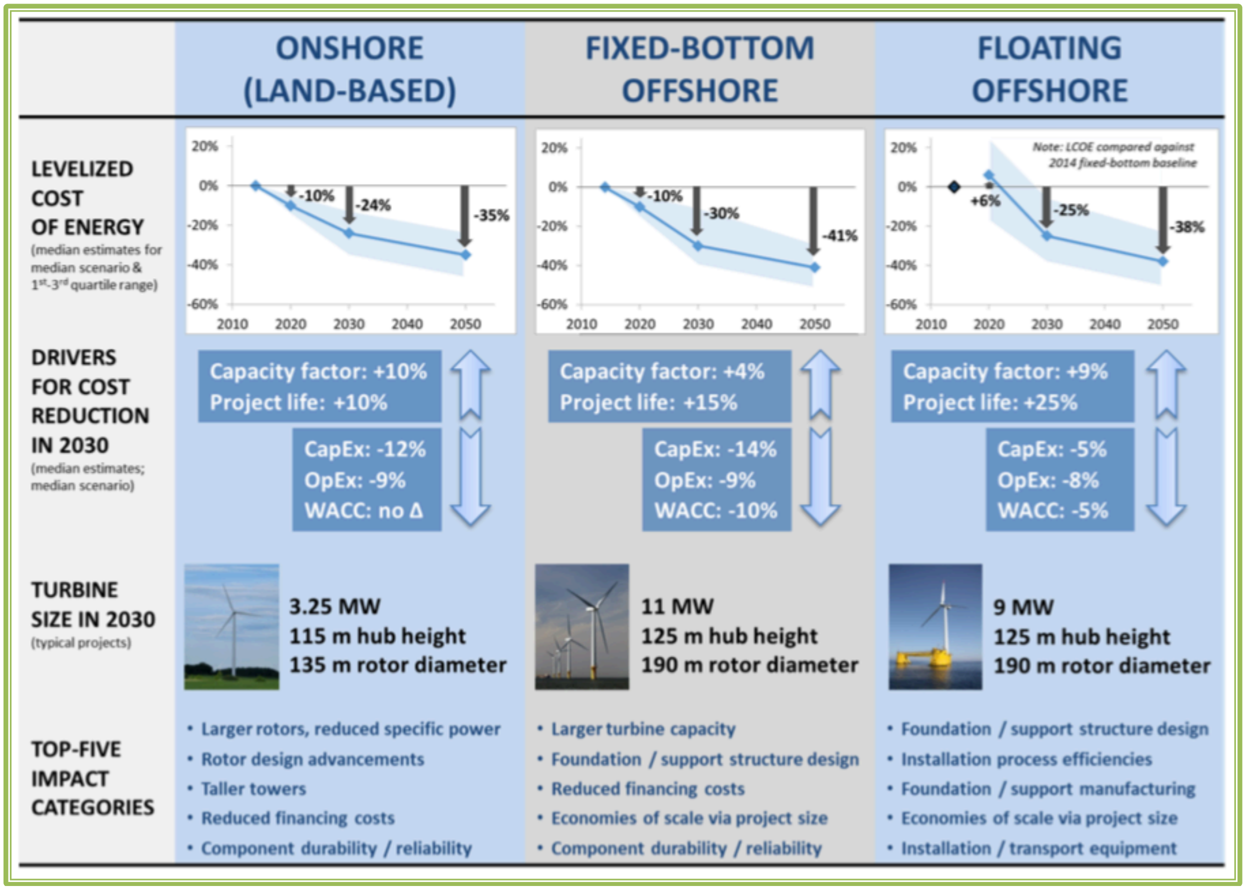
Figure 2.8[32] - U.S. DOE Sunshot Goals for Solar Power Cost Reductions



[31] The Sunshot cost targets assume no federal tax credits, state or local incentives, and an "average climate". The lack of incentives in the Sunshot figures explains to a significant degree why PPA prices currently offered by utility scale solar projects are already much lower than the 2016 benchmarks shown in the Sunshot information.
[32] The Sunshot 2030 Goals, U.S. Department of Energy

Wind power also has the potential for further cost declines. A 2016 study led by Lawrence Berkeley National Laboratory presented a summary of information gathered from 163 wind energy experts worldwide.[33]

Figure 2.9[34] - U.S. LBL Data on Projected Wind Power Cost Reductions



<u>Government financial incentives</u>

The federal investment tax credit (ITC) has been an important incentive for solar project development as has been the production tax credit (PTC) for wind projects. Under current tax law these federal incentives are set to ramp down in the coming years. The production tax credit for wind power is available only to projects that commence construction by the end of 2019, after which time the credit expires. The federal investment tax credit for solar projects, in contrast, continues indefinitely into the future, ramping down from 30% for projects commencing construction by the end of 2019, to 26% in 2020, 22% in 2021, and 10% thereafter.

Renewable energy projects also benefit from tax advantages that apply more broadly across industries including accelerated depreciation and bonus depreciation. Bonus depreciation, in

[33] Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts, June 2016, Lawrence Berkeley National Laboratory
[34] Ibid

particular, has been a benefit to capital investments made since 2008, but is scheduled to sunset after 2019.[35]

The expiration and ramp-down of these incentives will put upward pressure on PPA prices that will counter the downward pressure from declining construction costs, efficiency and operation improvements. As noted above, on balance there is concern that new wind power development may decline in the face of expiring tax incentives, while there is optimism for the continued competitiveness of solar power.

[35] Modified Accelerated Cost-Recovery System (MACRS), fact sheet, U.S. Department of Energy

SECTION 3 – PURCHASING SCENARIOS

To illustrate the potential effects of including long-term PPAs into the SOS purchasing strategy, as well as the potential effects of alternate procurement options, a number of scenarios have been analyzed.

Ramp rates

- Ramp Rate #1 – Reach 70%[36] of SOS requirements in 3 years[37]
- Ramp Rate #2 – Reach 90% of SOS requirements in 6 years
- Ramp Rate #3 – Reach 90% of SOS requirements in 12 years

Ramp Rate #1 is consistent with a scenario modeled in the Clean Energy DC plan, meshes with the roll-off of 3-year supply contracts that are part of the current residential SOS portfolio, and represents the most rapid ramp up of renewable energy purchasing that might reasonably be executed. The 70% target leaves significant room for potential declines in SOS requirements over time (e.g. due to energy efficiency improvements and/or load migration away from SOS). Additional purchases of renewables could be made in future years if SOS load remains robust.

Ramp Rate #2 represents a slightly more measured purchasing program, but with a higher ultimate target. The annual purchase volumes in later years could be adjusted to respond to changes in SOS requirements due to the factors described above. The 90% target also may also represent the upper range of fixed-price purchasing volumes consistent with a detailed risk management evaluation as discussed in Section 4 of this study.

Ramp Rate #3 represents a much more gradual purchasing program, with the final year of the ramp-up corresponding to the final year of the Clean Energy DC planning horizon. This approach provides the greatest flexibility in responding to changes in SOS requirements and allows purchasing strategy to be most responsive to evolving market conditions, at the expense of addressing GHG reductions more slowly.

As shown in Table 3.1, each ramp rate correlates to a different annual PPA contracting requirement, with faster ramp rates associated with larger annual procurements. Faster ramp rates, therefore, can result in selecting larger projects or multiple projects each year. Access to larger projects is advantageous, particularly for purchasing wind power, and purchasing from multiple projects in a given year accelerates portfolio diversity. Extending PPA purchasing over a longer time frame, on the other hand, precludes access to large wind projects, but creates a more diverse set of smaller projects in the portfolio over time.

[36] The "CleanEnergy DC Omnibus Amendment Act of 2018" as introduced calls for 80% of the SOS requirements to be supplied from renewable PPAs and a 3-year ramp (lines 121 – 136). Selecting an 80% target vs. 70% does not alter the conclusions of this study.

[37] The percentage of SOS supplied by renewables is the total number of kilowatt-hours of renewable energy purchased during the year, divided by the total number of kilowatt-hours of SOS service consumed by customers. There is no specific correspondence between the hour-by-hour production of the renewable facilities and the hour-by-hour requirements of SOS customers. This is the same arithmetic implicit in the District's RPS law, and it is the common approach to describing renewable energy content.

Table 3.1 – Ramp Rate Scenarios

Scenario	Ramp Rate	Annual Procurement
#1	70% of SOS in 3 years	650,000 MWH
#2	90% of SOS in 6 years	420,000 MWH
#3	90% of SOS in 12 years	210,000 MWH

Note that following the execution of a PPA with a new renewable project, the completion of construction of that project typically occurs within 18 to 36 months. There will be a lag, therefore, between the ramp up of procurement activity and the ramp up of power delivery. As shown in Figure 4.3 in Section 4, conventional energy purchases would make up the balance of SOS requirements during the ramp up of renewable energy production.

Sourcing

For each of the three ramp rate scenarios, a detailed purchase plan is modeled. The baseline purchasing parameters are:

- Each PPA is for the full output of a project.
- All PPAs are with new wind and solar projects.
- All projects are sourced from PJM states.

In addition to aligning with geographic boundaries consistent with the District's RPS, the baseline sourcing parameters offer two advantages:

- Selecting the best individual project(s) offered each year allows for a clear, competitive procurement process.
- New wind and solar projects represent the largest sources of renewable energy PPAs.

In addition to the baseline purchasing parameters, two alternative purchasing options are evaluated:

- Alternate #1 – PPAs for shares of portfolios of new renewable energy projects
- Alternate #2 – Purchases from projects located both inside and outside PJM states

Alternate #1, portfolio purchasing, is a new option becoming available in the marketplace.[38] A portfolio is typically composed of a few very large renewable power projects, and end users purchase a share of the portfolio output under a single PPA contract. This gives end users the pricing benefits of buying from large projects, provides supply diversity within each PPA, and allows end users to specify precise purchase volumes rather than adjusting their purchase volume to the outputs of available projects. Portfolio projects are chosen to diversify location, to balance

[38] LevelTen Energy, which has provided access to its Marketplace data and analytics in support of this study, offers PPAs from project portfolios. Large corporations are also arranging for purchases from multiple-project portfolios and making portions of that portfolio available to other buyers. The recent announcement by Apple, Akamai, Etsy and Swiss Re, who are sharing in a portfolio comprised of a Virginia wind power project and an Illinois wind farm is an example. https://www.prnewswire.com/news-releases/apple-akamai-etsy-and-swiss-re-collaborate-to-accelerate-renewable-energy-development-in-illinois-and-virginia-300692261.html

peak and off-peak generation (solar/wind ratio), to stabilize the overall value of the power and to minimize energy market risk.

Alternate #2, expanded power sourcing, provides the economic advantage of sourcing wind and solar power from the most attractive locations nationally.

As was found by the District's Department of General Services (DCDGS), existing wind projects likely offer the largest opportunity for additional volumes of attractively priced renewable energy. DCDGS entered into a PPA with an existing wind power project in 2015 after determining that it was more economically attractive than new projects begin offered at that time. Operating wind projects without long-term commitments sell power into the spot or short-term wholesale market, and their PPA price offers are generally be close to the prevailing market prices. These projects have shown interest in selling at least a portion of their total output under long-term PPAs.

For other sources of renewable energy that qualify as Tier 1 resources under the District's RPS law, the number of projects available is limited and/or the output of the facilities is relatively small. It may be worth further investigation, nevertheless, to assess the potential value of including these types of resources in an SOS renewable energy procurement in niche roles.

Projects other than new solar and wind, were not included in purchasing scenarios in this study due to the lack of available PPA pricing data.

Modeling results

Figure 3.1 presents a projection of future SOS prices based on the current SOS purchasing strategy and shows the potential benefits of entering into long-term PPAs under the three different ramp rate scenarios. Sourcing is consistent with the baseline parameters described above, and PPA prices were obtained from quotes in the LevelTen Energy Marketplace. Appendix 3 provides details of the SOS pricing model, and Appendix 4 provides the detailed data used in each scenario.

Entering into PPAs priced below the projected forward value of conventional market-priced power results in lower SOS costs for all ramp rate scenarios. The 3-year and 6-year ramp rate scenarios provide similar benefits in the short term. The 6-year ramp rate scenario ultimately delivers better results, however, owing to its larger renewable content. The 12-year ramp rate scenario achieves the smallest long-term benefit, because the smaller annual procurements limit the ability to purchase from larger, better-priced wind power projects.

The fact that savings are occurring in the short term, as well as in the long term, is an important result. It shows that not only are PPAs priced attractively relative to long-term market price expectations, they are competitive with power prices today. SOS customers would not, therefore, be asked to pay more today in return for a projected long-term benefit. The slightly higher SOS rates in 2022 and 2023 are due to the end of the lagging effect of the three-year FRS contracts. The "step-downs" for the PPA strategy in 2028 and 2032 are caused by decreases in alternative compliance payment levels in those years, and therefore in projected RPS compliance costs. These changes are smoothed if the current FRS strategy is continued.

It should be kept in mind, in reviewing these results that future market prices for energy, both in the renewables market and the conventional market, are subject to significant uncertainty. Energy price forecasts are largely extrapolations of current market conditions and are projected as steady rates of change in the future. History would indicate that technology, market and other forces create much greater year-to-year variability in energy prices than forecasts imply, and sea changes are possible. The emergence of low cost solar energy and the effects of fracked gas on conventional power markets were not reflected in long-term market expectations 10 years ago.

PPAs with new solar and wind projects are priced attractively relative to long-term market price expectations and are competitive with power prices today. SOS customers would not need to pay more today in return for long-term benefits

Figure 3.1 – SOS Price Projections – Regional Project Purchases – All Ramp Rates

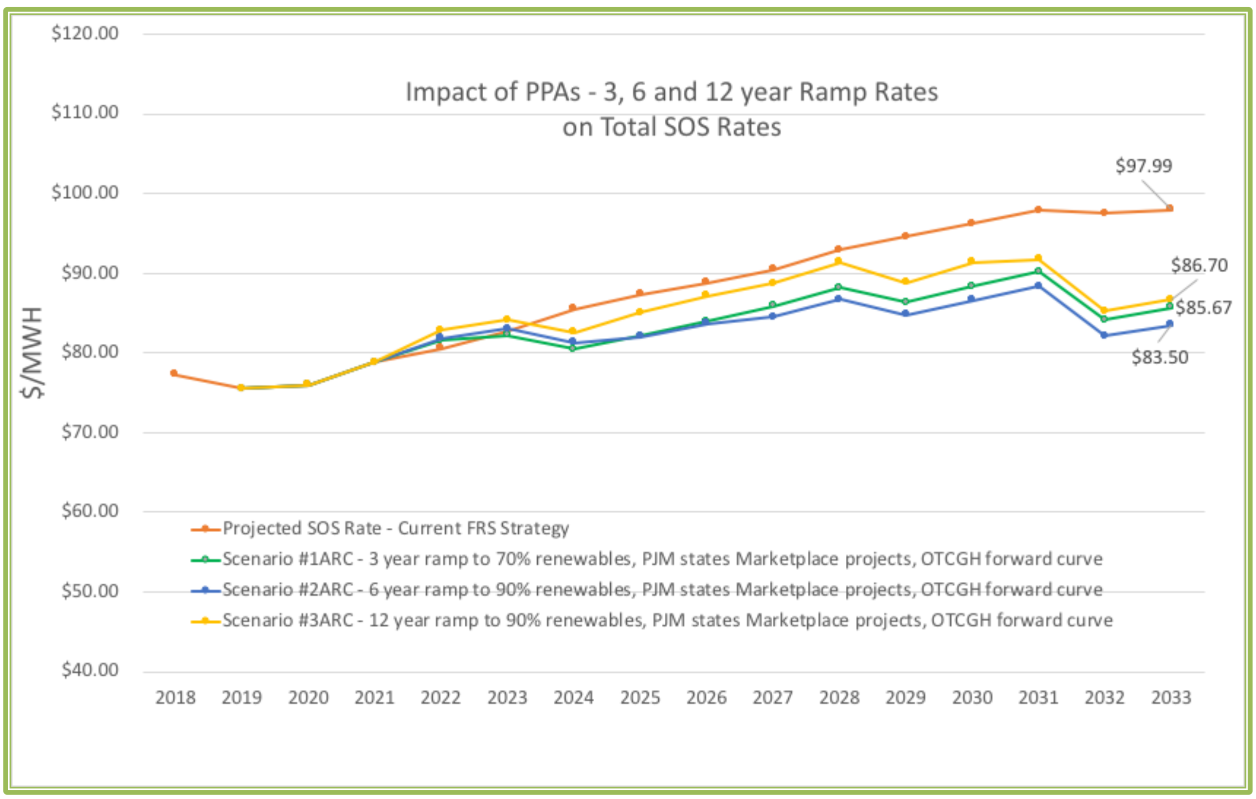
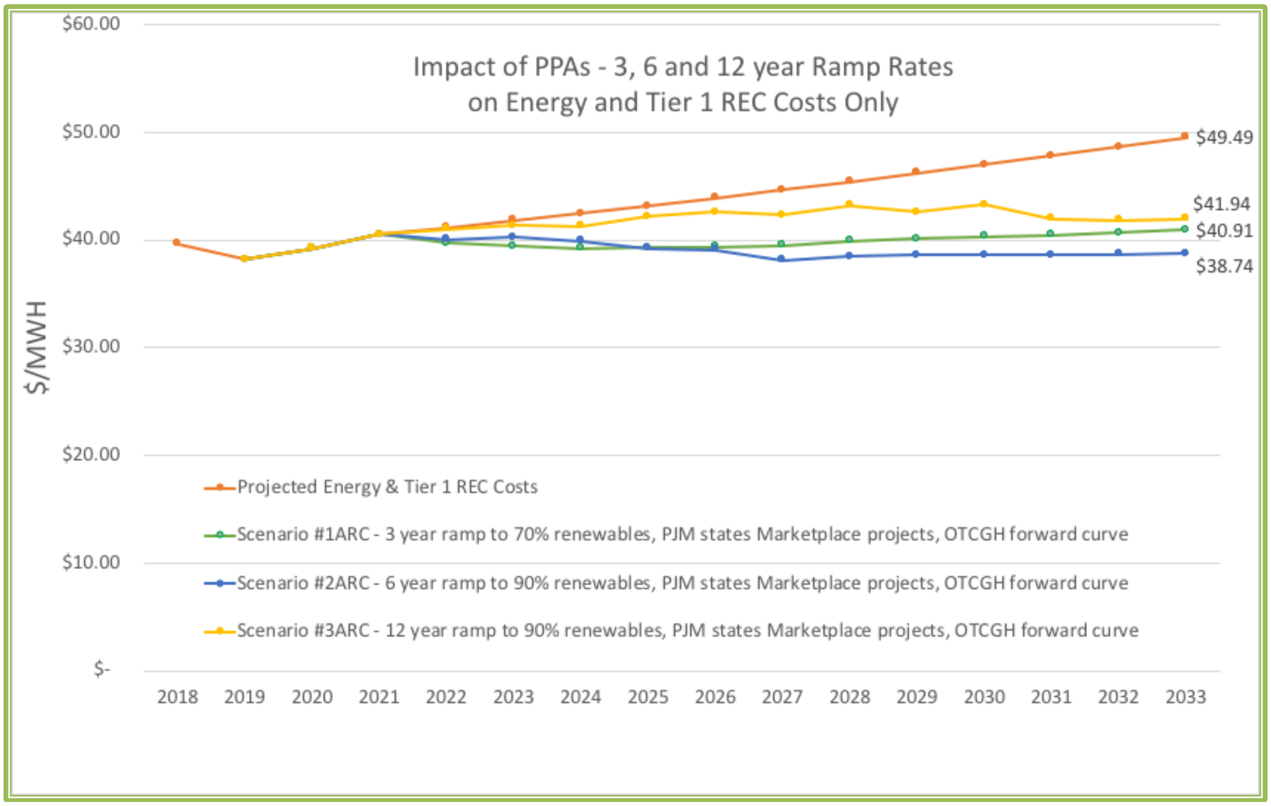


Figure 3.2 presents a streamlined version of the same comparisons shown in Figure 3.1 based on a reduced set of parameters – electric "energy" and Tier 1 RECs only.[39] This streamlined comparison eliminates all of the other SOS cost elements that are essentially comparable under either the current SOS procurement method or the PPA-based methods as described in Appendix 3.

Figure 3.2 – Energy and Tier 1 REC Price Projections – Regional Project Purchases – All Ramp Rates



[39] In addition to "energy" (i.e. hour-by-hour electricity generation), renewable energy projects can also sell "capacity" into regional power markets. There are, however, significant uncertainties related to the economic value of capacity owing to a history of changing market rules. Monetizing the value of capacity is also complex. As a result of these uncertainties and complexities, PPAs are often structured to include only energy and RECs, leaving the project owner with the opportunity and responsibility to manage and monetize capacity value.

Figure 3.3 shows the potential benefits of purchasing portfolio shares compared to the 12-year ramp rate scenario from Figure 3.2. The sample portfolio developed for this analysis includes larger, more economic wind projects than could not be purchased for a 12-year program relying on individual project selection. A portfolio product could allow the 12-year ramp rate to achieve long-term results similar to those achieved by the 6-year / 90% ramping scenario.

Figure 3.3 – Energy and Tier 1 REC Price Projections – Portfolio Purchasing – 12-year Ramp Rate

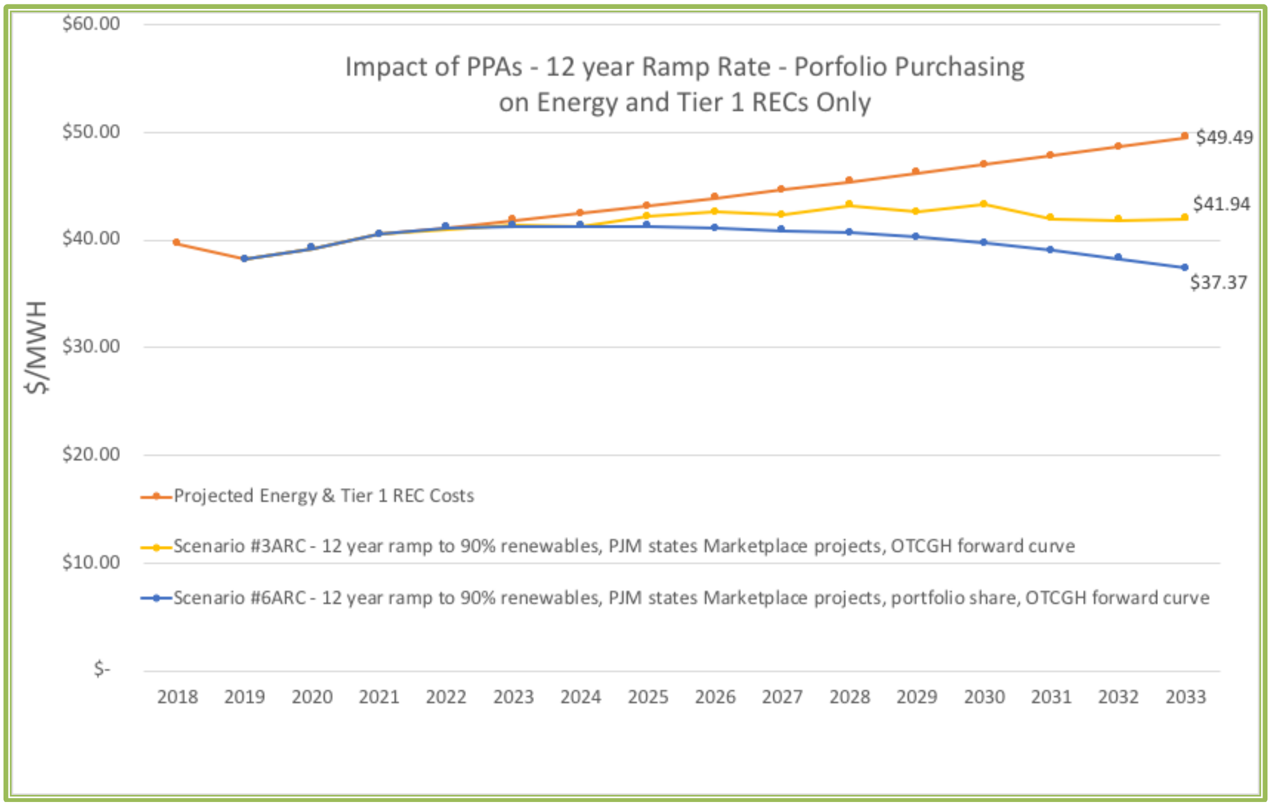
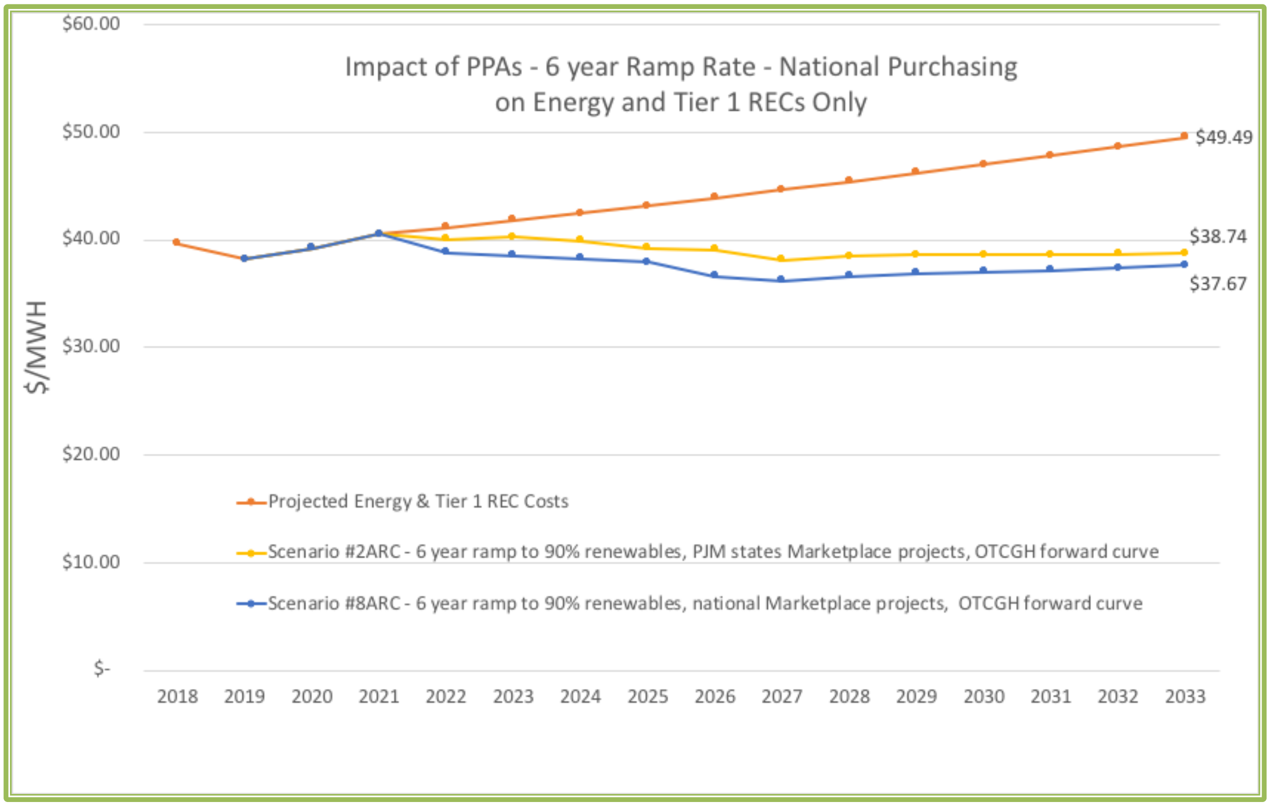


Figure 3.4 shows the benefits of purchasing from the best renewable energy projects available nationally, where "best" is defined as offering the lowest PPA rates relative to the projected value of that power in the relevant geographic market. The best wind projects cataloged in the LevelTen Energy database are located in Texas and Oklahoma, and the best solar projects are located in Texas and in the local Virginia/North Carolina region. The attractiveness of Texas and Oklahoma projects relate primarily to high average wind speeds for wind projects and high levels of solar irradiance for solar projects.

Figure 3.4 – Energy and Tier 1 REC Price Projections – National Project Purchases – 6-Year Ramp Rate



Future PPA pricing vs. future conventional electricity market prices

The scenarios modeled in this study are based on PPA prices available in the market today and on current forecasts of future conventional power prices. The attractiveness of PPA offers in future years will depend on future trends in renewable power pricing measured against then prevailing conventional forecasts of power prices.

EIA currently forecasts that nominal electricity generation prices in the U.S. will rise at an average rate of 1.9% between 2019 and 2033.[40] EIA forecasts real prices to decline by .5% per

[40] EIA Annual Energy Outlook 2018 - Interactive Table Viewer – Nominal Electricity Generation Prices 2019 (6.5 cents per kWh) to 2033 (8.5 cents per kWh)

year over that same time frame.[41] The forecasts for real cost declines for both wind and solar energy in the coming years, as described in Section 2 of this study, imply that new wind and solar power projects should maintain their competitiveness with conventional generation.

[41] EIA Annual Energy Outlook 2018 - Interactive Table Viewer – 2017 Constant Dollars Electricity Generation Prices 2019 (6.3 cents per kWh) to 2033 (5.9 cents per kWh)

4 – STANDARD OFFER SERVICE

Legislative and regulatory framework

Standard Offer Service (SOS) is the generation and transmission supply service[42] available to District of Columbia electric customers who are not supplied by competitive electricity suppliers. As "SOS Administrator" Pepco[43] sells SOS to covered customers and secures the needed generation supply through a wholesale procurement process.

The Code of the District of Columbia § 34–1509 Standard Offer Service provides the broad requirements for the service, and District of Columbia Municipal Regulations Chapter 15-41 provides details on its structure.[44] In February 2003 the DCPSC docketed Formal Case 1017 (FC1017) initiating the process of determining the structure of SOS. FC1017 remains an open docket. Every other year, the DCPSC undertakes a formal review of the SOS procurement process[45], and each year it approves a procurement RFP, associated contract documents and bid results. In addition to regulations, certain particulars of SOS procurement are documented in Commission Orders in the FC1017 docket.

SOS supply is procured for three customer groups - residential, small commercial, and large commercial - defined as follows:

"The SOS Administrator shall establish three (3) groups of customers ("SOS Customer Groups"):

(a) Residential Customers shall include customers served under Electric Company Rate Schedules: R, AE, R-TM, R-TM-EX, RAD, and Master Metered Apartment customers, subject to any revisions made to those tariff sheets made by the Commission;

(b) Small Commercial Customers shall include the customers served under Electric Company Rate Schedules: GS-LV non-demand, GS-3A non-demand, T, SL, TS, TN and SL-TN, subject to any revisions made to those tariff sheets made by the Commission; and

(c) Large Commercial Customers shall include all commercial customers except those defined as Small Commercial Customers." [46]

[42] In some documents SOS prices are quoted as the sum of generation and transmission charges, while in other documents the generation supply charges are stated separately from transmission charges.
[43] District of Columbia Municipal Regulations Chapter 15-4101.1
[44] See Appendices 5 and 6 of this report for full text of the relevant Code and Regulations.
[45] District of Columbia Municipal Regulations Chapter 15-4102.1 and 4102.2. The DCPSC issued Order 19431 on August 9, 2018 initiating the next biennial review.
[46] District of Columbia Municipal Regulations 15-41 4102.3

SOS volumes

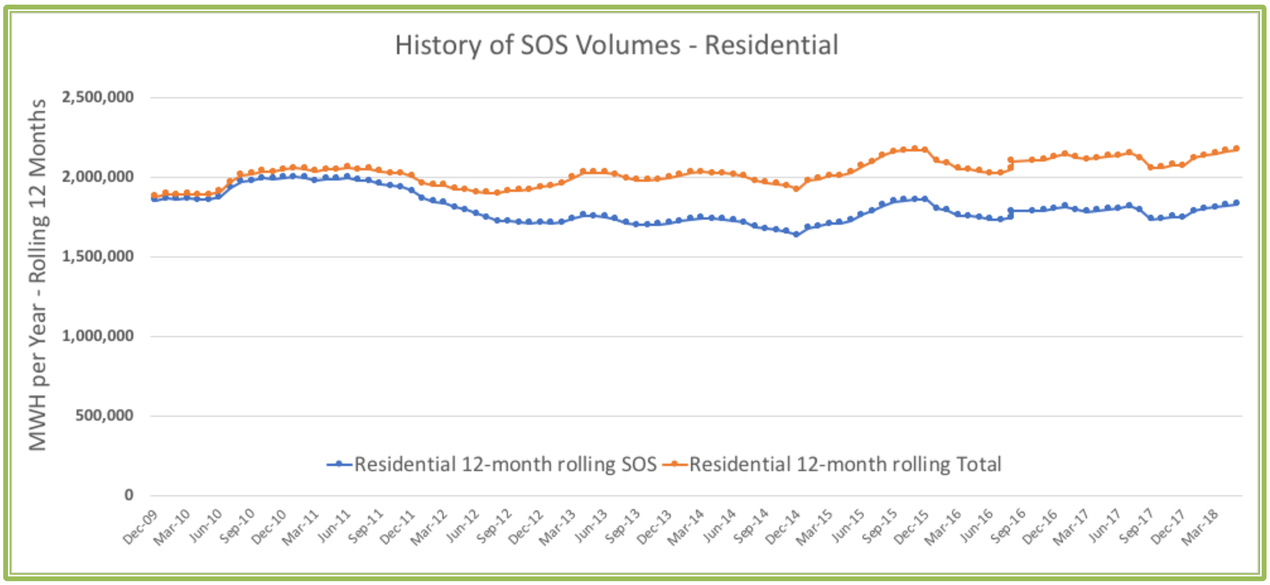
For the 12 months ended May 2018, residential customers purchasing SOS used approximately 1,800,000 MWH of electricity representing 84% of all residential electricity use in the District. Commercial customers purchasing SOS used 1,150,000 MWH in the 12 months ended May 2018, representing 14% of all commercial electricity use. In total SOS has represented approximately 28% of total D.C. electricity use over the past three years.[47]

> The history of SOS volumetric stability supports consideration of a procurement strategy based on long-term PPAs.

As shown in Figure 4.1, while total residential load in the District has grown over the past several years, correlated to a growth in the number of residential accounts, competitive retail suppliers have come to serve a greater share of residential electricity requirements, absorbing that growth and supporting the stability of SOS load.

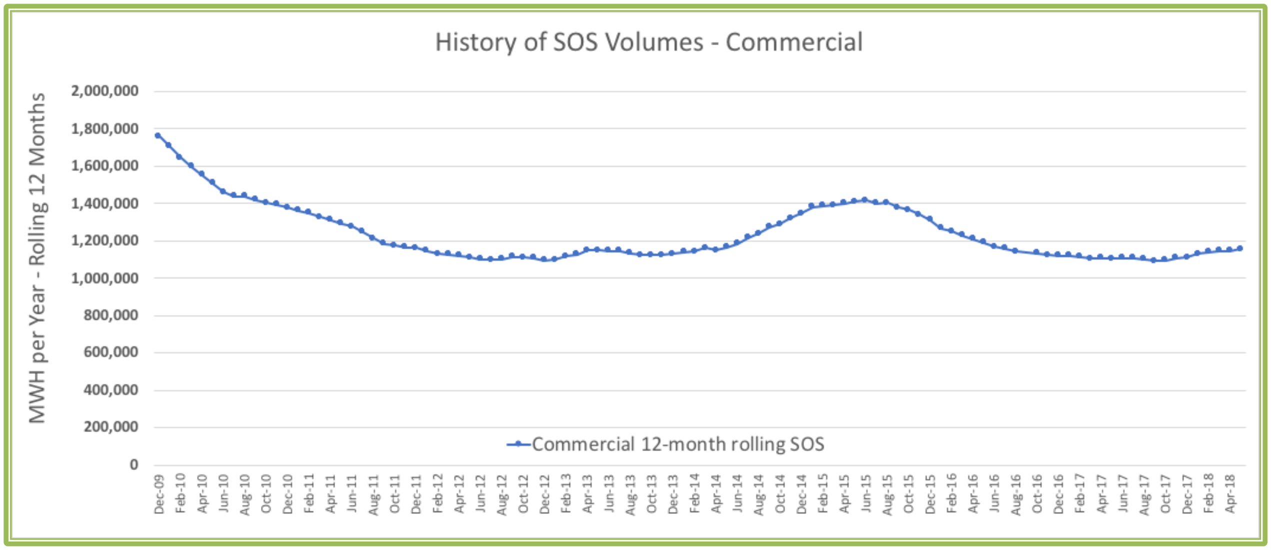
As shown in Figure 4.2, commercial SOS load has also been stable over the past several years, with a temporary increase in load (and number of accounts served) in the year following the January 2014 “Polar Vortex” weather event.

Figure 4.1 – History of Residential SOS Volumes



[47] Figures from Historical and Analytical Information for Electricity, Status of Electric Competition, DCPSC website https://www.dcpsc.org/Utility-Information/Electric/Historical-and-Analytical-Information-for-Electric.aspx

Figure 4.2 – History of Commercial SOS Volumes



On a 12-month rolling basis, over the past several years, the minimum combined residential and commercial SOS load has been approximately 2,800,000 MWH. Ignoring the temporary spike in commercial sales in 2015, the maximum combined load has been approximately 3,000,000 MWH. [48] This history of volumetric stability supports a long-term renewable PPA purchasing plan aimed at a high percentage of SOS requirements.

Current SOS structure

Since the inception of customer choice in the District, SOS has been structured to provide a price that is predictable in the near-term for all customers and to smooth out electric market price fluctuations in the medium-term for residential and small commercial customers. This does not mean that electricity prices have not varied substantially during any given year or from year-to-year. As the data in Table 4.2 later in this Section show, SOS customers have experienced seasonal swings in prices as high as 3.5 cents per kWh and year-to-year changes as high as 1.5 cents per kWh.

> The current FRS SOS structure provides short-term price certainty (one year) for all customers, and "smoothing" of year-to-year variations in conventional market prices for residential and small commercial customers (three years).

The two key features of the current SOS structure used to accomplish these objectives are:

- Full Requirements Service (FRS) wholesale contracts[49], and
- one-year or three-year contract terms.

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[48] Figures from Historical and Analytical Information for Electricity, Status of Electric Competition, DCPSC website https://www.dcpsc.org/Utility-Information/Electric/Historical-and-Analytical-Information-for-Electric.aspx

[49] District of Columbia Municipal Regulations 15-41 4100.2

In the FRS contract structure, a wholesale supplier provides all electricity needed by a specified percentage of the SOS customer base at a set of fixed prices per kilowatt-hour (kWh). The FRS supplier is responsible for, and the FRS price includes, all components of generation supply and RPS compliance:

- Generation supply
  - Energy
  - Capacity
  - Ancillary services
  - Wholesale supplier margin / risk management
- RPS compliance
  - Tier 1 RECs
  - Tier 2 RECs
  - Solar Carveout SRECs
  - Alternative Compliance Payments (as necessary)

FRS suppliers quote prices that correspond to the structure of each Pepco rate schedule. That detailed pricing structure is complex, reflecting seasonal differentiations, time-of-day differentiations, and block structures.[50] This detailed wholesale pricing structure simplifies the SOS Administrator's efforts in passing through wholesale costs to SOS customers, and it minimizes the need for cost allocations or true-ups of retail sales revenues against wholesale supply costs.

Each year wholesale bids are solicited to supply the various customer groups. Contracts supporting residential and small commercial SOS are for three years, while contracts supporting large commercial service are for one year.[51] Contracts run from June 1st to May 31st (either for one- or three-year periods as noted above).[52] [53]

Pepco adds certain cost elements to the FRS wholesale prices to develop the total SOS price including transmission charges billed through PJM, an administrative charge and applicable taxes.[54]

In the most recent SOS RFP process for supply contracts commencing on June 1, 2018, eight wholesale suppliers submitted bids and three were chosen for new contracts. Including the results of previous years' RFPs for residential and small commercial supply, a total of five different wholesalers are now providing SOS.[55]

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[50] See Pepco's D.C. tariff under Standard Offer Service – Rider "SOS" for details.
[51] District of Columbia Municipal Regulations 15-41 4101.6
[52] This annual window is the PJM "planning cycle". Among other things it coincides with the annual capacity market pricing cycle.
[53] See this link to Pepco SOS wholesale procurement processes http://www.pepcoholdings.com/about-us/do-business-with-phi/energy-suppliers/wholesale-suppliers/pepco-dc-sos-rfp/
[54] District of Columbia Municipal Regulations 15-41 4100.3
[55] DCPSC website: Utilities > Electric > Historical and Analytical Information for Electricity > Background Information > Winning Wholesale Suppliers for Standard Offer Service

Revised SOS structure to accommodate renewable PPAs

> Supplying SOS through long-term PPAs is best accomplished by shifting away from the current Full Requirements Service (FRS) procurement strategy.
>
> The PPA strategy provides more long-term cost stability, and comparable year-to-year price "smoothing" when compared to the current FRS strategy. Near-term SOS price certainty can be managed by maintaining "true-up" accounts.

The current SOS structure, which purchases all of the required electricity under FRS contracts, is not well suited to simultaneously entering into long-term electricity contracts with renewable energy projects. The two overlapping purchases would result in a duplicative supply of electricity, especially as PPA purchases grow over time to match nearly all SOS requirements.

The procurement approach best suited to PPAs combines those PPAs with the direct purchase of other electricity supply and RPS compliance components by the SOS Administrator, with aggregate costs properly allocated to SOS customer classes. The District's Department of General Services, in fact, shifted its electricity purchasing from FRS to this approach after it began to take delivery electricity under the wind power PPA it signed in 2015.

The electricity supply cost components combined by an FRS wholesale supplier in providing that service are very similar to the cost components that need to be combined by the SOS Administrator in the PPA approach. Table 4.1 shows the various electricity cost elements assembled to provide service under the current FRS SOS structure, contrasted to the elements aggregated in the PPA approach. Figures 4.3 and 4.4 present the same information in a diagrammatic form.

As seen in the table and figures, the PPA approach differs from FRS in a few ways:

1. Renewable PPA purchases replace some or all conventional power "block" purchases of energy.

   The FRS supplier purchases blocks of conventional wholesale supply to match most of the SOS customer requirements. The PPA supply, in contrast, is built on an increasing volume of renewable purchases, with conventional blocks used to supplement those purchases, especially in the early years of the transition.

2. Risk premiums are eliminated.

   Spot market power must be bought or sold by the FRS supplier to match its conventional power block volumes to actual hourly SOS customer needs. The FRS supplier includes an estimate of spot market power costs in its price and adds a risk premium to account for potential deviations from those estimates. In the PPA approach, spot market power is bought or sold to match renewable energy project production to the hourly SOS customer needs. No risk premium is paid, but the variability of purchase volumes and spot market prices introduce some variability into SOS costs.

3. SOS administrative costs are substituted for FRS supplier margins.

   FRS suppliers include a return on capital employed, other direct costs, overheads and profit margin in their prices. The PPA approach includes approved SOS Administrative costs. See the discussion of Administrative Charges later in this Section.

4. Some RPS compliance costs are covered by bundled PPAs

   The FRS supplier adds the cost of RECs needed to satisfy Tier 1 compliance into its fixed price. Those costs are generally based on short-term REC market pricing. In the PPA approach, RECs bundled into those contracts will cover some or all of the Tier 1 RPS compliance requirements. To the extent that the ramp up of PPA delivered volumes does not keep pace with RPS requirements, additional unbundled RECs would be purchased to make up the difference. Note that if PPAs are limited to 70% or 90% of total SOS volumes, per the scenarios analyzed in this study, some unbundled RECs might need to be purchased in the long term if the District decided to increase RPS requirements to a 100% target.

Table 4.1 – SOS Cost Elements

SOS Cost Element	Purchased by FRS wholesale supplier Current SOS	Added by SOS Administrator Current SOS	Purchased or Added by SOS Administrator PPA approach
Generation Supply			
Energy			
Round-the-clock or Peak Hour blocks of conventional power (from generation owners or traders)	X		X
Renewable PPAs (from generation owners)			X
Spot market power to balance hourly requirements with block purchases and/or PPAs (from PJM LMP market)	X		X
Installed Capacity (from PJM)	X		X
Ancillary Services (from PJM)	X		X
Risk management OPTIONAL (options, weather hedges, basis contracts, etc.)	X		X
FRS supplier risk premium and margin	X		
SOS Administrator procurement management and credit support			X
RPS Compliance			
Tier 1 RECs (from renewable generators or REC brokers)	X		X
Tier 2 RECs (no longer needed post 2019)			
SRECs (from qualifying solar projects or SREC brokers)	X		X
Alternate Compliance Payments (to DC)	As needed		As needed
Transmission			
Network Integration Transmission Service (from PJM)		X	X
Administrative Charges (per SOS tariff)		X	X
Taxes		X	X

Figure 4.3 – Full Requirements Service Structure

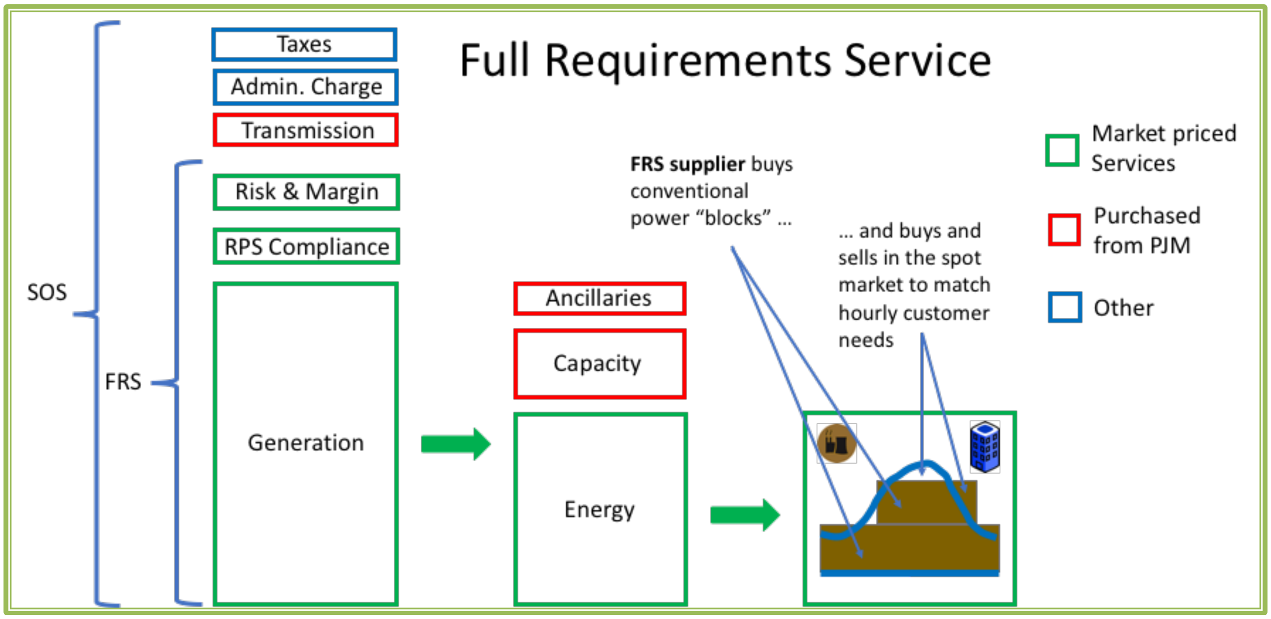
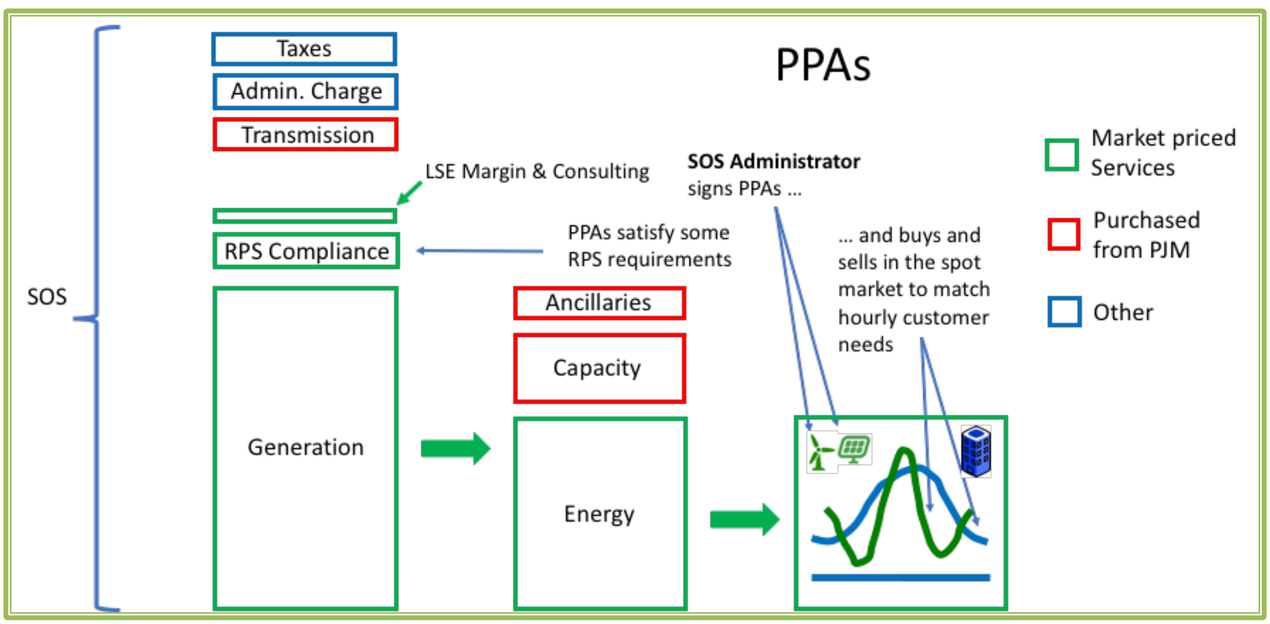


Figure 4.4 – PPA Structure



Managing SOS price variability

As noted above, the current FRS SOS procurement process based on one-year and three-year FRS contracts provides one-year price certainty to all SOS customers and, in the case of residential and small commercial customers, three-year price smoothing. A key question to be answered in adopting a PPA approach is how much price variability might be experienced in SOS costs and how cost variability would be translated into retail SOS prices.

<u>One-year price stability</u>

In the PPA strategy, SOS supply costs will vary month-to-month based largely on the volumes of wholesale spot-market purchases and sales required, and on the costs of those purchases and sales. Annual adjustments to capacity charges, variations in ancillary services costs, and minor adjustments to transmission charges can also affect month-to-month supply costs.

Retail prices to SOS customers can be fixed for months at a time through the use of tracking accounts and true-up mechanisms.

How and when these month-to-month supply cost variations are translated into changes in retail prices to SOS customers will need to be determined in the detailed design of the new SOS framework. It is not necessary for monthly variations in costs to be translated into monthly changes in retail prices to SOS customers. Prices can be established for SOS customers for defined periods of time, seasonally or annually for example, and the SOS Administrator can accumulate any over-charges or under-collections relative to costs in a ‘tracking account”. A “true-up” charge is then included in rates for a subsequent period(s) to clear the tracking account. The District’s Department of General Services uses this method to bill accounts for which it purchases electricity . Billing rates are periodically set for its various accounts, and its retail supplier accumulates the over-runs and under-runs into a true-up charge.

While further analysis is needed to estimate the likely range of tracking account balances that might be experienced, as shown in Table 4.2 below, D.C. SOS customers have already experienced seasonal price swings as large as 3.5 cents per kWh from season to season, and routinely see seasonal swings of 1/2 cent per kWh. The new PPA strategy should be manageable within those historical precedents.

Year-to-year price stability

> The year-to-year price variability of SOS in a PPA purchasing strategy should be comparable to that of the FRS purchasing strategy currently in use.

Year-to-year changes in spot market energy prices are the main driver of year-to-year SOS price variability in a PPA approach. Lesser contributors are variations in year-to-year capacity costs, fluctuations in ancillary services costs and changes in RPS compliance costs.

Table 4.2 shows residential SOS prices from 2005 to 2017 and computes an average annual SOS price based on 50% summer / 50% winter prices. In absolute value, year-to-year price variations were as little as $.65 per MWH and as much as $14.85 per MWH, with an average year-to-year variation of $6.49 per MWH and a standard deviation in the year-to-year value of +/- $4.60 per MWH. In approximate terms, therefore, SOS has varied on average approximately one-half cent per kWh year-to-year, with the largest difference being 1.5 cents per kWh.

Table 4.2 – Year-to-Year SOS Price Variations

Historic Residential SOS Prices ($/MWH)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Summer (cents per kWh)	7.05	8.34	9.48	11.23	11.57	11.49	10.05	9.14	9.61	8.29	8.64	8.05	7.62
Winter (cents per kWh)	6.66	6.66	7.71	8.93	10.82	11.11	11.10	9.63	9.03	9.70	8.29	8.70	8.29
Estimated Annual SOS (50/50)	$68.55	$75.00	$85.95	$100.80	$111.95	$113.00	$105.75	$93.85	$93.20	$89.95	$84.65	$83.75	$79.55
Absolute value of change from prior year		$6.45	$10.95	$14.85	$11.15	$1.05	$7.25	$11.90	$0.65	$3.25	$5.30	$0.90	$4.20
												Avg.	$6.49
												S.Dev	$4.60

To estimate the year-to-year variability in SOS costs using a PPA strategy, the total annual differential between renewable power energy production value and SOS residential customer energy costs was computed using actual PJM market prices for energy from 2006 to 2017. Year-to-year changes in this differential are the main driver of year-to-year cost variability for the PPA approach.

The following assumptions were made in this computation:

- all SOS residential energy requirements are purchased at hourly spot market prices in the Pepco load zone;
- a 50/50 portfolio of solar/wind PPAs is purchased to match the annual kWh SOS requirements;
- all renewable power production is sold into the hourly spot market: solar at the Dominion Hub, and wind power in the Northern Illinois Hub.

This analysis captures

- the volume differences between the hourly renewable power production profiles and the hourly SOS customer load requirements,
- differences in energy prices between the times of peak renewable production and peak SOS customer requirements, and
- pricing differences between the production locations and the District.

Table 4.3 shows the annual costs of energy to serve residential SOS requirements less the value of the 50/50 wind/solar production based on the assumptions above. In absolute value, year-to-year price variations were as little as $.85 per MWH and as much as $11.42 per MWH, with an average year-to-year variation of $5.18 per MWH and a standard deviation in the year to year value of +/- $3.27 per MWH. These year-to-year variations are slightly smaller than those tabulated above for SOS service over the past 11 years. It would appear from this analysis that the PPA strategy can be expected to achieve equivalent year-to-year price stability to the current FRS strategy.

Table 4.3 – Year-to-Year Variability of Renewable Production Value Less Residential Load

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy Cost of Residential Load												
Weighted LMP - Load Pepco Zone	$ 65.81	$ 76.56	$ 89.44	$ 45.37	$ 58.50	$ 52.23	$ 39.90	$ 43.46	$ 64.18	$ 43.27	$ 34.67	$ 34.01
Energy Value of Solar Generation												
Weighted LMP - Solar Production Dominion Hub	$ 66.28	$ 76.22	$ 89.20	$ 41.80	$ 58.25	$ 54.16	$ 40.23	$ 42.43	$ 51.94	$ 39.35	$ 33.16	$ 34.21
Energy Value of Wind Generation												
N Illinois Hub												
Weighted LMP - Wind Production N Illinois Hub	$ 40.11	$ 44.44	$ 47.58	$ 29.69	$ 31.48	$ 31.40	$ 27.59	$ 30.82	$ 41.27	$ 28.32	$ 24.83	$ 26.43
Load Cost less 50% Solar / 50% Wind Generation Value	$ 12.62	$ 16.23	$ 21.05	$ 9.63	$ 13.63	$ 9.46	$ 5.99	$ 6.84	$ 17.57	$ 9.44	$ 5.68	$ 3.69
PPA Year-to-Year Change (absolute value)		$ 3.61	$ 4.82	$ 11.42	$ 4.01	$ 4.18	$ 3.47	$ 0.85	$ 10.74	$ 8.14	$ 3.76	$ 1.99
											AVG	$ 5.18
											STDEV	$ 3.27

Long-term stability

The current SOS structure does not provide long-term price stability nor long-term protection against rising power prices, rather it tracks conventional power pricing trends in the PJM electricity market. PPAs provide a new opportunity to achieve that stability and protection.

> The current SOS structure tracks conventional power pricing trends. PPAs provide a new opportunity to achieve long-term price stability.

As the analysis of historical data in Table 4.3 shows, the value of renewable generation should track the cost of the needed SOS supply within a band of variability. For this reason, PPAs should act as a good "hedge" against future power price increases. As shown in Appendix 3, Table A3-1 in this study, conventional power prices are expected to rise in nominal terms over time.

Note that if conventional power prices fall over some period of time, SOS prices will not follow them downward if long-term PPAs are in place, but rather will remain stable.

REC Prices

The focus of the foregoing analysis has been on energy prices in the PJM power market since they are the largest drivers of electricity cost variability. As detailed in Table A3.1 and the accompanying citations in Appendix 3, the analysis in this study presumes that Tier 1 REC prices will remain stable in the future. No additional cost stabilization benefits, therefore, have been attributed to the fact that the PPA contracts analyzed in this study include RECs. Should Tier 1 REC prices rise at any point in the future, however, the PPA contracts will provide protection against those increases.

Transitioning from FRS to PPAs

The statutory language establishing SOS appears, in its current form, to support a transition to the PPA approach. The DCPSC is given broad latitude under § 34–1509 to develop SOS procurement details. It will be necessary, however, to undertake formal rulemakings to transition SOS from FRS to PPAs since many details of the FRS procurement process are prescribed in regulations. Revised procurement and rate setting processes by Pepco as SOS Administrator, and revised approval and review processes at the DCPSC would also be required including:

1. Retail price setting - Under the current FRS SOS structure, wholesale bid prices are quoted to align with the seasonal and time-of-use characteristics of the various rate schedules. In a PPA structure, costs from an aggregated electricity portfolio would need to be properly allocated to each customer class, and each seasonal and time-of-use category would have to be computed.

2. Procurement processes - A procurement process tailored to the ongoing management of the PPA strategy, including bidding procedures for the PPAs and the procurement of other components of electricity supply, needs to be developed to replace the annual FRS procurements. Management of the PPA strategy could involve creating an energy management policy document or "risk management document" that sets guidelines for the purchasing program. The document would outline the boundaries of the purchasing decisions than can be made routinely by the SOS Administrator, reporting requirements, SOS retail price setting methods, etc.[56]

3. Approval and review processes - A revised process of SOS procurement review and approval would need to be implemented that recognizes the multi-component purchasing needed to support the PPA structure.

Administrative Charges

New procurement processes may require revisions to the Administrative Charge component of SOS. Appendix 6 provides details on the current structure of the Administrative Charge.[57] Total Administrative Charges across all SOS customer groups are estimated to be between $10 million and $11 million for 2018/2019 under the current FRS procurement model.

As described more fully in Appendix 6, the Administrative Charge is comprised of the following components:

- Incremental costs
- Uncollectibles less late payment charges
- Cash working capital costs
- SOS Administrator margin
- Adder

Incremental costs are those specifically associated with executing the SOS bidding process and managing the SOS program. In total, incremental costs for the 2018/2019 period are expected to be slightly less than $1,000,000 to manage the FRS procurement process.

The relative costs of managing a PPA structure will depend on a number of factors including a different scope to consulting services, different responsibilities for the SOS Administrator, and the scope and extent of on-going Commission review.

- CRI estimates, based on the experience of the principal investigator for this report, that consulting fees to manage an annual PPA procurement process would likely be in the range of $200,000 to $300,000. Note that these expenses would be incurred only in those years in

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[56] The Eastern Shore of Maryland Educational Consortium Energy Trust (ESMEC-ET) has been operating under a "Block & Index" structure based on conventional energy purchasing, for a number of years. The Consortium's website provides links to a number of its procurement management documents. See the "Agreements, Policies, Guidelines, and Strategies" link at http://www.esmec.org/EnergyTrust.html

[57] The biennial review of SOS recently docketed by the DCPSC will be examining key components of the Administrative Charge. See Order 19431, August 9, 2018.

which procurements are conducted, which could be as few as three years depending on the chosen "ramp rate".

- CRI estimates that annual consulting fees to assist with the on-going management of the PPA strategy (e.g. the size and timing of conventional power block purchases, the incorporation of other risk management tools) could range from $100,000 to $300,000 per year.

Cash working capital costs, currently projected to be $1 million per year, may need to be reevaluated to the extent that the timing of payments to PPA providers, to block power providers and to PJM directly differ in timing from current payments to FRS suppliers.

The SOS Administrator margin, at approximately $6 million per year, is the largest component of the Administrative Charge. The charge is intended to, "…fully compensate PEPCO for the risk, including lost opportunity costs, it is incurring as the SOS provider."[58] It is not clear what effect a transition to a PPA strategy might have on an appropriate SOS Administrator margin. Note that the amount of this margin is to be reviewed in the DCPSC's recently docketed biennial SOS review.[59]

The adder component of Administrative costs is a "plug" that brings the total level of the Administrative Charge to a Commission approved overall figure. Establishing an appropriate total level of Administrative Charge was viewed as important to establishing a fair competitive market at the outset of electric competition. For 2018/2019, the total adder across all customer classes is projected to be approximately $2,000,000. To the extent that costs in other categories (e.g. incremental costs, cash working capital) increase or decrease under the PPA structure, some or all of these increases or decreases may be absorbed as an adjustment to the adder with no effect on the total Administrative Charge. As with the SOS Administrator margin, the adder is being reviewed in the recently docketed biennial SOS review.[60]

Timeline

In addition to establishing the new regulations, procedures and processes needed to support the PPA strategy, the new SOS process would need to be phased in. The three-year FRS contracts that are a part of the present residential SOS supply imply that a minimum three-year transition would be needed.

Figure 4.5 illustrates a potential phase-in plan based on the Ramp Rate #1 scenario described in Section 3 of this report. As shown in Figure 4.5, a 2019 SOS procurement could include a two-year supply for residential and small commercial customers instead of a three-year supply, and the 2020 procurement a single year supply. This brings all FRS contracts to closure by mid-2021, allowing the transition to the PPA approach.

As PPA volumes are ramping up, conventional power blocks are purchased to stabilize SOS costs. These blocks are purchased in advance to create a laddering similar to the current FRS contracts. Ultimately, the PPAs provide price stability.

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[58] Order 13268 paragraph 65
[59] Order 19431 pp. 2 - 3
[60] Ibid pp. 3 - 4

Figure 4.5 presents one of many possible phase-in plans. A longer ramp rate would create a more graduated phase in. A higher ultimate PPA percentage target would decrease spot purchases. This detailed plan should be developed as part of regulatory proceedings.

Figure 4.5 – FRS to PPA Transition Example

Transition Timeline	6-1-18 to 5-31-19	6-1-19 to 5-31-20	6-1-20 to 5-31-21	6-1-21 to 5-31-22	6-1-22 to 5-31-23	6-1-23 to 5-31-24	
All figures in MWH/yr.	2018/2019	2019/2020	2020/2011	2021/2022	2022/2023	2023/2024	
SOS Requirements							
Residential	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	
Commercial	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	
Total	2,800,000	2,800,000	2,800,000	2,800,000	2,800,000	2,800,000	
FRS Contracts							
Residential							
2016 Contracts	600,000						
2017 Contracts	600,000	600,000					
2018 Contracts	600,000	600,000	600,000				
2019 Contracts		600,000	600,000				
2020 Contracts			600,000				
Commercial							
2018 Contracts	1,000,000						
2019 Contracts		1,000,000					
2020 Contracts			1,000,000				
FRS Volumes Delivered	2,800,000	2,800,000	2,800,000				
PPAs							
2019 Contracts				650,000	650,000	650,000	
2020 Contracts					650,000	650,000	
2021 Contracts						650,000	
Total				650,000	1,300,000	1,950,000	70%
Conventional Block Purchases							
2019 Contracts				430,000			
2020 Contracts				430,000	210,000		
2021 Contracts				440,000	220,000		
2022 Contracts					220,000		
Total				1,300,000	650,000	-	
Spot Market Purchases				850,000	850,000	850,000	30%
PPA/Block/Spot Volumes Delivered				2,800,000	2,800,000	2,800,000	

Other Issues

In the recently docketed biennial review of SOS, the DCPSC listed eleven questions it sought comments on relate to the use of PPAs as part of SOS procurement. This study provides detailed information that is responsive to many of these questions, but a few questions point to important considerations that are beyond the scope of this study, namely the impact on retail competition for electricity supply, impact on Pepco's credit worthiness, and whether SOS PPAs may be deemed to be "out-of-market" subsidies by FERC with implications to the capacity price of renewable generation.[61]:

[61] Order 19431 pp. 6 – 7

5 – CONCLUSIONS AND RECOMMENDATIONS

Conclusions

The information and analysis presented in this study point to an overall conclusion that adopting a new strategy for the District's SOS supply, one based on procuring electric energy and RECs under bundled PPA contracts, is feasible.

1. Sufficient supplies of renewable energy are available in PJM states. At the present time there are a large number of wind and solar projects under development in the region that could supply SOS requirement, and EIA forecasts continued development of renewable energy on a nationwide basis. PPAs with existing wind power projects in the region could also be tapped.

2. PPA prices offered by selected new wind and solar projects can produce lower SOS prices. A sample of prices being offered today indicates that some renewable supplies are available at or below current and projected conventional power costs. This is especially true for new solar projects under development in Virginia. SOS cost modeling based on various portfolios of the best priced wind and solar projects show the opportunity for SOS costs to be lower under the PPA model than under continued conventional purchases. Projected cost declines for solar and wind power systems, while offset by pending reductions and expirations of federal tax incentives, point toward continued availability of attractively priced renewable energy.

3. A shift in SOS purchasing strategy is needed to support PPAs. A shift away from the current FRS purchasing strategy best supports incorporating PPAs into the SOS supply. The PPA strategy would require the SOS Administrator to acquire all other required electricity supply components including capacity, ancillary services, etc.

4. The variability of retail prices to SOS customers under the PPA strategy should be no more than the historical price variability of SOS. The PPA strategy can be structured to provide near-term pricing certainty and year-to-year price stability similar to that currently provided by the FRS strategy, and it offers long-term price stability that is not offered by the current approach.

5. Renewable energy could begin to flow as early as 2021/2022. Presuming most supply will come from new wind and solar projects, construction will generally take two to three years from the time PPAs are signed. This time frame meshes with the roll off of 3-year FRS contracts that are part of the current SOS portfolio.

6. A phase-in period of a few to several years provides access to large, economic projects. The phase in of PPAs affects the annual volume of PPA purchases. Access to large, cost-competitive wind power projects is best achieved with a 3-year to 6-year ramp rate.

Recommendations

While this study has sought to be thorough in presenting and investigating a full range of issues relating to the feasibility of this SOS transition, the path forward is clearly complex and the PPA strategy will need further validation as it moves toward implementation. In addition, market conditions are subject to change.

5. Further validation of project availability and pricing should be undertaken. The inventories of projects under development and the sample pricing offers used in this study are from reliable sources, but further validation is needed. This could be accomplished through a Request for Information process seeking "indicative offers" to guide the detailed development of PPA procurements.

6. The implications for the role of SOS Administrator should be detailed. The implications of entering into long-term PPA contracts, and of managing a new procurement process, are significant for the SOS Administrator and should be fully reviewed. The current biennial review phase of the DCPSC FC1017 Docket is a potential venue for this review.

7. Additional stakeholder engagement and review of price stability implications for the new SOS process should be undertaken. This study described a tracking / true-up mechanism for short-term price setting and presented an analysis of year-to-year price stability based on historical PJM hourly pricing data. Management of price stability is of central concern to SOS customers, and further review and validation of this issue is advisable. Note that this further review should also explore the full range of risk management tools and strategies that can be employed beyond the inherent "hedging value" of the PPAs themselves as analyzed in this study.

8. Provide oversight bodies with implementation flexibility. It has been noted throughout this report that the electricity market is subject to significant uncertainties over time. Advances in technology, public policy decisions at all levels of government, global energy market and economic conditions, court decisions, etc. could influence the availability of renewable energy supplies, the pricing of those supplies and the conventional energy market. The oversight bodies tasked with implementing a new SOS strategy should be granted sufficient flexibility in strategy design, phase-in, and approvals to react to the full range of circumstances.

APPENDIX 1

SURVEY OF RENEWABLE ENERGY PROCUREMENT PRACTICES

This appendix presents brief summaries of the renewable energy procurement practices of a number of government and private entities including:

- default service providers in restructured electric markets,
- municipal aggregators including Community Choice Aggregators (CCAs), and
- large corporate, institutional and government buyers.

The summary relies on public data sources. It is not an exhaustive list of practices and buyers, but rather identifies approaches that are commonly employed by state and local government buyers, and those approaches that are most commonly used to integrate renewable PPAs into broader electricity purchasing needs.

The summary includes the District's SOS procurement practices, and those of the District's Department of General Services.

The survey reveals the following:

- Most default service or SOS providers procure renewable energy to meet state RPS standards but are not adding higher renewable energy content beyond those standards. RPS compliance is generally accomplished through REC purchases, in the short-term market, the long-term market or both, depending on the jurisdiction.

- Municipal aggregators (including Community Choice Aggregators) typically operate in states with restructured electricity markets, and most were initially formed for the purpose of securing low priced power supplies through large scale purchasing. In some instances, however, including Community Choice Aggregation in California, there is growing focus on higher renewable content. This is often accomplished through REC purchases, though there is movement toward bundling electricity supply with RECs.

- Corporations, institutions, and governments (buying supplies for their own buildings) have long histories of purchasing unbundled RECs to achieve aggressive renewable energy purchasing goals, but they have also been the vanguard for purchasing bundled energy supply and RECs under long-term contracts. The District of Columbia Department of General Services is among these leaders.

Default Service Providers

DC – The DCPSC produces annual reports on RPS compliance that are rich documents in laying out the prior year's RPS compliance details, including those of Pepco acting as SOS Administrator, and in providing descriptions of the regulatory framework and practices used for RPS compliance.[62]

In its latest RPS report, the DCPSC describes the current RPS compliance procurement approach and the underlying regulatory framework in this way:

> "The RPS rules state that the local electric distribution company may recover prudently incurred RPS compliance costs, including REC purchases and any compliance fees, through a non-bypassable surcharge on customers' bills pursuant to Commission rule 2904 and D.C. Code § 34-1435 (2014 Supp.) Pepco, as the Standard Offer Service ("SOS") Administrator, has never sought to recover RPS compliance costs for SOS through a non-bypassable surcharge on customers' bills. Instead, **winning SOS suppliers bid a full requirements product that includes all costs (including RPS costs)** – other than transmission and distribution costs which are tariffed costs." [emphasis added] [63]

MD – Maryland investor owned utilities follow the same approach to securing renewable energy for SOS as does DC – full requirements service including RPS requirements is procured from wholesale bidders. At this time, there are no long-term procurements of RECs by the utilities supporting SOS.

DE – Delaware's investor owned utility, Delmarva Power, procures renewable energy credits directly to cover the RPS obligations associated with *all* energy distributed in Delaware. These procurements are managed separately from Delmarva's SOS procurements.

Delmarva purchases RECs under long-term contracts and spot contracts for non-solar compliance.[64] With regard to SRECs to satisfy the solar carve-out in the Delaware RPS, Delmarva carries out annual auctions.[65] The Delaware Sustainable Energy Utility acts as a "bank" for certain SREC purchases.

PA – Pennsylvania investor owned utilities follow an approach similar to the approach used in DC and MD, by including some, ***but not all,*** Alternative Energy Portfolio Standard (AEPS) requirements in full requirements wholesale bids. PECO, for example, provides some Tier 1

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[62] See the "Report on the Renewable Energy Portfolio Standard for Compliance Year 2017", May 1, 2018. It is available, along with reports from prior years on the DCPSC website under the "Orders, Reports and Regulations" tab.
[63] Public Service Commission of the District of Columbia "Report on the Renewable Energy Portfolio Standard for Compliance Year 2017", May 1, 2018, pp. 7, 8
[64] See Delmarva Power's "2016-2017 Annual Supplier Renewable Energy Portfolio Standard (RPS) Report Pursuant to Delaware Code Title 26 Subchapter III-A", September 26.2017 https://depsc.delaware.gov/wp-content/uploads/sites/54/2017/10/DPL-DE-RPS-2016-2017-pt1.pdf
[65] Details on the annual auction process can be found at https://www.srecdelaware.com

Solar Alternative Energy Credits (AECs)[66], while First Energy utilities provide varying packages of AECs across their four utility operating companies[67].

IL – Default service in Illinois is procured by the Illinois Power Agency (IPA), an entity set up expressly to perform this procurement role. In April 2018, in response to the passage of the State's Future Energy Jobs Act in 2017, the forward-going method for complying with Illinois' renewable energy mandates is being completely revised. Going forward, IPA will be responsible for conducting procurements to cover all of the State's RPS obligations, not only default service obligations.[68] IPA had procured 20-year, bundled energy plus REC contracts to fulfill RPS requirements for default service customers in the past, but continued procurements were hampered by load defection to competitive supply.[69] Going forward IPA will be procuring long-term REC-only contracts to meet its enlarged RPS obligations.[70] Significant quantities of RECs must be secured from new wind and solar projects[71], and the rules for considering projects in adjacent states to Illinois are complex.

Municipal Aggregators / CCAs

In certain states with restructured electricity markets, cities, counties and other jurisdictions execute procurement programs for residential, commercial and institutional end users within their boundaries. These programs may be offered on an "opt in" basis, with each end user affirmatively choosing to participate, or on an "opt out" basis, with all customers in the jurisdiction required to participate unless affirmatively choosing not to.

Table A1-1[72] - Legal Authorities for Community Choice Aggregation

Legal Authorization for Community Choice Aggregation[8]			
State	**Year**	**Authorizing Legislation**	**Authorizing Legislation Name**
Massachusetts	1997	M.G.L. ch.93A §1	Utility Restructuring Act of 1997
Ohio	2001	Local Ballot Measure	N/A
California	2002	Assembly Bill 117	N/A
Illinois	2002 (residential)	220 ILCS 5/Art. XVI	Electric Service Customer Choice and Rate Relief Law of 1997
New Jersey	2003	Assembly Bill 2165	Government Energy Aggregation Act of 2003
New York	2016	PSC Case 14-M-0224	Order Authorizing Framework for Community Choice Aggregation Opt-Out Program
Rhode Island	1996	RIPUC No. 8124	Utility Restructuring Act of 1996

66 PECO Bidder Information Session DSP IV March 2018 Solicitation February 9, 2018 http://www.pecoprocurement.com/assets/files/PECO_DSP%20IV_March%202018_Webcast_Mar%206.pdf
67 First Energy PA Default Service Program (DSP IV) https://www.firstenergycorp.com/content/fecorp/upp/pa/power_procurements/pa-default-service-program-iv.html
68 Illinois Power Authority, "Long-Term Renewable Resources Procurement Plan", August 6, 2018, p.2
69 Ibid. p.6
70 Ibid. p. 11
71 Ibid. p. 27
72 Table presented in "Community Choice Aggregation" article on Wikipedia, compiled from data from the Local Aggregation Network. http://www.leanenergyus.org/cca-by-state/

Massachusetts

The Cape Light Compact, serving Cape Cod and Martha's Vineyard, was the first CCA to launch in the U.S.[73] A study by the University of New Hampshire Sustainability Institute indicates that CCAs offering higher renewable energy content in the State generally do so by adding additional REC purchases, though some are working to target funding of local renewables.[74]

In October 2017, the City of Boston voted to authorize the establishment of a municipal energy aggregation program.[75] The program is in the early stages of development.

California

CCAs were initially enabled by California Assembly Bill 117 passed in 2002. Marin County Energy (MCE) became the first operating CCA in 2010.

A number of CCAs have recently become operational or are about to become operational across the State. The California Community Choice Association website provides an interactive map with status information and links to specific programs.[76]

The PG&E website has links to ten programs in northern California.[77] All are focused on providing electricity supplies with high renewable energy content, and all are structured on an "opt out" basis. Customers who opt out receive generation supplies from PG&E.

California CCAs have relied on a variety of sourcing strategies to meet goals of increased renewable energy content, or of offering high renewable content products. These strategies span the purchase of RECs from diverse sources, to bundled purchases of RECs and power from operating projects on a short-term basis, to long-term bundled purchases. A 2017 study by Sean F. Kennedy of UCLA surveys the practices of a number of CCAs.[78]

As an example of a California CCA program, CleanPowerSF offers two energy supply options, a 43% renewable supply and a 100% renewable supply.[79] These compare to the current PG&E utility content of 33%.[80] The 43% renewable supply product is described as being cost competitive with PG&E's standard service[81], with the 100% renewable supply priced

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[73] Community Choice Aggregation (CCA) in Massachusetts, Gabrielle R. Lichtenstein & Indiana Reid-Shaw, University of New Hampshire Sustainability Institute, p. 10
[74] Ibid
[75] https://www.boston.gov/news/council-votes-authorize-community-choice-energy
[76] https://cal-cca.org/#top
[77] https://www.pge.com/en_US/residential/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/community-choice-aggregation.page
[78] "'Greening' the Mix through Community Choice", Sean F. Kennedy, UCLA, June 2017 https://www.ioes.ucla.edu/wp-content/uploads/Community-Choice-Aggregation_final-June-2017.pdf
[79] https://cleanpowersf-sfpuc-yem2.squarespace.com
[80] https://cleanpowersf-sfpuc-yem2.squarespace.com
[81] https://cleanpowersf-sfpuc-yem2.squarespace.com/

approximately 1.5 cents per kWh higher.[82] Note that PG&E offers "PG&E Solar Choice", a 100% solar product that is priced similarly to the 100% renewable CleanPowerSF offering.[83]

In July 2018 most of the City's commercial accounts are to be automatically enrolled in the program, and residential customers will be enrolled in early 2019.[84] San Francisco's goal is to reach 100% carbon free energy by 2030.[85]

A recent press release notes that CleanPowerSF has entered into PPAs with new solar and wind projects.[86]

New York

New York State initiated its path toward CCAs as part of its broader Reforming the Energy Vision (REV) process. CCAs can be formed by towns, cities and municipalities, but not by county governments.

Launched in May 2016, Westchester Power is the first CCA approved by the NY Public Service Commission. The CCA provides a 100% renewable supply as well as a basic service. The 100% green supply is based on the inclusion of 100% Green-e certified national RECs.[87] The CCA recently reported the start of its community solar initiative.[88]

Corporate, Institutional and Other Government Buyers

Large corporate buyers, many in the energy intensive data center industry, institutional buyers such as colleges and universities, and government buyers at the federal, state and local levels, have been in the vanguard of purchasing renewable energy from large, grid connected power projects. In many cases these purchasers have elected to buy large percentages of their electricity from renewables and have effectively integrated these purchases into their overall electricity purchasing programs. Below are descriptions of important purchases in the Mid-Atlantic region.

District of Columbia Department of General Services

In 2015, DCDGS signed the largest wind power PPE ever by a U.S. municipality at that time, providing an estimated 30 – 35% of the electricity needs of the DCDGS building portfolio.[89] The purchase is for the full output of a 46 MW project in Pennsylvania for 20 years, and is estimated to supply 120,000 to 150,000 MWH per year. The project was in operation at the time of the DCDGS RFP, becoming fully operational in 2011. The project is located in the PJM footprint.

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[82] https://cleanpowersf-sfpuc-yem2.squarespace.com/enroll
[83] https://cleanpowersf-sfpuc-yem2.squarespace.com/business
[84] https://cleanpowersf-sfpuc-yem2.squarespace.com/enroll
[85] https://cleanpowersf-sfpuc-yem2.squarespace.com/enroll
[86] June 6, 2018 https://www.cleanpowersf.org/news/
[87] http://www.westchesterpower.org/constellation-environmental-disclosure-letter-wp-green-power/
[88] http://www.westchesterpower.org/sustainable-westchester-launches-community-solar-program/
[89] https://dgs.dc.gov/page/renewables-energy-purchasing

General Services Administration

The U.S. General Services Administration signed a 75 MW solar PPA with the Great Bay Solar Facility in Somerset County Maryland. The project began commercial operation in March 2018.

George Washington University, George Washington University Hospital and American University

In 2014, the George Washington University, American University and the George Washington University Hospital signed a PPA with a 52 MW solar project in North Carolina. The project is located in the PJM footprint.

University of Maryland

The University of Maryland was an early adopter of long-term wind power purchases including purchases from the Roth Rock North Wind farm and the Pinnacle Wind Farm. Both projects became operational in 2011/2012.

Amazon Web Services, Microsoft, Facebook

Over the past three years, companies either already operating or planning large data centers in Virginia have entered into commitments of various structures to source solar power from new projects.

- Amazon Web Services has signed multiple PPAs totaling 260 MW.[90] Indications are that these are bundled PPAs for electric power and RECs.
- Facebook, as part of its plans to build a new data center in suburban Richmond announced that it will enter an agreement with Dominion Energy to supply power to the data center from a new solar farm in the Commonwealth. Details are still under development, but Facebook will be buying project RECs while Dominion retains the electric power as part of its utility supply.
- Microsoft recently announced plans for a 315 MW solar purchase.

[90] https://aws.amazon.com/about-aws/sustainability/

APPENDIX 2

SOURCING ALTERNATIVES

Throughout this study, renewable energy sourcing has been focused on wind and solar projects located in the PJM states. Wind and solar will represent the vast majority of purchasing opportunities, and both are eligible resources in the current D.C. RPS. As has been shown, the PJM states offer a significant volume of projects at attractive prices at this time.

This appendix provides an in-depth review of renewable energy sourcing as background for any future discussions on alternatives that may arise. It is possible, for example, that other renewable resources may wish to bid for a portion of the SOS requirement.

Three dimensions of sourcing affect PPA pricing and availability:

- Resource eligibility
- Generator location
- Generator vintage

Through its requirements, the District's Renewable Portfolio Standard (DC RPS) encourages the development of renewable electric generation that meets certain definitions for all three of these dimensions. Alternative definitions, however, are used by others and the information below reviews a number of established alternative standards.

Resource eligibility

The DC RPS defines Tier 1 and Tier 2 sources of renewable energy.[91] Tier 1 includes solar, wind, qualifying biomass, certain methane sources, geothermal, ocean, fuels cells operated on Tier 1 biomass and methane sources, and certain processes involving the use of waste water. Tier 2 resources include hydroelectric power, waste-to-energy[92], and certain biomass sources not qualifying for Tier 1. Solar energy systems meeting certain requirements satisfy the solar energy "carve-out" of the District's RPS[93], while solar energy systems that do not meet those requirements are eligible Tier 1 resources.[94] Note that 2019 is the last year in which the DC RPS will include a Tier 2 requirement, so those sources will no longer be part of the DC RPS.

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[91] Code of the District of Columbia, Title 34 Public Utilities, Chapter 14A Renewable Energy Portfolio Standard, Section 34-1431. Definitions (15) and (16)

[92] Note that its inclusion in this definition notwithstanding, the incineration of solid waste was disqualified as an eligible technology at the end of 2012. Code of the District of Columbia Title 34 Public Utilities Chapter 14A. Renewable Energy Portfolio Standard, Section 34-1433 Renewable energy credits (g)(2)

[93] Code of the District of Columbia Title 34 Public Utilities Chapter 14A. Renewable Energy Portfolio Standard, Section 34-1432(e)(1)

[94] Ibid Section 34-1432(e)(2)

Two broadly accepted standards for renewable energy resource eligibility are:

- US EPA ("Green Power")
- Green-e

The District of Columbia Government participates in the US EPA's Green Power Partnership which is based on the US EPA Green Power definition. [95]

Table A2-1 compares the eligible resources under the DC RPS Tier 1 to those in the other two standards.

Table A2-1 – Renewable Resource Eligibility Comparison

Resource	DC RPS Tier 1	US EPA Green Power[96]	Green-e[97]
Solar photovoltaic	X	X	X
Solar thermal	X		
Wind	X	X	X
Biomass	X	X	X
Co-firing	X	X	X
Landfill & Wastewater Methane	X	X	X
Geothermal	X	X	X
Ocean	X		X
Fuel cells using qualifying res.	X	X	
Certain wastewater technology	X		
Hydropower		X	X
Bio-diesel generators		X	X
CHP using qualifying resources		X	
Black liquor		X	

The comparison of these standards suggests that the District could consider additional sources of renewable energy while remaining within broadly accepted standards, should it appear valuable. In particular *certain* hydropower resources, bio-diesel generators, and alternative forms of qualifying biomass are accepted under both the US EPA and Green-e definitions.

The full definitions of eligible hydropower in the US EPA and Green-e definitions are lengthy but are much more restrictive than the DC RPS Tier 2 definition. They are generally limited to

[95] The District ranks third in total renewable energy purchases among local governments in the US EPA's Green Power Partnership rankings and 20th among all green power purchasers when corporations and federal government agencies are included.
[96] EPA's Green Power Partnership Requirements, U.S. Environmental Protection Agency, September 2017 Appendix A https://www.epa.gov/sites/production/files/2016-01/documents/gpp_partnership_reqs.pdf
[97] Green-e Renewable Energy Standard for Canada and the United States, Version 3.1, June 9, 2017 Center for Resource Solutions pp. 3-7 https://www.green-e.org/docs/energy/Green-e%20Standard%20v3.1%20US.pdf

so-called “low impact” hydropower. The alternate definitions of qualifying biomass are similarly lengthy.

The comparison of standards also shows that the District includes two resources not eligible in the other two standards, solar thermal and certain waste water technologies. Solar thermal, while relevant to the District’s solar “carve out”, is clearly not relevant to long-term PPAs for electricity supply. Waste water, as defined, may provide a minor sourcing opportunity.

As discussed below, if additional sources of renewable energy are added, consideration should be given to the ability to identify and track eligible projects through the generation attribute reporting and tracking systems in place across the U.S.   Regional tracking systems vary in the level of granularity they provide in distinguishing among different forms of renewable energy (e.g. solar vs. wind vs. hydropower), and in the ways they track projects eligible under the various state RPS programs.   Some systems may not support tracking output of the types of generators that meet the requirements of the DC RPS, the US EPA or Green-e, and may therefore constrain consideration of certain generators in certain locations. The District could develop its own generator identification and monitoring processes, but this could be burdensome.   Figure A2.1 shows the various tracking systems in place across the nation.

Figure A2-1 – Map of Renewable Energy Tracking Systems

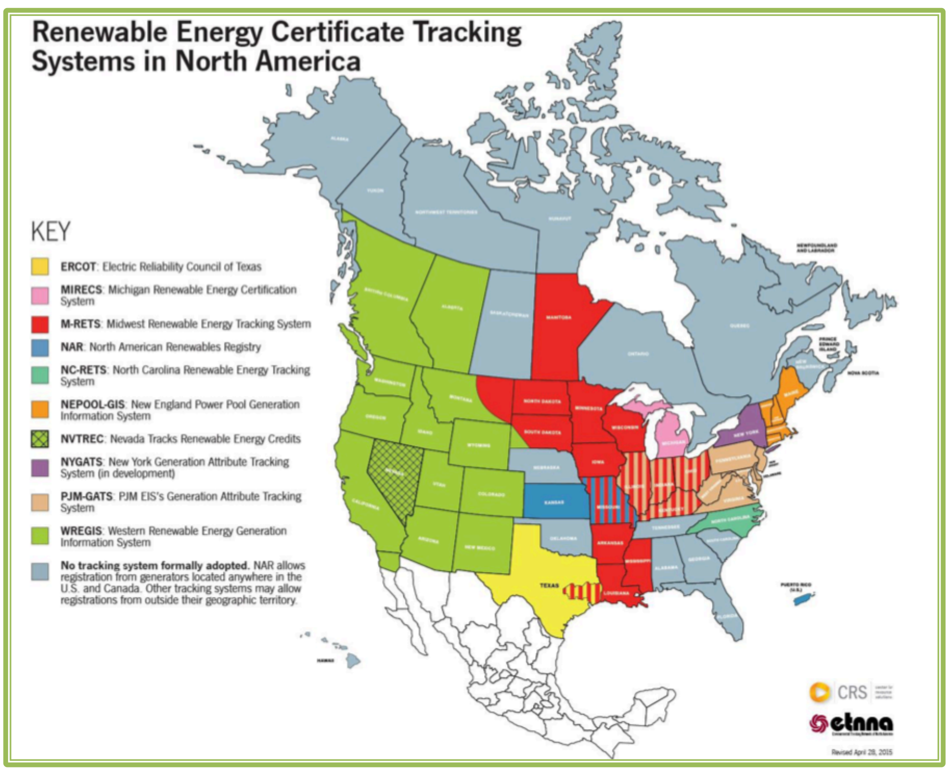

Illustration source – Center for Resource Solutions[98]

[98] “Renewable Energy Certificate Tracking Systems” Jennifer Martin, Executive Director, Center for Resource Solutions, April 30, 2015 https://www.epa.gov/sites/production/files/2016-01/documents/webinar_20150430_martin.pdf

Generator location

The DC RPS allows RECs to be sourced from a geographic area defined as follows:

> " "Renewable energy credit" or "credit" means a credit representing one megawatt-hour of energy produced by a tier one or tier two renewable source located within the PJM Interconnection region or within a state that is adjacent to the PJM Interconnection region." [99]

The PJM Interconnection region covers all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.[100]

The DC Public Service Commission reports, "the following states are currently deemed adjacent to PJM: Alabama, Arkansas, Georgia, Iowa, Mississippi, Missouri, New York, South Carolina, and Wisconsin."[101]

This study has focused on the states in the PJM Interconnection region, as they show adequate sourcing opportunities. Alternative standards that could be considered for geographic eligibility are:

- ICLEI GHG protocol reporting
- US EPA "Green Power"
- Green-e

Table A2-2 compares the eligible locations under the DC RPS Tier 1 to the other three standards.

Table A2-2 – Geographic Sourcing Comparison

Location	DC RPS Tier 1	ICLEI	US EPA Green Power[102]	Green-e[103]
PJM Interconnection				
Partial (RFC East)		X		
Entire PJM footprint	X			
States adjoining PJM	X			
Full U.S.			X	
Full U.S. plus certain imports				X

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[99] Code of the District of Columbia Title 34 Public Utilities Chapter 14A. Renewable Energy Portfolio Standard, Section 34-1431(10)

[100] http://www.pjm.com/about-pjm/who-we-are/territory-served.aspx

[101] Public Service Commission of the District of Columbia, Report on the Renewable Energy Portfolio Standard for Compliance Year 2017, May 1, 2018, p. 20

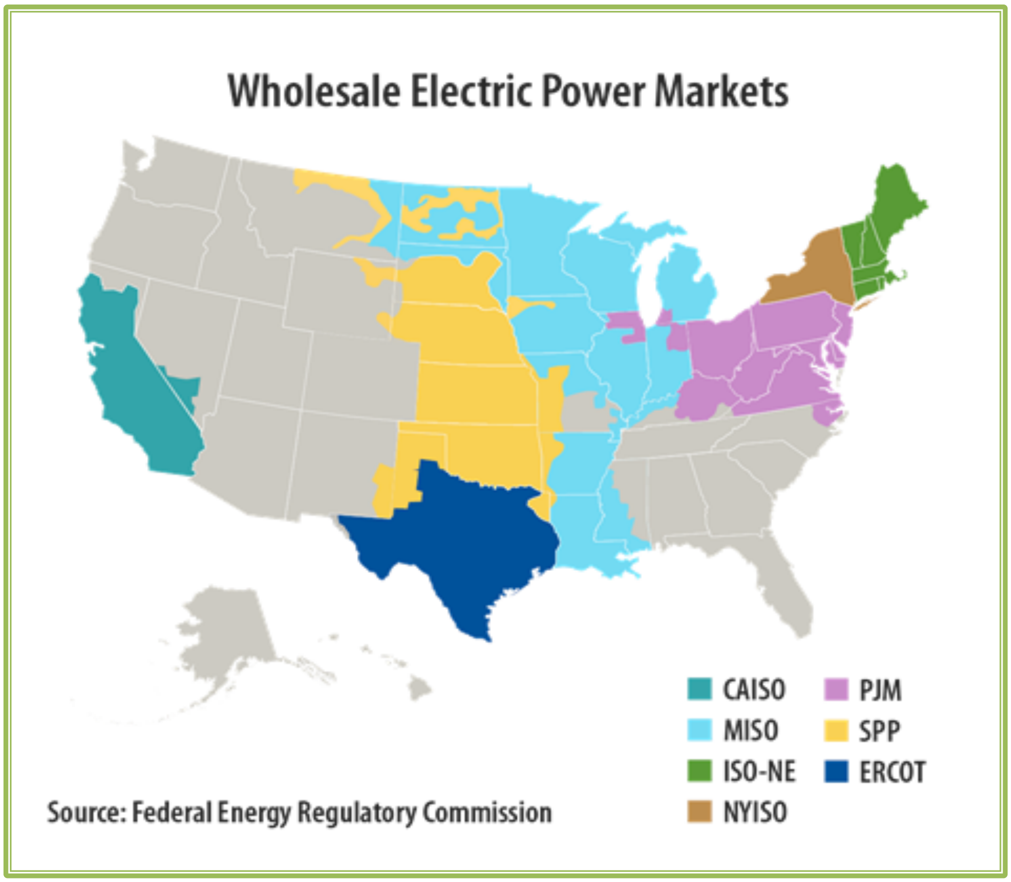
[102] Green Power Partnership Eligible Scope of Green Power Use https://www.epa.gov/greenpower/green-power-partnership-eligible-scope-green-power-use

[103] Green-e Renewable Energy Standard for Canada and the United States, Version 3.2, March 20, 2018, Center for Resource Solutions

In order to assess the possible economic advantage of expanding the geographic sourcing of renewable energy, this study evaluates a PPA purchasing scenario based on the best projects available nationwide in the LevelTen Energy Marketplace. Sourcing from wind and solar projects under development in Texas and Oklahoma represented a potential for lower costs, but not significantly lower. Note that DOEE believes that renewable energy sourced from any U.S. location under a PPA including both energy and renewable energy credits could qualify to reduce the District's GHG emissions under its reporting protocols.

When considering renewable energy sourcing from "any" project in the U.S., it must be kept in mind that a PPA can only be considered from a project located within a functioning wholesale power market. Without such a market, power cannot be sold to a non-utility buyer nor can power be economically valued. Figure A2-2 shows the areas of the U.S. covered by wholesale markets.

Figure A2-2 – U.S. Wholesale Power Markets



Restricting eligible resources to the RFC East region,[104] used by the District's ICLEI protocol to compute the average carbon intensity of electricity used in the District, would place severe restrictions on renewable energy sourcing. As shown in Figure A2-3 all solar power projects in Virginia and in western states would be eliminated from consideration, as would all wind projects west of Pennsylvania. A review of the data presented in Table 2.1 of Section 2 of this report indicates that were sourcing restricted to New Jersey, Pennsylvania, Maryland and Delaware, only 5,500 MW of wind and solar capacity would be available and only half of that representing new projects.

Figure A2-3 – USEPA Emissions Tracking Subregions

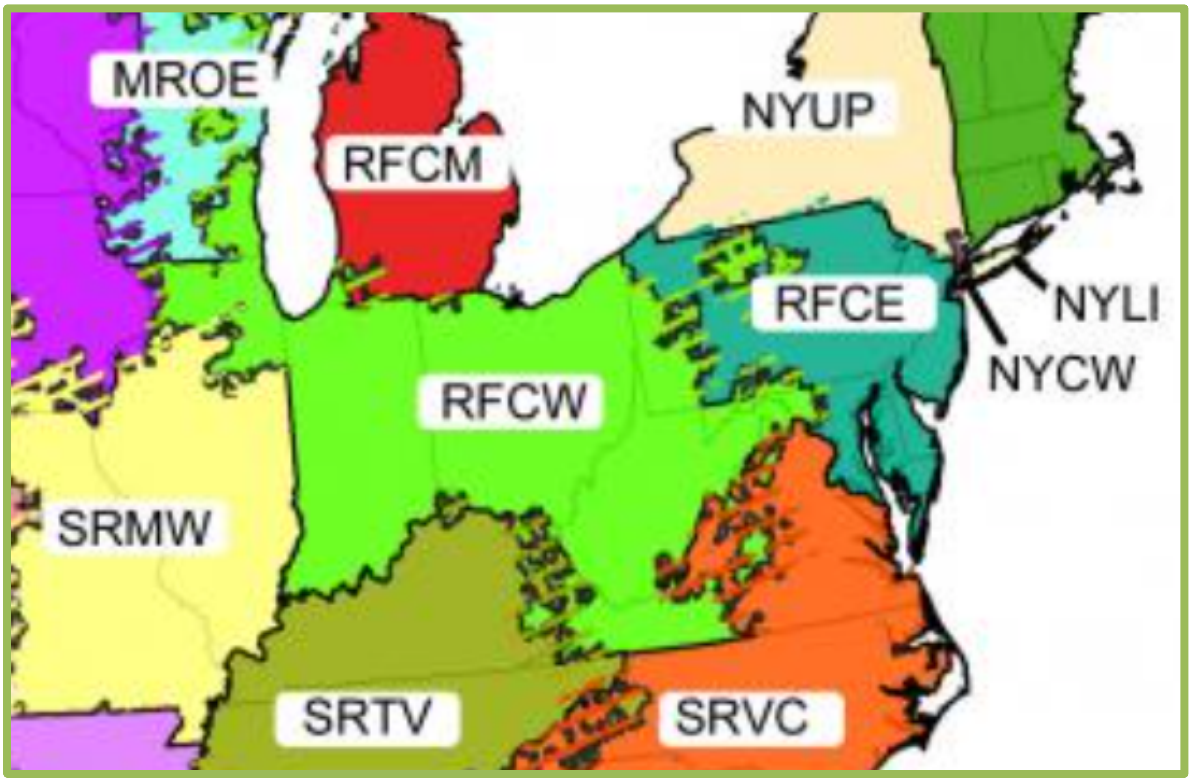


Image USEPA

[104] The U.S. EPA's "Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States." There are 26 eGRID subregions identified by the EPA[104], and these subregions are used in GHG reporting protocols to identify the carbon intensity of electricity produced in any given geographic area. D.C. is located in the Reliability First Corporation East subregion (RFCE). This subregion encompasses New Jersey, Delaware, the District, and substantial portions of Maryland and Pennsylvania as shown in the map below.

Generator vintage

The DC RPS states that Tier 1 generators, "Shall be eligible for inclusion in meeting the standard regardless of when the generating system or facility was placed in service."[105] Tier 2 generators are eligible only "at a system or facility that existed and was operational as of January 1, 2004."[106]

The other standards reviewed for generator vintage eligibility are:

- US EPA "Green Power"
- Green-e

Table A2-3 compares the vintage requirements under the DC RPS Tier 1 to the other two standards.

Table A2-3 – Generator Vintage Comparison

Vintage	DC RPS Tier 1	US EPA Green Power[107]	Green-e[108]
Projects in planning	X	X	X
Projects less than 15 years old	X	X	X
Projects of any age	X		

The vintage restrictions imposed by both US EPA and Green-e are not highly relevant to sourcing from wind and solar projects. As discussed in this study, wind and solar projects under development represent the largest source of potential long-term PPAs. The largest additional source of PPAs would be existing wind power projects, and many of these would remain available within the 15-year limit imposed by these alternate standards.

A more restrictive vintage limit is most important if certain hydropower resources are considered. Many hydro projects have been in service for decades, and the District should consider whether it wants to support their operation vis-à-vis newer resources.

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[105] Code of the District of Columbia Title 34 Public Utilities Chapter 14A. Renewable Energy Portfolio Standard, Section 34-1433(a)(1)
[106] Ibid Section 34-1433(b)
[107] EPA's Green Power Partnership Requirements, U.S. Environmental Protection Agency, September 2017 pp. 8-9 https://www.epa.gov/sites/production/files/2016-01/documents/gpp_partnership_reqs.pdf
[108] Green-e Renewable Energy Standard for Canada and the United States, Version 3.1, June 9, 2017 Center for Resource Solutions, p. 7 https://www.green-e.org/docs/energy/Green-e%20Standard%20v3.1%20US.pdf

APPENDIX 3

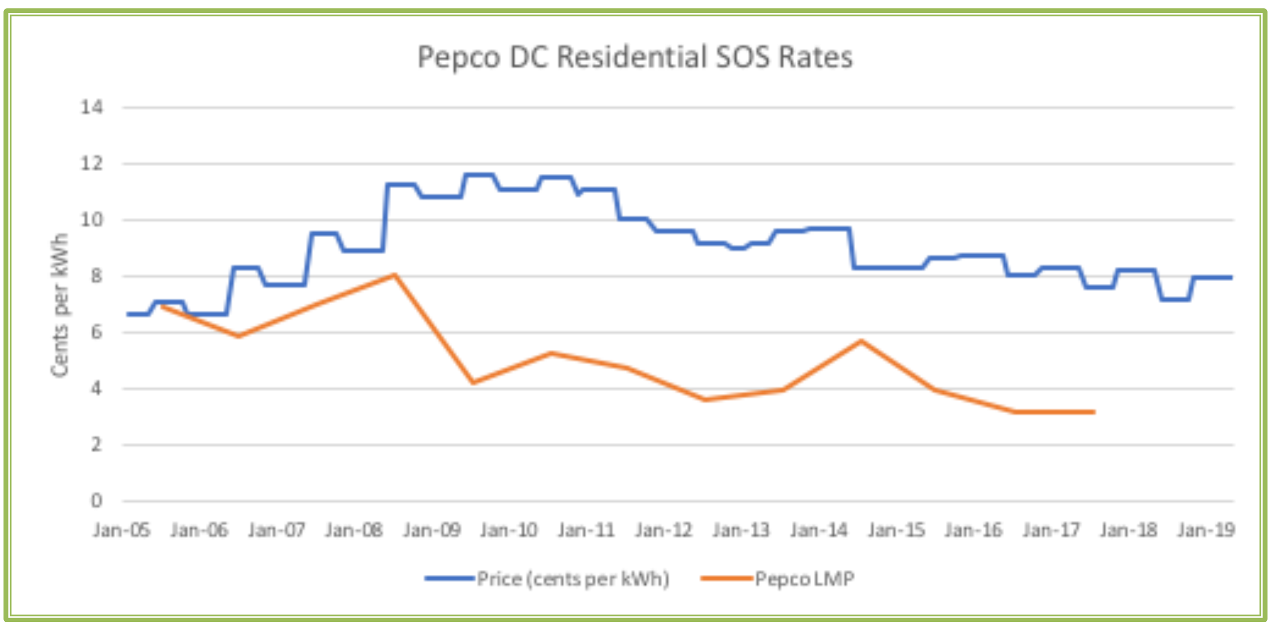
SOS MODEL

Residential SOS

Figure A3.1 below shows the history of the District's Residential SOS rates. These rates include costs of generation supplied by wholesale suppliers, transmission, administrative charges and a procurement cost adjustment. Residential SOS rates have moved up and down over the past 14 years in response to wholesale electricity market dynamics.

Figure A3.1 also compares Residential SOS rates to the average annual PJM LMP energy prices for the Pepco delivery zone[109]. As described in Section 4 of this study, energy is one of several components making up total SOS electricity costs, but it is the largest. Figure A3.1 shows that Residential SOS rates are less variable from year to year than wholesale market energy rates and tend to lag wholesale market trends. The lagging is especially noticeable beginning in 2009 when wholesale energy prices declined sharply. Both the "smoothing" and lagging result from the layered, multi-year SOS contracting structure.

Figure A3.1[110] - DC Residential SOS Prices vs. PJM Energy Prices



[109] The PJM figures are simple averages of PJM real-time LMPs for the Pepco DC delivery zone. The average is not weighted to the hourly electricity load profile of end-user load.
[110] Data on Pepco Residential SOS rates from DCPSC website "History of Electric Generation & Transmission Prices, by Company (Feb 2005 to date)" graphed by CRI. Pepco LMP data are from PJM Data Miner, tabulated by CRI.

Small Commercial and Large Commercial SOS[111]

Small Commercial SOS is structured similarly to Residential SOS (i.e. summer/winter pricing with the same price elements included) but tends to be slightly lower – about ½ cent per kWh at present.

Large Commercial SOS rates are designed to follow wholesale market prices more closely than Residential and Small Commercial SOS. The procurements include only one-year wholesale supply contracts, thereby eliminating the smoothing and lagging features of a layered, multi-year structure.

Modeling and projections

Residential electricity supply pricing model

To illustrate the potential impact of incorporating PPAs into an SOS purchasing strategy, a retail electricity supply pricing model was created by CRI for this study. Modeling is limited to Residential SOS rates due to the availability of complete historical pricing data on that class of service.

The model includes all SOS cost elements: generation costs (energy, installed capacity, and ancillary services), ARR/FTR credits, transmission charges, RPS compliance costs, supplier margins and risk management, and Pepco administrative charges.

In Section 3 of this study, the model is used to produce a forecast of Residential SOS prices through 2033 based on a continuation of the current SOS purchasing strategy. CRI feels it is valuable to project total SOS prices in this way to illustrate the effects of a PPA strategy on actual customer bills. It is important to clarify, for example, that PPAs only affect certain SOS cost components, so SOS prices in total will still be expected to increase over time even if PPAs are incorporated.

As also presented in Section 3 of this report, however, a simpler analytical approach that looks only at energy supply and the Tier 1 compliance REC cost components allows the effects of PPAs to be seen more clearly.

The retail electricity supply pricing model also supports an understanding of the PPA supply strategy discussed in Section 4 of this report. Many of the cost elements that comprise SOS do not change whether an FRS or PPA purchasing strategy is employed, rather, the management of the individual components shifts from the wholesale FRS provider to the SOS Administrator.

The forecasting assumptions for each element of the model are set forth in Table A3.1. The model is constructed to produces annual estimates of SOS costs based on pricing inputs for each particular year. The current SOS procurement process, as discussed above, creates a lagging and

[111] The DCPSC does not post the history of small commercial or large commercial SOS rates, as it does for residential rates. So, the graphs and trending of residential SOS provided in this Appendix cannot be duplicated for commercial rates.

smoothing of SOS prices. The model produces this effect by using a 4-year trailing average of SOS *costs* to produce each year's SOS *price*. While the 4-year lag is slightly longer than the actual duration of SOS contracts at the present time, as shown in Figure A3.4 below, it correlates well to the historical relationship of annual SOS costs to SOS prices.

Table A3-1 – SOS Model Cost Elements and Assumptions

Cost Element	Forecasting Assumption	2019 Value ($/MWH)	2033 Value ($/MWH)
Energy			
PJM Average	1.9% per year escalation EIA (1)	$ 30.67	$ 40.47
Pepco Zone Premium	$4.00 per MWH 2015 – 2017 average	$ 4.00	$ 4.00
Load Profile Premium	$3.00 per MWH CRI analysis using DOE residential load profile (2) 2015 – 2017 average	$ 3.00	$ 3.00
Energy Loss Factor	1.0572 Current Pepco low voltage factor	1.0572	1.0572
Capacity			
Ratio of Capacity to Annual Energy Use	4.32 kW capacity per 12,507 kWh annual usage CRI analysis of DOE residential load profile (2)	4.32/12,507	4.32/12,507
PJM RPM SWMAAC	Actual RPM auction results through the 2021/2022 planning year; $122/MW/day used thereafter as average RPM auction results 2017/2018 through 2021/2022 (3)	$ 100.00	$ 122.00
Capacity Loss Factor	1.0963 Current Pepco factor	1.0963	1.0963
Ancillary Services	$3.00 per MWH CRI estimate	$ 3.00	$ 3.00
ARR/FTR Credits	($2.00) per MWH CRI estimate	($ 2.00)	($ 2.00)
Transmission	6.7% per year escalation average 2008 – 2017 escalation rate of Pepco SOS transmission rates (4)	$ 8.43	$ 20.90
RPS Compliance			
Tier 1 Target	Per current DC RPS	17.5%	50.0%

Cost Element	Forecasting Assumption	2019 Value ($/MWH)	2033 Value ($/MWH)
Tier 1 REC Price	$2.30 per MWH 2015 – 2017 average for compliance wind RECs per DCPSC (5)	$ 2.30	$ 2.30
Solar Target	Per current DC RPS	1.35%	5.00%
Solar SREC Price	$100 below ACP through 2031, $40/MWH thereafter CRI estimate of approximate current market differential	$400/MWH	$40/MWH
SOS Wholesale Supplier Risk Management and Margin	$3.00 per MWH CRI estimate	$ 3.00	$ 3.00
Pepco Administrative Charge	$3.00 / MWH Current Pepco SOS tariff	$ 3.00	$ 3.00

Future electricity prices are subject to significant uncertainty and year-to-year variability that is not reflected in forecasts. The modeling can serve successfully, however, to allow comparison of alternative SOS procurement approaches based on consistent assumptions.

Table A3.1 citations:

(1) Escalation rate derived from EIA Annual Energy Outlook 2018 - Interactive Table Viewer – Nominal Electricity Generation Prices 2019 (6.5 cents per kWh) to 2033 (8.5 cents per kWh)
(2) US DOE https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-state
(3) 2021/2022 RPM Base Residual Auction Results, PJM Interconnection, Figure 2
(4) Tabulated historical figures from Pepco District of Columbia Tariff Archive https://www.pepco.com/MyAccount/MyBillUsage/Pages/DC/TariffArchiveDC.aspx
0.413 cents per kWh in 2008; 0.790 cents per kWh 2018
Note that EIA's projection of national average increases in transmission costs is significantly lower than the Pepco trailing 10-year average. Data in the EIA Annual Energy Outlook 2018 – Interactive Table Viewer – Nominal Electricity Transmission Prices 2019 (1.5 cents per kWh) to 2033 (2.3 cents per kWh) yields a 3.1% escalator
(5) Report on the Renewable Energy Portfolio Standard for Compliance Year 2017, DCPSC, May 1, 2018, table on p. 18. Per the table on page 17, wind RECs accounted for approximately 2/3 of all Tier 1 compliance RECs in 2017.

Figure A3.2 shows the detailed modeling results for 2018 through 2033. Figure A.3.3 shows historical data (including some estimates where historical data is not available) compiled in the model's structure. Figure A.3.4 shows the annual modeled SOS costs based on the historical data compared to actual SOS costs and compared to a 4-year rolling average that correlates the two fairly closely.

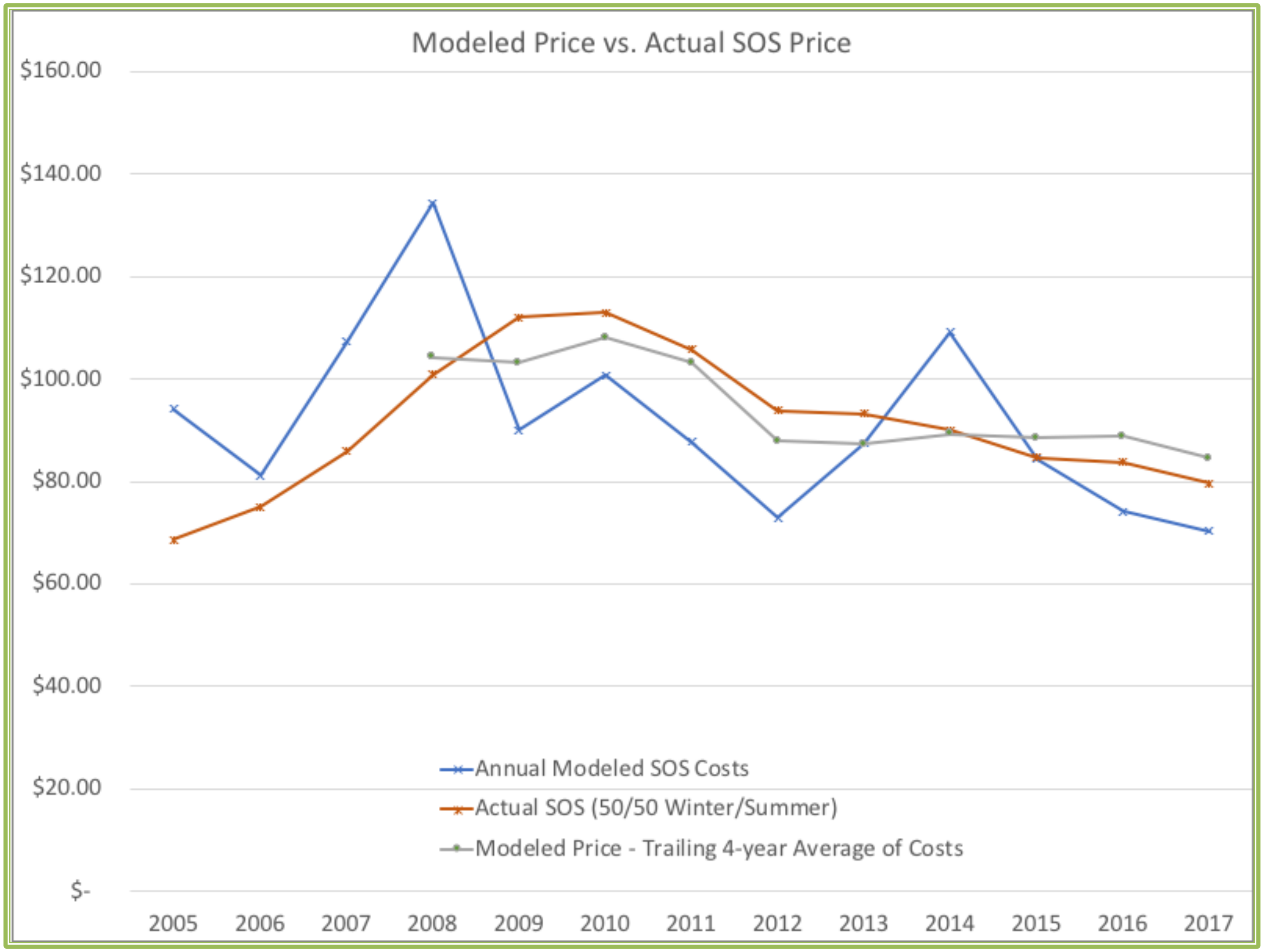
Figure A3.2 – Modeled SOS Cost Projections

All figures in $/MWH unless otherwise noted	**Projections**	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation																	
Energy ("LMP")																	
RTO Average Pricing	**1.91%**	$ 30.04	$ 30.62	$ 31.20	$ 31.80	$ 32.40	$ 33.02	$ 33.65	$ 34.30	$ 34.95	$ 35.62	$ 36.30	$ 36.99	$ 37.70	$ 38.42	$ 39.15	$ 39.90
Premium to Pepco Zone	**$ 4.00**	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00
Pepco Zone Average		$ 34.04	$ 34.62	$ 35.20	$ 35.80	$ 36.40	$ 37.02	$ 37.65	$ 38.30	$ 38.95	$ 39.62	$ 40.30	$ 40.99	$ 41.70	$ 42.42	$ 43.15	$ 43.90
Premium for Load Profile	**$ 3.00**	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
Total "Shaped" Price		$ 37.04	$ 37.62	$ 38.20	$ 38.80	$ 39.40	$ 40.02	$ 40.65	$ 41.30	$ 41.95	$ 42.62	$ 43.30	$ 43.99	$ 44.70	$ 45.42	$ 46.15	$ 46.90
Energy Loss Factor	**1.0572**	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572	1.0572
Total Energy Price w/ Losses		$ 39.16	$ 39.77	$ 40.39	$ 41.02	$ 41.66	$ 42.31	$ 42.98	$ 43.66	$ 44.35	$ 45.06	$ 45.78	$ 46.51	$ 47.26	$ 48.02	$ 48.79	$ 49.58
ARR/FTR Credits	**$ (2.00)**	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)
Capacity																	
Load Profile Peak Load (kW)	**4.32**	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32
Load Profile Annual Use (kWh)	**12,507**	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507
Planning Year		2018/2019	2019/2020	2020/2021	2021/2022												
Capacity Price SWMAAC ($/MW/day)		$ 164.77	$ 100.00	$ 86.04	$ 140.00	**$ 122.00**	$ 122.00	$ 122.00	$ 122.00	$ 122.00	$ 122.00	$ 122.00	$ 122.00	$ 122.00	$ 122.00	$ 122.00	$ 122.00
Capacity Loss Factor	**1.0963**	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963	1.0963
Capacity Price w / Losses		$ 20.20	$ 17.55	$ 12.70	$ 16.24	$ 17.90	$ 16.86	$ 16.86	$ 16.86	$ 16.86	$ 16.86	$ 16.86	$ 16.86	$ 16.86	$ 16.86	$ 16.86	$ 16.86
Ancillary Services	**$ 3.00**	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
Transmission																	
Pepco Transmission Rate	**6.70%**	$ 7.90	$ 8.43	$ 8.99	$ 9.60	$ 10.24	$ 10.93	$ 11.66	$ 12.44	$ 13.27	$ 14.16	$ 15.11	$ 16.12	$ 17.20	$ 18.36	$ 19.59	$ 20.90
EIA AOE 2018 national forecast escalator	**3.10%**																
RPS Compliance																	
Tier 2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tier 1		$ 0.36	$ 0.40	$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 0.53	$ 0.60	$ 0.67	$ 0.74	$ 0.81	$ 0.87	$ 0.97	$ 1.06	$ 1.15	$ 1.15
Solar		$ 4.60	$ 5.40	$ 6.32	$ 7.40	$ 8.70	$ 10.00	$ 7.80	$ 8.55	$ 9.45	$ 10.35	$ 11.25	$ 8.20	$ 9.00	$ 9.50	$ 2.00	$ 2.00
Total		$ 4.96	$ 5.80	$ 6.78	$ 7.86	$ 9.16	$ 10.46	$ 8.33	$ 9.15	$ 10.12	$ 11.09	$ 12.06	$ 9.07	$ 9.97	$ 10.56	$ 3.15	$ 3.15
Supplier Risk Management & Margin (FRS)	**$ 3.00**	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
Pepco Residential Administrative Charge	**$ 3.00**	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
Annual Modeled SOS Costs		**$ 79.21**	**$ 78.55**	**$ 75.86**	**$ 81.72**	**$ 85.96**	**$ 87.56**	**$ 86.83**	**$ 89.11**	**$ 91.60**	**$ 94.17**	**$ 96.80**	**$ 95.57**	**$ 98.29**	**$ 100.79**	**$ 95.39**	**$ 97.49**
Modeled Price - Trailing 4-year Average of Costs		**$ 77.00**	**$ 75.54**	**$ 75.99**	**$ 78.83**	**$ 80.52**	**$ 82.77**	**$ 85.52**	**$ 87.36**	**$ 88.78**	**$ 90.43**	**$ 92.92**	**$ 94.54**	**$ 96.21**	**$ 97.86**	**$ 97.51**	**$ 97.99**
Historic Residential SOS Prices ($/MWH)																	
Summer (cents per kWh)		7.20															
Winter (cents per kWh)		8.26															
Actual SOS (50/50 Winter/Summer)		**$ 77.26**															
Change from prior year		**$ (2.30)**															

Figure A3.3 – Backcast SOS Model

All figures in $/MWH unless otherwise noted	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Projections
Generation														
Energy ("LMP")														
RTO Average Pricing	$ 57.89	$ 48.10	$ 54.67	$ 66.12	$ 37.00	$ 44.57	$ 42.52	$ 32.79	$ 37.15	$ 49.15	$ 34.12	$ 28.10	$ 29.48	**1.91%**
Premium to Pepco Zone	$ 11.21	$ 10.75	$ 15.66	$ 14.27	$ 4.88	$ 8.28	$ 4.82	$ 3.55	$ 2.75	$ 8.19	$ 5.09	$ 4.09	$ 2.22	**$ 4.00**
Pepco Zone Average	$ 69.10	$ 58.85	$ 70.33	$ 80.39	$ 41.88	$ 52.85	$ 47.34	$ 36.34	$ 39.90	$ 57.34	$ 39.21	$ 32.19	$ 31.70	
Premium for Load Profile	$ 8.21	$ 6.96	$ 6.23	$ 9.05	$ 3.49	$ 5.64	$ 4.90	$ 3.55	$ 3.56	$ 6.84	$ 4.06	$ 2.48	$ 2.30	**$ 3.00**
Total "Shaped" Price	$ 77.32	$ 65.81	$ 76.56	$ 89.44	$ 45.37	$ 58.50	$ 52.23	$ 39.90	$ 43.46	$ 64.18	$ 43.27	$ 34.67	$ 34.01	
Energy Loss Factor	1.0680	1.0680	1.0680	1.0680	1.0680	1.0680	1.0680	1.0680	1.0680	1.0680	1.0572	1.0572	1.0572	**1.0572**
Total Energy Price w/ Losses	$ 82.57	$ 70.29	$ 81.76	$ 95.52	$ 48.46	$ 62.47	$ 55.79	$ 42.61	$ 46.42	$ 68.54	$ 45.75	$ 36.66	$ 35.95	
ARR/FTR Credits	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	$ (2.00)	**$ (2.00)**
Capacity														
Load Profile Peak Load (kW)	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	**4.32**
Load Profile Annual Use (kWh)	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	12,507	**12,507**
Planning Year			2007/2008	2008/2009	2009/201	2010/201	2011/201	2012/201	2013/201	2014/201	2015/201	2016/201	2017/2018	
Capacity Price SWMAAC ($/MW/day)	$ 6.12	$ 5.73	$ 188.54	$ 210.11	$ 237.33	$ 174.29	$ 110.00	$ 133.37	$ 226.15	$ 136.50	$ 167.46	$ 119.13	$ 120.00	
Capacity Loss Factor	1.0930	1.0930	1.0930	1.0930	1.0930	1.0930	1.0930	1.0930	1.0930	1.0930	1.0963	1.0963	1.0963	**1.0963**
Capacity Price w / Losses	$ 1.51	$ 0.81	$ 15.48	$ 27.71	$ 31.14	$ 27.64	$ 18.85	$ 17.04	$ 25.84	$ 23.96	$ 21.36	$ 19.25	$ 16.54	
Ancillary Services	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	**$ 3.00**
Transmission														
Pepco Transmission Rate	**$ 3.00**	**$ 3.00**	**$ 3.00**	$ 4.13	$ 3.32	$ 3.44	$ 4.79	$ 4.54	$ 6.20	$ 6.85	$ 7.04	$ 7.04	$ 6.65	**6.70%**
EIA AOE 2018 national forecast escalator														**3.10%**
RPS Compliance														
Tier 2			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Tier 1			$ -	$ -	$ 0.01	$ -	$ 0.10	$ 0.12	$ 0.16	$ 0.20	$ 0.19	$ 0.20	$ 0.36	
Solar			$ -	$ -	$ 0.08	$ 0.10	$ 1.20	$ 1.64	$ 1.82	$ 2.50	$ 3.05	$ 3.94	$ 3.82	
Total	$ -	$ -	$ -	$ -	$ 0.09	$ 0.10	$ 1.30	$ 1.76	$ 1.98	$ 2.70	$ 3.24	$ 4.14	$ 4.19	
Supplier Risk Management & Margin (FRS)	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	**$ 3.00**
Pepco Residential Administrative Charge	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	**$ 3.00**
Annual Modeled SOS Costs	**$ 94.08**	**$ 81.10**	**$ 107.25**	**$ 134.36**	**$ 90.01**	**$ 100.65**	**$ 87.73**	**$ 72.95**	**$ 87.43**	**$ 109.05**	**$ 84.39**	**$ 74.08**	**$ 70.33**	
Modeled Price - Trailing 4-year Average of Costs				**$ 104.20**	**$ 103.18**	**$ 108.07**	**$ 103.19**	**$ 87.83**	**$ 87.19**	**$ 89.29**	**$ 88.45**	**$ 88.74**	**$ 84.46**	
Historic Residential SOS Prices ($/MWH)														
Summer (cents per kWh)	7.05	8.34	9.48	11.23	11.57	11.49	10.05	9.14	9.61	8.29	8.64	8.05	7.62	
Winter (cents per kWh)	6.66	6.66	7.71	8.93	10.82	11.11	11.10	9.63	9.03	9.70	8.29	8.70	8.29	
Actual SOS (50/50 Winter/Summer)	**$ 68.55**	**$ 75.00**	**$ 85.95**	**$ 100.80**	**$ 111.95**	**$ 113.00**	**$ 105.75**	**$ 93.85**	**$ 93.20**	**$ 89.95**	**$ 84.65**	**$ 83.75**	**$ 79.55**	
Change from prior year		**$ 6.45**	**$ 10.95**	**$ 14.85**	**$ 11.15**	**$ 1.05**	**$ (7.25)**	**$ (11.90)**	**$ (0.65)**	**$ (3.25)**	**$ (5.30)**	**$ (0.90)**	**$ (4.20)**	

Figure A3.4 – Backcast SOS Model vs. Actual SOS Prices



APPENDIX 4

PPA PURCHASING SCENARIO DETAIL

Ramp rates, sourcing and annual PPA procurement volumes

As discussed in the Section 3, PPA purchasing scenarios were developed to supply the combined Residential and Commercial SOS requirements. Scenarios included three different ramp rates, a baseline sourcing assumption and two alternate sourcing options:

- Ramp Rate #1 – Reach 70% of SOS requirements in 3 years
- Ramp Rate #2 – Reach 90% of SOS requirements in 6 years
- Ramp Rate #3 – Reach 90% of SOS requirements in 12 years
- Sourcing Baseline
    - Each PPA is for the full output of a project
    - All PPAs are with new wind and solar projects
    - All projects are sourced from PJM states
- Sourcing Alternates
    - Alternate #1 – PPA's for shares of portfolios of new renewable energy projects
    - Alternate #2 – Purchases from projects located either inside or outside PJM states

Each ramp rate implies an annual PPA procurement volume needed to meet the ultimate percentage goal in the established time frame. Using the current, approximate combined annual residential and commercial SOS requirements of 2,800,000 MWH/year, the following target annual PPA procurements were chosen to correspond to the three ramp rates:

Ramp Rate #1 – 650,000 MWH
Ramp Rate #2 – 420,000 MWH
Ramp Rate #3 – 210,000 MWH

PPA project roster and selection

A roster of candidate projects to fill the annual procurement requirements was developed by querying the LevelTen Energy Marketplace.[112] The Marketplace is an on-line tool made available by LevelTen Energy free of charge to registered renewable energy buyers. It includes pricing offers, project technical information and economic valuation parameters on hundreds of wind and solar projects under development across the U.S. including approximately 100 in the PJM states.

For the national sourcing alternate, any project in the Marketplace was considered, including projects in PJM, CAISO, ERCOT, MISO, NYISO and ISONE.

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[112] These queries were made throughout the month of July 2018. Note that the Marketplace is constantly being updated with information on available projects, pricing offers, and projected energy market data.

For each ramp rate, projects with annual output less than or equal to the targeted annual procurement were considered, but allowing an approximate 20% excess over target to slightly expand the roster of eligible projects.

From each query, the most economically attractive wind and solar projects were selected as a "short list" from which the scenarios were built.

Table A4-1 shows the project roster, and the specific projects selected for each ramp rate scenario and for the Alternate #1 portfolio.

Table A4-1 – Selected Regional Projects for All Ramp Rate Scenarios

Project ID	Size (MW)	Annual Production (MWH)	State	Projected In-Service Date	Ramp Rate 3 yrs.	Ramp Rate 6 yrs.	Ramp Rate 12 yrs.	Port.
Wind Power Projects								
1199	150	468,000	IL	Q4 2020	X	X		X
1021	200	200,000	OH	Q2 2020		X	X	X
129	100	445,672	WV	Q2 2020	X	X		
964	60	200,000	IN	Q4 2019			X	
125	50	191,000	PA	Q4 2019			X	
1011	50	170,000	IL	Q4 2018			X	
1097	65	221,000	IL	Q4 2019			X	
1005	60	211,000	IL	Q4 2018			X	
	Solar Power Projects							
1402	75	169,000	NC	Q4 2021	X	X	X	X
1059	50	107,000	VA	Q4 2020	X	X	X	X
1398	75	165,000	VA	Q3 2021	X	X	X	X
216	80	182,000	VA	Q2 2020	X	X	X	X
113	100	226,000	VA	Q1 2020	X	X	X	
1092	70	146,000	VA	Q4 2020	X	X	X	
774	75	176,000	VA	Q2 2020		X	X	
39	65	155,000	VA	Q2 2021		X	X	

Table A4-2 shows the project roster used for the Alternate #2 national sourcing scenario. Note that the roster of wind projects is completely different from the baseline sourcing, since more economically attractive wind projects are located in Texas and Oklahoma. While Texas also hosts economically attractive solar projects, Virginia and North Carolina projects compare favorably to any projects in the nation.

Table A4-2 – Selected National Projects for 3-year Ramp Rate Scenario

Project ID	Size (MW)	Annual Production (MWH)	State	Projected In-Service Date	National Ramp Rate 3 Yrs.
Wind Power Projects					
1417	150	608,000	OK	Q4 2020	X
993	150	590,000	TX	Q4 2019	X
Solar Power Projects					
1063	150	430,000	TX	Q1 2020	X
1402	75	169,000	NC	Q4 2021	X
1398	75	165,000	VA	Q3 2021	X
27	200	419,000	TX	Q4 2020	X
1059	50	107,000	VA	Q4 2020	X

Projects were selected for an approximate 50/50 balance between wind and solar production when the all PPA purchases are complete. To achieve a level of ongoing balance, wind and solar purchases were alternated by year as needed.

PPA pricing and power value

Each project in the Marketplace has an offered PPA price based on the following standard parameters:

- 15-year term
- Flat price for full term – no escalator
- Energy plus RECs (capacity credits retained by project owner)

Each project also has a power delivery point specified as a "hub" within the relevant RTO. LevelTen projects the forward value of power by year for each project based on its proprietary analysis. That analysis is based on forward market quotes for blocks of power, adjusted for the production profiles of each wind or solar project, subjected to other advanced analytics.

Figures A4-1 through A4-5 show the data supporting the graphs in Figures 3.1 through 3.4 in Section 3 of this report.

Figure A4-1 – 3-Year Ramp Rate to 70%

	Annual Production Yr.1 - (MWH)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Scenario #1ARC - 3 year ramp to 70% renewables, DCRPS Marketplace projects, OTCGH forward curve																
New procurment process determined																
First RFP / Project(s) Operational																
Second RFP / Project(s) Operational																
Third RFP / Project(s) Operational																
Cumulative % of Supply Under PPAs					23%	46%	70%									
Residential + Commercial SOS																
Annual Residential SOS Volume (MWH)	**2,800,000**															
Annual PPA Procurement Target Volume (MWH/yr.)			650,000	650,000	650,000											
Flowing PPA Supply (MWH)					650,000	1,300,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000
Wind																
Project 1199, IL, MISO, Q4 2020, 150 MW, 468,000 MWH/yr.	**468,000**				$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00
MISO Indiana Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 29.48	$ 29.32	$ 29.43	$ 29.71	$ 30.24	$ 30.86	$ 31.35	$ 31.80	$ 32.43	$ 33.11	$ 33.78	$ 34.43
Annual Net Value/(Cost)					$ 2.48	$ 2.32	$ 2.43	$ 2.71	$ 3.24	$ 3.86	$ 4.35	$ 4.80	$ 5.43	$ 6.11	$ 6.78	$ 7.43
Project 129, WV, PJM, Q2 2020, 120 MW, 482,000 MWH/yr.	**482,000**				$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00
PJM Dominion Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 33.58	$ 33.55	$ 34.06	$ 34.91	$ 35.84	$ 36.81	$ 37.07	$ 37.81	$ 38.61	$ 39.37	$ 40.16	$ 40.92
Annual Net Value/(Cost)					$ (0.42)	$ (0.45)	$ 0.06	$ 0.91	$ 1.84	$ 2.81	$ 3.07	$ 3.81	$ 4.61	$ 5.37	$ 6.16	$ 6.92
Solar																
Project 1402, NC, PJM, Q4 2021, 75 MW, 169,000 MWH/yr.	**169,000**				$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.18	$ 39.65	$ 40.52	$ 41.54	$ 42.61	$ 43.32	$ 43.94	$ 44.79	$ 45.75	$ 46.78	$ 47.61	$ 48.52
Annual Net Value/(Cost)					$ 10.68	$ 11.15	$ 12.02	$ 13.04	$ 14.11	$ 14.82	$ 15.44	$ 16.29	$ 17.25	$ 18.28	$ 19.11	$ 20.02
Project 1398, VA, PJM, Q3 2021, 75 MW, 165,000 MWH/yr.	**165,000**				$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.22	$ 39.53	$ 40.29	$ 41.31	$ 42.39	$ 43.34	$ 43.76	$ 44.63	$ 45.56	$ 46.55	$ 47.45	$ 48.32
Annual Net Value/(Cost)					$ 10.22	$ 10.53	$ 11.29	$ 12.31	$ 13.39	$ 14.34	$ 14.76	$ 15.63	$ 16.56	$ 17.55	$ 18.45	$ 19.32
Project 1059, VA, PJM, Q4 2020, 50 MW, 107,000 MWH/yr.	**107,000**				$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50
PJM West Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 35.35	$ 35.68	$ 36.51	$ 37.43	$ 38.40	$ 39.22	$ 39.80	$ 40.57	$ 41.45	$ 42.33	$ 43.09	$ 43.94
Annual Net Value/(Cost)					$ 9.85	$ 10.18	$ 11.01	$ 11.93	$ 12.90	$ 13.72	$ 14.30	$ 15.07	$ 15.95	$ 16.83	$ 17.59	$ 18.44
Project 216, VA, PJM, Q2 2020, 80 MW, 182,000 MWH/yr.	**182,000**				$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80
PJM Dominion Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.29	$ 39.49	$ 40.18	$ 41.23	$ 42.29	$ 43.38	$ 43.68	$ 44.58	$ 45.53	$ 46.44	$ 47.39	$ 48.27
Annual Net Value/(Cost)					$ 7.49	$ 7.69	$ 8.38	$ 9.43	$ 10.49	$ 11.58	$ 11.88	$ 12.78	$ 13.73	$ 14.64	$ 15.59	$ 16.47
Project 113, NC, PJM, Q1 2020, 100 MW, 226,000 MWH/yr.	**226,000**				$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 40.18	$ 40.29	$ 40.80	$ 41.83	$ 42.88	$ 44.00	$ 44.55	$ 45.28	$ 46.24	$ 47.20	$ 48.18	$ 49.11
Annual Net Value/(Cost)					$ 7.18	$ 7.29	$ 7.80	$ 8.83	$ 9.88	$ 11.00	$ 11.55	$ 12.28	$ 13.24	$ 14.20	$ 15.18	$ 16.11
Project 1092, VA, PJM, Q4 2020, 70 MW, 146,000 MWH/yr.	**146,000**				$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.34	$ 39.82	$ 40.69	$ 41.71	$ 42.79	$ 43.51	$ 44.13	$ 44.98	$ 45.98	$ 46.98	$ 47.81	$ 48.73
Annual Net Value/(Cost)					$ 6.24	$ 6.72	$ 7.59	$ 8.61	$ 9.69	$ 10.41	$ 11.03	$ 11.88	$ 12.88	$ 13.88	$ 14.71	$ 15.63
Wind Total Volume	**950,000**	49%														
Solar Total Volume	**995,000**	51%														
Contracted Projects			Project 1092(S) Project 1402(S) Project 1398(S) Project 1059(S)	Project 1199(W) Project 216(S)	Project 129(W) Project 113(S)											
Contracted Volume			587,000	650,000	708,000											
Flowing Volume					587,000	1,237,000	1,945,000	1,945,000	1,945,000	1,945,000	1,945,000	1,945,000	1,945,000	1,945,000	1,945,000	1,945,000
Financial Benefit																
First Year Projects ($/MWH of SOS)					**$ 1.95**	**$ 2.03**	**$ 2.21**	**$ 2.42**	**$ 2.64**	**$ 2.81**	**$ 2.92**	**$ 3.10**	**$ 3.30**	**$ 3.50**	**$ 3.68**	**$ 3.87**
Second Year Projects ($/MWH of SOS)						**$ 0.89**	**$ 0.95**	**$ 1.07**	**$ 1.22**	**$ 1.40**	**$ 1.50**	**$ 1.63**	**$ 1.80**	**$ 1.97**	**$ 2.15**	**$ 2.31**
Third Year Projects ($/MWH os SOS)							**$ 0.64**	**$ 0.87**	**$ 1.11**	**$ 1.37**	**$ 1.46**	**$ 1.65**	**$ 1.86**	**$ 2.07**	**$ 2.29**	**$ 2.49**
Total Financial Benefit					**$ 1.95**	**$ 2.92**	**$ 3.80**	**$ 4.35**	**$ 4.98**	**$ 5.58**	**$ 5.88**	**$ 6.38**	**$ 6.96**	**$ 7.55**	**$ 8.11**	**$ 8.67**

Figure A4-2 – 6-year Ramp Rate to 90%

	Annual Production Yr.1 - (MWH)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Scenario #2ARC - 6 year ramp to 90% renewables, DCRPS Marketplace projects, OTCGH forward curve																
New procurment process determined																
First RFP / Project(s) Operational																
Second RFP / Project(s) Operational																
Third RFP / Project(s) Operational																
Fourth RFP / Project(s) Operational																
Fifth RFP / Project(s) Operational																
Sixth RFP / Project(s) Operational																
Cumulative % of Supply Under PPAs					15%	30%	45%	60%	75%	90%						
Residential + Commercial SOS																
Annual Residential + Commercial SOS Volume (MWH)	**2,800,000**															
Annual PPA Procurement Target Volume (MWH/yr.)			420,000	420,000	420,000	420,000	420,000	420,000								
Flowing PPA Supply (MWH)					420,000	840,000	1,260,000	1,680,000	2,100,000	2,520,000	2,520,000	2,520,000	2,520,000	2,520,000	2,520,000	2,520,000
Wind																
Project 1199, IL, MISO, Q4 2020, 150 MW, 468,000 MWH/yr.	**468,000**				$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00
MISO Indiana Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 29.48	$ 29.32	$ 29.43	$ 29.71	$ 30.24	$ 30.86	$ 31.35	$ 31.80	$ 32.43	$ 33.11	$ 33.78	$ 34.43
Annual Net Value/(Cost)					$ 2.48	$ 2.32	$ 2.43	$ 2.71	$ 3.24	$ 3.86	$ 4.35	$ 4.80	$ 5.43	$ 6.11	$ 6.78	$ 7.43
Project 1021, OH, PJM, Q2 2020, 200 MW, 200,000 MWH/yr.	**200,000**				$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00
PJM AEP Dayton Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 29.30	$ 29.85	$ 30.10	$ 29.76	$ 29.73	$ 29.48	$ 29.71	$ 30.31	$ 30.93	$ 31.55	$ 32.18	$ 32.80
Annual Net Value/(Cost)					$ 3.30	$ 3.85	$ 4.10	$ 3.76	$ 3.73	$ 3.48	$ 3.71	$ 4.31	$ 4.93	$ 5.55	$ 6.18	$ 6.80
Project 129, WV, PJM, Q2 2020, 120 MW, 482,000 MWH/yr.	**482,000**				$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00	$ 34.00
PJM Dominion Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 33.58	$ 33.55	$ 34.06	$ 34.91	$ 35.84	$ 36.81	$ 37.07	$ 37.81	$ 38.61	$ 39.37	$ 40.16	$ 40.92
Annual Net Value/(Cost)					$ (0.42)	$ (0.45)	$ 0.06	$ 0.91	$ 1.84	$ 2.81	$ 3.07	$ 3.81	$ 4.61	$ 5.37	$ 6.16	$ 6.92
Solar																
Project 1402, NC, PJM, Q4 2021, 75 MW, 169,000 MWH/yr.	**169,000**				$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.18	$ 39.65	$ 40.52	$ 41.54	$ 42.61	$ 43.32	$ 43.94	$ 44.79	$ 45.75	$ 46.78	$ 47.61	$ 48.52
Annual Net Value/(Cost)					$ 10.68	$ 11.15	$ 12.02	$ 13.04	$ 14.11	$ 14.82	$ 15.44	$ 16.29	$ 17.25	$ 18.28	$ 19.11	$ 20.02
Project 1398, VA, PJM, Q3 2021, 75 MW, 165,000 MWH/yr.	**165,000**				$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.22	$ 39.53	$ 40.29	$ 41.31	$ 42.39	$ 43.34	$ 43.76	$ 44.63	$ 45.56	$ 46.55	$ 47.45	$ 48.32
Annual Net Value/(Cost)					$ 10.22	$ 10.53	$ 11.29	$ 12.31	$ 13.39	$ 14.34	$ 14.76	$ 15.63	$ 16.56	$ 17.55	$ 18.45	$ 19.32
Project 1059, VA, PJM, Q4 2020, 50 MW, 107,000 MWH/yr.	**107,000**				$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50
PJM West Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 35.35	$ 35.68	$ 36.51	$ 37.43	$ 38.40	$ 39.22	$ 39.80	$ 40.57	$ 41.45	$ 42.33	$ 43.09	$ 43.94
Annual Net Value/(Cost)					$ 9.85	$ 10.18	$ 11.01	$ 11.93	$ 12.90	$ 13.72	$ 14.30	$ 15.07	$ 15.95	$ 16.83	$ 17.59	$ 18.44
Project 216, VA, PJM, Q2 2020, 80 MW, 182,000 MWH/yr.	**182,000**				$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80
PJM Dominion Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.29	$ 39.49	$ 40.18	$ 41.23	$ 42.29	$ 43.38	$ 43.68	$ 44.58	$ 45.53	$ 46.44	$ 47.39	$ 48.27
Annual Net Value/(Cost)					$ 7.49	$ 7.69	$ 8.38	$ 9.43	$ 10.49	$ 11.58	$ 11.88	$ 12.78	$ 13.73	$ 14.64	$ 15.59	$ 16.47
Project 113, NC, PJM, Q1 2020, 100 MW, 226,000 MWH/yr.	**226,000**				$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 40.18	$ 40.29	$ 40.80	$ 41.83	$ 42.88	$ 44.00	$ 44.55	$ 45.28	$ 46.24	$ 47.20	$ 48.18	$ 49.11
Annual Net Value/(Cost)					$ 7.18	$ 7.29	$ 7.80	$ 8.83	$ 9.88	$ 11.00	$ 11.55	$ 12.28	$ 13.24	$ 14.20	$ 15.18	$ 16.11
Project 1092, VA, PJM, Q4 2020, 70 MW, 146,000 MWH/yr.	**146,000**				$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.34	$ 39.82	$ 40.69	$ 41.71	$ 42.79	$ 43.51	$ 44.13	$ 44.98	$ 45.98	$ 46.98	$ 47.81	$ 48.73
Annual Net Value/(Cost)					$ 6.24	$ 6.72	$ 7.59	$ 8.61	$ 9.69	$ 10.41	$ 11.03	$ 11.88	$ 12.88	$ 13.88	$ 14.71	$ 15.63
Project 774, VA, PJM, Q2 2020, 75 MW, 176,000 MWH/yr.	**176,000**				$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.12	$ 39.32	$ 40.01	$ 41.05	$ 42.11	$ 43.20	$ 43.50	$ 44.39	$ 45.34	$ 46.24	$ 47.19	$ 48.06
Annual Net Value/(Cost)					$ 6.27	$ 6.47	$ 7.16	$ 8.20	$ 9.26	$ 10.35	$ 10.65	$ 11.54	$ 12.49	$ 13.39	$ 14.34	$ 15.21
Project 39, VA, PJM, Q2 2021, 65 MW, 149,000 MWH/yr.	**149,000**				$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.07	$ 39.25	$ 39.94	$ 40.97	$ 42.03	$ 43.13	$ 43.43	$ 44.29	$ 45.28	$ 46.18	$ 47.12	$ 47.98
Annual Net Value/(Cost)					$ 4.82	$ 5.00	$ 5.69	$ 6.72	$ 7.78	$ 8.88	$ 9.18	$ 10.04	$ 11.03	$ 11.93	$ 12.87	$ 13.73
Wind Total Volume	**1,150,000**	47%														
Solar Total Volume	**1,320,000**	53%														
Contracted Projects			Project 1402(S) Project 1398(S) Project 1059(S)	Project 1199(W)	Project 1021(S) Project 216(S)	Project 113(S) Project 1092(S)	Project 129(W)	Project 774(S) Project 39(S)								
Contracted Volume			441,000	468,000	382,000	372,000	482,000	325,000								
Flowing Volume					441,000	909,000	1,291,000	1,663,000	2,145,000	2,470,000	2,470,000	2,470,000	2,470,000	2,470,000	2,470,000	2,470,000
Financial Benefit																
First Year Projects ($/MWH of SOS)					**$ 1.62**	**$ 1.68**	**$ 1.81**	**$ 1.97**	**$ 2.13**	**$ 2.26**	**$ 2.35**	**$ 2.48**	**$ 2.63**	**$ 2.78**	**$ 2.91**	**$ 3.05**
Second Year Projects ($/MWH of SOS)						**$ 0.39**	**$ 0.41**	**$ 0.45**	**$ 0.54**	**$ 0.65**	**$ 0.73**	**$ 0.80**	**$ 0.91**	**$ 1.02**	**$ 1.13**	**$ 1.24**
Third Year Projects ($/MWH of SOS)							**$ 0.84**	**$ 0.88**	**$ 0.95**	**$ 1.00**	**$ 1.04**	**$ 1.14**	**$ 1.24**	**$ 1.35**	**$ 1.45**	**$ 1.56**
Fourth Year Projects ($/MWH of SOS)								**$ 1.16**	**$ 1.30**	**$ 1.43**	**$ 1.51**	**$ 1.61**	**$ 1.74**	**$ 1.87**	**$ 1.99**	**$ 2.12**
Fifth Year Projects ($/MWH of SOS)									**$ 0.32**	**$ 0.48**	**$ 0.53**	**$ 0.66**	**$ 0.79**	**$ 0.92**	**$ 1.06**	**$ 1.19**
Sixth Year Projects ($/MWH of SOS)										**$ 1.12**	**$ 1.16**	**$ 1.26**	**$ 1.37**	**$ 1.48**	**$ 1.59**	**$ 1.69**
Total Financial Benefit					**$ 1.62**	**$ 2.07**	**$ 3.06**	**$ 4.46**	**$ 5.24**	**$ 6.95**	**$ 7.31**	**$ 7.95**	**$ 8.68**	**$ 9.42**	**$ 10.14**	**$ 10.84**

Figure A4-3 – 12-Year Ramp Rate to 90% (Totals)

	Annual Production Yr.1 - (MWH)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Scenario #3ARC - 12 year ramp to 90% renewables, DCRPS Marketplace projects, OTCGH forward curve																
New procurment process determined																
First RFP / Project(s) Operational																
Second RFP / Project(s) Operational																
Third RFP / Project(s) Operational																
Fourth RFP / Project(s) Operational																
Fifth RFP / Project(s) Operational																
Sixth RFP / Project(s) Operational																
Seventh RFP / Project(s) Operational																
Eigth RFP / Project(s) Operational																
Ninth RFP / Project(s) Operational																
Tenth RFP / Project(s) Operational																
Eleventh RFP / Project(s) Operational																
Twelfth RFP / Project(s) Operational																
Cumulative % of Supply Under PPAs					8%	15%	23%	30%	38%	45%	53%	60%	68%	75%	83%	90%
Residential + Commercial SOS																
Annual Residential SOS Volume (MWH)	**2,800,000**															
Annual PPA Procurement Target Volume (MWH/yr.)			210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000		
Flowing PPA Supply (MWH)					210,000	420,000	630,000	840,000	1,050,000	1,260,000	1,470,000	1,680,000	1,890,000	2,100,000	2,310,000	2,520,000
Contracted Projects			Project 1402 (S)	Project 1021(W)	Project 1398(S)	Project 964(W)	Project 1059(S) Project 125(W)	Project 216(S)	Project 1011 (W)	Project 113(S)	Project 1097(W)	Project 1092(S) Project 774(S)	Project 1005(W) Project 39(S)			
Contracted Volume			169,000	200,000	165,000	200,000	298,000	182,000	170,000	226,000	221,000	322,000	360,000			
Flowing Volume					169,000	369,000	534,000	734,000	1,032,000	1,214,000	1,384,000	1,610,000	1,831,000	2,153,000	2,513,000	2,513,000
Financial Benefit																
First Year Projects ($/MWH of SOS)					**$ 0.64**	**$ 0.67**	**$ 0.73**	**$ 0.79**	**$ 0.85**	**$ 0.89**	**$ 0.93**	**$ 0.98**	**$ 1.04**	**$ 1.10**	**$ 1.15**	**$ 1.21**
Second Year Projects ($/MWH of SOS)						**$ 0.28**	**$ 0.29**	**$ 0.27**	**$ 0.27**	**$ 0.25**	**$ 0.27**	**$ 0.31**	**$ 0.35**	**$ 0.40**	**$ 0.44**	**$ 0.49**
Third Year Projects ($/MWH of SOS)							**$ 0.67**	**$ 0.73**	**$ 0.79**	**$ 0.85**	**$ 0.87**	**$ 0.92**	**$ 0.98**	**$ 1.03**	**$ 1.09**	**$ 1.14**
Fourth Year Projects ($/MWH of SOS)								**$ (0.31)**	**$ (0.27)**	**$ (0.23)**	**$ (0.21)**	**$ (0.17)**	**$ (0.13)**	**$ (0.09)**	**$ (0.06)**	**$ (0.02)**
Fifth Year Projects ($/MWH of SOS)									**$ 0.13**	**$ 0.23**	**$ 0.28**	**$ 0.36**	**$ 0.44**	**$ 0.53**	**$ 0.60**	**$ 0.68**
Sixth Year Projects ($/MWH of SOS)										**$ 0.75**	**$ 0.77**	**$ 0.83**	**$ 0.89**	**$ 0.95**	**$ 1.01**	**$ 1.07**
Seventh Year Projects ($/MWH of SOS)											**$ (0.33)**	**$ (0.30)**	**$ (0.27)**	**$ (0.23)**	**$ (0.21)**	**$ (0.17)**
Eighth Year Projects ($/MWH of SOS)												**$ 0.99**	**$ 1.07**	**$ 1.15**	**$ 1.23**	**$ 1.30**
Ninth Year Projects ($/MWH of SOS)													**$ (0.41)**	**$ (0.37)**	**$ (0.33)**	**$ (0.29)**
Tenth Year Projects ($/MWH of SOS)														**$ 1.57**	**$ 1.67**	**$ 1.77**
Eleventh Year Projects ($/MWH of SOS)															**$ 0.39**	**$ 0.47**
Total Financial Benefit					**$ 0.64**	**$ 0.95**	**$ 1.68**	**$ 1.47**	**$ 1.78**	**$ 2.73**	**$ 2.59**	**$ 3.92**	**$ 3.96**	**$ 6.03**	**$ 6.99**	**$ 7.65**

Figure A4-3 – 12-Year Ramp Rate to 90% (Detail)

Wind														
Project 1021, OH, PJM, Q2 2020, 200 MW, 200,000 MWH/yr.	200,000		$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00
PJM AEP Dayton Hub Value (LevelTen - OTCGH Forward Curve) (5)			$ 29.30	$ 29.85	$ 30.10	$ 29.76	$ 29.73	$ 29.48	$ 29.71	$ 30.31	$ 30.93	$ 31.55	$ 32.18	$ 32.80
Annual Net Value/(Cost)			$ 3.30	$ 3.85	$ 4.10	$ 3.76	$ 3.73	$ 3.48	$ 3.71	$ 4.31	$ 4.93	$ 5.55	$ 6.18	$ 6.80
Project 964, IN, PJM, Q4 2019, 60 MW, 200,000 MWH/yr.	200,000		$ 28.30	$ 28.30	$ 28.30	$ 28.30	$ 28.30	$ 28.30	$ 28.30	$ 28.30	$ 28.30	$ 28.30	$ 28.30	$ 28.30
PJM Northern Illinois Hub Value (LevelTen - OTCGH Forward Curve) (5)			$ 24.52	$ 24.92	$ 23.84	$ 23.96	$ 24.59	$ 25.04	$ 25.38	$ 25.89	$ 26.44	$ 26.99	$ 27.48	$ 28.02
Annual Net Value/(Cost)			$ (3.78)	$ (3.38)	$ (4.46)	$ (4.34)	$ (3.71)	$ (3.26)	$ (2.92)	$ (2.41)	$ (1.86)	$ (1.31)	$ (0.82)	$ (0.28)
Project 125, PA, PJM, Q4 2019, 50 MW, 191,000 MWH/yr.	191,000		$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50
PJM Western Hub Value (LevelTen - OTCGH Forward Curve) (5)			$ 30.57	$ 30.87	$ 31.58	$ 32.38	$ 33.23	$ 34.12	$ 34.60	$ 35.29	$ 36.03	$ 36.77	$ 37.46	$ 38.20
Annual Net Value/(Cost)			$ (7.93)	$ (7.63)	$ (6.92)	$ (6.12)	$ (5.27)	$ (4.38)	$ (3.90)	$ (3.21)	$ (2.47)	$ (1.73)	$ (1.04)	$ (0.30)
Project 1011, IL, PJM, Q4 2018, 50 MW, 170,000 MWH/yr.	170,000		$ 32.18	$ 32.18	$ 32.18	$ 32.18	$ 32.18	$ 32.18	$ 32.18	$ 32.18	$ 32.18	$ 32.18	$ 32.18	$ 32.18
PJM Northern Illinois Hub Value (LevelTen - OTCGH Forward Curve) (5)			$ 26.64	$ 27.00	$ 26.55	$ 25.27	$ 25.91	$ 26.45	$ 26.82	$ 27.18	$ 27.73	$ 28.45	$ 28.73	$ 29.30
Annual Net Value/(Cost)			$ (5.54)	$ (5.18)	$ (5.63)	$ (6.91)	$ (6.27)	$ (5.73)	$ (5.36)	$ (5.00)	$ (4.45)	$ (3.73)	$ (3.45)	$ (2.88)
Project 1097, IL, PJM, Q4 2019, 65 MW, 221,000 MWH/yr.	221,000		$ 30.10	$ 30.10	$ 30.10	$ 30.10	$ 30.10	$ 30.10	$ 30.10	$ 30.10	$ 30.10	$ 30.10	$ 30.10	$ 30.10
PJM Northern Illinois Hub Value (LevelTen - OTCGH Forward Curve) (5)			$ 23.30	$ 23.33	$ 24.06	$ 23.03	$ 23.12	$ 23.72	$ 24.14	$ 24.44	$ 24.92	$ 25.44	$ 25.97	$ 26.46
Annual Net Value/(Cost)			$ (6.80)	$ (6.77)	$ (6.04)	$ (7.07)	$ (6.98)	$ (6.38)	$ (5.96)	$ (5.66)	$ (5.18)	$ (4.66)	$ (4.13)	$ (3.64)
Project 1005, IL, PJM, Q4 2018, 60 MW, 211,000 MWH/yr.	211,000		$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90
PJM Northern Illinois Hub Value (LevelTen - OTCGH Forward Curve) (5)			$ 23.33	$ 23.36	$ 24.10	$ 23.05	$ 23.12	$ 23.73	$ 24.15	$ 24.45	$ 24.93	$ 25.46	$ 25.99	$ 26.47
Annual Net Value/(Cost)			$ (6.57)	$ (6.54)	$ (5.80)	$ (6.85)	$ (6.78)	$ (6.17)	$ (5.75)	$ (5.45)	$ (4.97)	$ (4.44)	$ (3.91)	$ (3.43)
Solar														
Project 1402, NC, PJM, Q4 2021, 75 MW, 169,000 MWH/yr.	169,000		$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)			$ 39.18	$ 39.65	$ 40.52	$ 41.54	$ 42.61	$ 43.32	$ 43.94	$ 44.79	$ 45.75	$ 46.78	$ 47.61	$ 48.52
Annual Net Value/(Cost)			$ 10.68	$ 11.15	$ 12.02	$ 13.04	$ 14.11	$ 14.82	$ 15.44	$ 16.29	$ 17.25	$ 18.28	$ 19.11	$ 20.02
Project 1398, VA, PJM, Q3 2021, 75 MW, 165,000 MWH/yr.	165,000		$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)			$ 39.22	$ 39.53	$ 40.29	$ 41.31	$ 42.39	$ 43.34	$ 43.76	$ 44.63	$ 45.56	$ 46.55	$ 47.45	$ 48.32
Annual Net Value/(Cost)			$ 10.22	$ 10.53	$ 11.29	$ 12.31	$ 13.39	$ 14.34	$ 14.76	$ 15.63	$ 16.56	$ 17.55	$ 18.45	$ 19.32
Project 1059, VA, PJM, Q4 2020, 50 MW, 107,000 MWH/yr.	107,000		$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50
PJM West Hub Value (LevelTen - OTCGH Forward Curve) (5)			$ 35.35	$ 35.68	$ 36.51	$ 37.43	$ 38.40	$ 39.22	$ 39.80	$ 40.57	$ 41.45	$ 42.33	$ 43.09	$ 43.94
Annual Net Value/(Cost)			$ 9.85	$ 10.18	$ 11.01	$ 11.93	$ 12.90	$ 13.72	$ 14.30	$ 15.07	$ 15.95	$ 16.83	$ 17.59	$ 18.44
Project 216, VA, PJM, Q2 2020, 80 MW, 182,000 MWH/yr.	182,000		$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80	$ 31.80
PJM Dominion Hub Value (LevelTen - OTCGH Forward Curve) (5)			$ 39.29	$ 39.49	$ 40.18	$ 41.23	$ 42.29	$ 43.38	$ 43.68	$ 44.58	$ 45.53	$ 46.44	$ 47.39	$ 48.27
Annual Net Value/(Cost)			$ 7.49	$ 7.69	$ 8.38	$ 9.43	$ 10.49	$ 11.58	$ 11.88	$ 12.78	$ 13.73	$ 14.64	$ 15.59	$ 16.47
Project 113, NC, PJM, Q1 2020, 100 MW, 226,000 MWH/yr.	226,000		$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)			$ 40.18	$ 40.29	$ 40.80	$ 41.83	$ 42.88	$ 44.00	$ 44.55	$ 45.28	$ 46.24	$ 47.20	$ 48.18	$ 49.11
Annual Net Value/(Cost)			$ 7.18	$ 7.29	$ 7.80	$ 8.83	$ 9.88	$ 11.00	$ 11.55	$ 12.28	$ 13.24	$ 14.20	$ 15.18	$ 16.11
Project 1092, VA, PJM, Q4 2020, 70 MW, 146,000 MWH/yr.	146,000		$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10	$ 33.10
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)			$ 39.34	$ 39.82	$ 40.69	$ 41.71	$ 42.79	$ 43.51	$ 44.13	$ 44.98	$ 45.98	$ 46.98	$ 47.81	$ 48.73
Annual Net Value/(Cost)			$ 6.24	$ 6.72	$ 7.59	$ 8.61	$ 9.69	$ 10.41	$ 11.03	$ 11.88	$ 12.88	$ 13.88	$ 14.71	$ 15.63
Project 774, VA, PJM, Q2 2020, 75 MW, 176,000 MWH/yr.	176,000		$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85	$ 32.85
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)			$ 39.12	$ 39.32	$ 40.01	$ 41.05	$ 42.11	$ 43.20	$ 43.50	$ 44.39	$ 45.34	$ 46.24	$ 47.19	$ 48.06
Annual Net Value/(Cost)			$ 6.27	$ 6.47	$ 7.16	$ 8.20	$ 9.26	$ 10.35	$ 10.65	$ 11.54	$ 12.49	$ 13.39	$ 14.34	$ 15.21
Project 39, VA, PJM, Q2 2021, 65 MW, 149,000 MWH/yr.	149,000		$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25	$ 34.25
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)			$ 39.07	$ 39.25	$ 39.94	$ 40.97	$ 42.03	$ 43.13	$ 43.43	$ 44.29	$ 45.28	$ 46.18	$ 47.12	$ 47.98
Annual Net Value/(Cost)			$ 4.82	$ 5.00	$ 5.69	$ 6.72	$ 7.78	$ 8.88	$ 9.18	$ 10.04	$ 11.03	$ 11.93	$ 12.87	$ 13.73
Wind Total Volume	1,193,000	47%												
Solar Total Volume	1,320,000	53%												

Figure A4-4 – 12-Year Ramp Rate to 90% - Portfolio Sourcing

Scenario #6ARC - 12 year ramp to 90% renewables, DCRPS Marketplace projects, Portfolio slice, OTCGH forward curve																
New procurement process determined																
First RFP / Project(s) Operational																
Second RFP / Project(s) Operational																
Third RFP / Project(s) Operational																
Fourth RFP / Project(s) Operational																
Fifth RFP / Project(s) Operational																
Sixth RFP / Project(s) Operational																
Seventh RFP / Project(s) Operational																
Eigth RFP / Project(s) Operational																
Ninth RFP / Project(s) Operational																
Tenth RFP / Project(s) Operational																
Eleventh RFP / Project(s) Operational																
Twelfth RFP / Project(s) Operational																
Cumulative % of Supply Under PPAs					8%	15%	23%	30%	38%	45%	53%	60%	68%	75%	83%	90%
Residential SOS																
Annual Residential + Commercial SOS Volume (MWH)	**2,800,000**															
Annual PPA Procurement Target Volume (MWH/yr.)			210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000		
Flowing PPA Supply (MWH)					210,000	420,000	630,000	840,000	1,050,000	1,260,000	1,470,000	1,680,000	1,890,000	2,100,000	2,310,000	2,520,000
Wind																
Project 1199, IL, MISO, Q4 2020, 150 MW, 468,000 MWH/yr.	**468,000**				$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00
MISO Indiana Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 29.48	$ 29.32	$ 29.43	$ 29.71	$ 30.24	$ 30.86	$ 31.35	$ 31.80	$ 32.43	$ 33.11	$ 33.78	$ 34.43
Annual Net Value/(Cost)					$ 2.48	$ 2.32	$ 2.43	$ 2.71	$ 3.24	$ 3.86	$ 4.35	$ 4.80	$ 5.43	$ 6.11	$ 6.78	$ 7.43
Project 1021, OH, PJM, Q2 2020, 200 MW, 200,000 MWH/yr.	**200,000**				$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00
PJM AEP Dayton Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 29.30	$ 29.85	$ 30.10	$ 29.76	$ 29.73	$ 29.48	$ 29.71	$ 30.31	$ 30.93	$ 31.55	$ 32.18	$ 32.80
Annual Net Value/(Cost)					$ 3.30	$ 3.85	$ 4.10	$ 3.76	$ 3.73	$ 3.48	$ 3.71	$ 4.31	$ 4.93	$ 5.55	$ 6.18	$ 6.80
Solar																
Project 1402, NC, PJM, Q4 2021, 75 MW, 169,000 MWH/yr.	**169,000**				$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.18	$ 39.65	$ 40.52	$ 41.54	$ 42.61	$ 43.32	$ 43.94	$ 44.79	$ 45.75	$ 46.78	$ 47.61	$ 48.52
Annual Net Value/(Cost)					$ 10.68	$ 11.15	$ 12.02	$ 13.04	$ 14.11	$ 14.82	$ 15.44	$ 16.29	$ 17.25	$ 18.28	$ 19.11	$ 20.02
Project 1398, VA, PJM, Q3 2021, 75 MW, 165,000 MWH/yr.	**165,000**				$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.22	$ 39.53	$ 40.29	$ 41.31	$ 42.39	$ 43.34	$ 43.76	$ 44.63	$ 45.56	$ 46.55	$ 47.45	$ 48.32
Annual Net Value/(Cost)					$ 10.22	$ 10.53	$ 11.29	$ 12.31	$ 13.39	$ 14.34	$ 14.76	$ 15.63	$ 16.56	$ 17.55	$ 18.45	$ 19.32
Project 1059, VA, PJM, Q4 2020, 50 MW, 107,000 MWH/yr.	**107,000**				$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50
PJM West Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 35.35	$ 35.68	$ 36.51	$ 37.43	$ 38.40	$ 39.22	$ 39.80	$ 40.57	$ 41.45	$ 42.33	$ 43.09	$ 43.94
Annual Net Value/(Cost)					$ 9.85	$ 10.18	$ 11.01	$ 11.93	$ 12.90	$ 13.72	$ 14.30	$ 15.07	$ 15.95	$ 16.83	$ 17.59	$ 18.44
Project 216, VA, PJM, Q2 2020, 80 MW, 182,000 MWH/yr.	**182,000**				$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50
PJM West Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.29	$ 39.49	$ 40.18	$ 41.23	$ 42.29	$ 43.38	$ 43.68	$ 44.58	$ 45.53	$ 46.44	$ 47.39	$ 48.27
Annual Net Value/(Cost)					$ 13.79	$ 13.99	$ 14.68	$ 15.73	$ 16.79	$ 17.88	$ 18.18	$ 19.08	$ 20.03	$ 20.94	$ 21.89	$ 22.77
Total Portfolio	**1,291,000**				$ 6.87	$ 7.06	$ 7.51	$ 8.05	$ 8.75	$ 9.37	$ 9.81	$ 10.48	$ 11.25	$ 12.06	$ 12.82	$ 13.58
Wind	**52%**															
Solar	**48%**															
Contracted Projects			Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice	Portfolio Slice		
Contracted Volume			210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000		
Flowing Volume					210,000	420,000	630,000	840,000	1,050,000	1,260,000	1,470,000	1,680,000	1,890,000	2,100,000	2,310,000	2,520,000
Financial Benefit					0.52	1.06	1.69	2.42	3.28	4.22	5.15	6.29	7.60	9.04	10.58	12.22

Figure A4-5 – 6-Year Ramp Rate to 90% - National Sourcing

	Annual Production Yr.1 - (MWH)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Scenario #8ARC - 6 year ramp to 90% renewables, National Marketplace projects, OTCGH forward curve																
New procurment process determined																
First RFP / Project(s) Operational																
Second RFP / Project(s) Operational																
Third RFP / Project(s) Operational																
Fourth RFP / Project(s) Operational																
Fifth RFP / Project(s) Operational																
Sixth RFP / Project(s) Operational																
Cumulative % of Supply Under PPAs					15%	30%	45%	60%	75%	90%						
Residential SOS																
Annual Residential + Commercial SOS Volume (MWH)	**2,800,000**															
Annual PPA Procurement Target Volume (MWH/yr.)			420,000	420,000	420,000	420,000	420,000	420,000								
Flowing PPA Supply (MWH)					420,000	840,000	1,260,000	1,680,000	2,100,000	2,520,000	2,520,000	2,520,000	2,520,000	2,520,000	2,520,000	2,520,000
Wind																
Project 1417, OK, SPP, Q4 2020, 150 MW, 608,000 MWH/yr.	**608,000**				$ 15.96	$ 15.96	$ 15.96	$ 15.96	$ 15.96	$ 15.96	$ 15.96	$ 15.96	$ 15.96	$ 15.96	$ 15.96	$ 15.96
SPP South Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 20.49	$ 21.27	$ 21.56	$ 22.03	$ 22.64	$ 23.14	$ 23.59	$ 23.90	$ 24.37	$ 24.87	$ 25.37	$ 25.88
Annual Net Value/(Cost)					$ 4.53	$ 5.31	$ 5.60	$ 6.07	$ 6.68	$ 7.18	$ 7.63	$ 7.94	$ 8.41	$ 8.91	$ 9.41	$ 9.92
Project 993, TX, ERCOT, Q4 2019, 150 MW, 590,000 MWH/yr.	**590,000**				$ 19.23	$ 19.23	$ 19.23	$ 19.23	$ 19.23	$ 19.23	$ 19.23	$ 19.23	$ 19.23	$ 19.23	$ 19.23	$ 19.23
ERCOT North Zone Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 23.42	$ 22.63	$ 21.90	$ 22.28	$ 22.90	$ 23.42	$ 23.75	$ 24.10	$ 24.62	$ 25.15	$ 25.68	$ 26.07
Annual Net Value/(Cost)					$ 4.19	$ 3.40	$ 2.67	$ 3.05	$ 3.67	$ 4.19	$ 4.52	$ 4.87	$ 5.39	$ 5.92	$ 6.45	$ 6.84
Solar																
Project 1063, TX, ERCOT, Q1 2020, 150 MW, 430,000 MWH/yr.	**430,000**				$ 18.45	$ 18.45	$ 18.45	$ 18.45	$ 18.45	$ 18.45	$ 18.45	$ 18.45	$ 18.45	$ 18.45	$ 18.45	$ 18.45
ERCOT South Zone Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 37.24	$ 35.64	$ 32.28	$ 33.22	$ 34.12	$ 34.95	$ 35.16	$ 35.81	$ 36.66	$ 37.45	$ 38.21	$ 38.69
Annual Net Value/(Cost)					$ 18.79	$ 17.19	$ 13.83	$ 14.77	$ 15.67	$ 16.50	$ 16.71	$ 17.36	$ 18.21	$ 19.00	$ 19.76	$ 20.24
Project 1402, NC, PJM, Q4 2021, 75 MW, 169,000 MWH/yr.	**169,000**				$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50	$ 28.50
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.18	$ 39.65	$ 40.52	$ 41.54	$ 42.61	$ 43.32	$ 43.94	$ 44.79	$ 45.75	$ 46.78	$ 47.61	$ 48.52
Annual Net Value/(Cost)					$ 10.68	$ 11.15	$ 12.02	$ 13.04	$ 14.11	$ 14.82	$ 15.44	$ 16.29	$ 17.25	$ 18.28	$ 19.11	$ 20.02
Project 1398, VA, PJM, Q3 2021, 75 MW, 165,000 MWH/yr.	**165,000**				$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00	$ 29.00
PJM Dominion Hub Power Value (LevelTen - OTCGH Forward Curve) (5)					$ 39.22	$ 39.53	$ 40.29	$ 41.31	$ 42.39	$ 43.34	$ 43.76	$ 44.63	$ 45.56	$ 46.55	$ 47.45	$ 48.32
Annual Net Value/(Cost)					$ 10.22	$ 10.53	$ 11.29	$ 12.31	$ 13.39	$ 14.34	$ 14.76	$ 15.63	$ 16.56	$ 17.55	$ 18.45	$ 19.32
Project 27, TX, ERCOT, Q4 2020, 150 MW, 419,000 MWH/yr.	**419,000**				$ 23.55	$ 23.55	$ 23.55	$ 23.55	$ 23.55	$ 23.55	$ 23.55	$ 23.55	$ 23.55	$ 23.55	$ 23.55	$ 23.55
ERCOT North Zone Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 35.54	$ 34.18	$ 32.20	$ 32.60	$ 33.53	$ 34.33	$ 34.62	$ 35.19	$ 36.01	$ 36.83	$ 37.61	$ 38.00
Annual Net Value/(Cost)					$ 11.99	$ 10.63	$ 8.65	$ 9.05	$ 9.98	$ 10.78	$ 11.07	$ 11.64	$ 12.46	$ 13.28	$ 14.06	$ 14.45
Project 1059, VA, PJM, Q4 2020, 50 MW, 107,000 MWH/yr.	**107,000**				$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50	$ 25.50
PJM West Hub Value (LevelTen - OTCGH Forward Curve) (5)					$ 35.35	$ 35.68	$ 36.51	$ 37.43	$ 38.40	$ 39.22	$ 39.80	$ 40.57	$ 41.45	$ 42.33	$ 43.09	$ 43.94
Annual Net Value/(Cost)					$ 9.85	$ 10.18	$ 11.01	$ 11.93	$ 12.90	$ 13.72	$ 14.30	$ 15.07	$ 15.95	$ 16.83	$ 17.59	$ 18.44
Wind Total Volume	**1,198,000**	48%														
Solar Total Volume	**1,290,000**	52%														
Contracted Projects			Project 1063(s)	Project 1417(W)	Project 1402(S) Project 1398(S)	Project 993(W)	Project 27(S)	Project 1059(S)								
Contracted Volume			430,000	608,000	334,000	590,000	419,000	107,000								
Flowing Volume					430,000	1,038,000	1,372,000	1,962,000	2,381,000	2,488,000	2,488,000	2,488,000	2,488,000	2,488,000	2,488,000	2,488,000
Financial Benefit																
First Year Projects ($/MWH of SOS)					**$ 2.89**	**$ 2.64**	**$ 2.12**	**$ 2.27**	**$ 2.41**	**$ 2.53**	**$ 2.57**	**$ 2.67**	**$ 2.80**	**$ 2.92**	**$ 3.03**	**$ 3.11**
Second Year Projects ($/MWH of SOS)						**$ 1.15**	**$ 1.22**	**$ 1.32**	**$ 1.45**	**$ 1.56**	**$ 1.66**	**$ 1.72**	**$ 1.83**	**$ 1.93**	**$ 2.04**	**$ 2.15**
Third Year Projects ($/MWH of SOS)							**$ 1.39**	**$ 1.51**	**$ 1.64**	**$ 1.74**	**$ 1.80**	**$ 1.90**	**$ 2.02**	**$ 2.14**	**$ 2.24**	**$ 2.35**
Fourth Year Projects ($/MWH of SOS)								**$ 0.64**	**$ 0.77**	**$ 0.88**	**$ 0.95**	**$ 1.03**	**$ 1.14**	**$ 1.25**	**$ 1.36**	**$ 1.44**
Fifth Year Projects ($/MWH of SOS)									**$ 1.49**	**$ 1.61**	**$ 1.66**	**$ 1.74**	**$ 1.86**	**$ 1.99**	**$ 2.10**	**$ 2.16**
Sixth Year Projects ($/MWH of SOS)										**$ 0.52**	**$ 0.55**	**$ 0.58**	**$ 0.61**	**$ 0.64**	**$ 0.67**	**$ 0.70**
Total Financial Benefit					**$ 2.89**	**$ 3.79**	**$ 4.73**	**$ 5.74**	**$ 7.76**	**$ 8.85**	**$ 9.18**	**$ 9.64**	**$ 10.25**	**$ 10.87**	**$ 11.45**	**$ 11.92**

APPENDIX 5

Standard Offer Service - Full text of the Code of the District of Columbia § 34–1509

CRI has highlighted sections of particular relevance to this study.

§ 34–1509. Standard offer service.

(a) Standard offer service is electricity supply made available on and after the initial implementation date to:

(1) Customers not yet allowed to choose an electricity supplier under the phase-in of customer choice under § 34-1502;

(2) Customers who contract for electricity with an electricity supplier, but who fail to receive delivery of electricity under such contracts;

(3) Customers who cannot arrange to purchase electricity from an electricity supplier; and

(4) Customers who do not choose an electricity supplier.

(b)(1) Standard offer service shall be provided by the electric company from the initial implementation date through February 7, 2005.

(2)(A) The rate cap specified in subparagraph (B) of this paragraph shall apply beginning on the initial implementation date and shall end on February 7, 2005.

(B)(i) Subject to the time limitation in subparagraph (A) of this paragraph, and except for the charges specified in sub-subparagraph (ii) of this subparagraph, the total rate charged to a customer receiving standard offer service shall not exceed the total of the rates authorized by the Commission and charged to the customer on December 31, 1999.

(ii) The rate cap specified in sub-subparagraph (i) of this subparagraph shall not apply to charges imposed for the recovery of costs under § 34-1511.

(3)(A) During the period in which the rate cap specified in paragraph (2)(B) of this subsection is in effect, the Commission shall have the authority to set, in a manner that is just, reasonable, and non-discriminatory, the rate charged to a customer receiving standard offer service.

(B) The Commission shall ensure that any rate cut promulgated under paragraph (2) of this subsection does not hinder the development of a competitive market for electricity supply.

(4) During the period in which the rate cap specified in paragraph (2)(B) of this subsection is in effect, the Commission may allow the recovery of any extraordinary costs based on the circumstances of the electric company if the Commission determines that the action is necessary and in the public interest.

(c) Before January 2, 2004, the Commission shall adopt regulations or issue orders establishing terms and conditions for standard offer service and for the selection of an electricity supplier or suppliers (retail, wholesale, or both) to provide standard offer service after February 7, 2005. The terms and conditions applicable to the selection of an electricity supplier or suppliers shall include:

(1) Protection against a standard offer service provider's failure to provide service;

(2) An appropriate rate design, subject to the restrictions in subsection (d) of this section;

(3) The appropriate length of a standard offer service contract awarded under subsection (d) of this section; and

(4) A contingency plan in the event of insufficient or inadequate bids; provided, that a contingency plan may award the standard offer service to the electric company or an affiliate of the electric company if it is in the public interest.

[NOTE: proposed CleanEnergy DC Omnibus Amendment Act of 2018 adds language here to require long-term purchases].

(d)(1) After the regulations or orders mandated by subsection (c) of this section are issued, the Commission shall conduct competitive bid procedures for the selection of a retail electricity supplier or suppliers to provide standard offer service for the District of Columbia after February 7, 2005; authorize the electric company, as a wholesale electricity supplier, to conduct competitive bid procedures to obtain third-party contracts to provide standard offer service for the District of Columbia after February 7, 2005; or both. If competitive bid procedures for the selection of a retail electricity supplier or suppliers to provide standard offer service are conducted by the Commission, the competitive selection of retail electricity supplier or suppliers to provide standard offer service shall occur before July 2, 2004. In conducting retail bid procedures or facilitating the wholesale bid process under this subsection, the Commission:

(A) Shall ensure that the price for standard offer service will not hinder the development of a competitive electricity supply market in the District of Columbia; and

(B) May, in its discretion, solicit the payment, by the retail electricity supplier or suppliers chosen to provide standard offer service, of a bid premium.

(2) Any bid premium collected by the Commission under this section shall be deposited into the Reliable Energy Trust Fund established under § 34-1514 [repealed].

(e) The Commission shall determine the threshold financial viability of wholesale bidders.

APPENDIX 6

Standard Offer Service - Full text of District of Columbia Municipal Regulations Chapter 15-41

CRI has highlighted sections of particular relevance to this study.

4100 GENERAL PROVISIONS; SCOPE, APPLICABILITY AND AVAILABILITY OF STANDARD OFFER SERVICE; ELIGIBILITY FOR STANDARD OFFER SERVICE

4100.1 The purpose of this chapter is to set forth the policies and procedures for the implementation of the "Retail Electric Competition and Consumer Protection Act of 1999," as amended.

4100.2 This chapter establishes the Public Service Commission of the District of Columbia ("Commission") Rules and Regulations Governing the Provision of Standard Offer Service ("SOS"), the terms and conditions for wholesale electric power supply procurement for SOS, reporting and monitoring procedures, pricing and true-up procedures, other services, and miscellaneous provisions and reservations. The procurement process is for full-requirements wholesale electric supply service to meet the SOS retail load. This chapter shall be cited as the "District of Columbia Standard Offer Service Rules."

4100.3 This chapter shall be applicable to the SOS Administrator to retail customers in the Electric Company's distribution service territory. This chapter also establishes the rules by which the SOS Administrator shall obtain electric supply for SOS pursuant to a competitive wholesale procurement process and will apply to wholesale bidders who compete for the provision of wholesale full requirements services to the SOS Administrator. This chapter also establishes the rules by which the SOS Administrator shall obtain electric supply from Community Renewable Energy Facilities ("CREFs") as defined in Subsection 4199.1 and as described in Subsections 4109.1 through 4109.3 pursuant to the Community Renewable Energy Amendment Act of 2013. The provisions of this chapter are promulgated pursuant to authority set forth in Sections 34-1509(c), 34-1518.01(b), 34-1518.01(c), and 34-1504(c)(7) of the D.C. Official Code.

4100.4 All Electric Company distribution customers are eligible for SOS from the SOS Administrator and are subject to the general terms and conditions of the Electric Company's tariffs and the Commission's regulations, as they may change from time to time subject to the Commission's approval or adoption of new regulations.

4100.5 SOS shall be available to: (1) customers who contract for electricity with a Competitive Electricity Supplier, but who fail to receive delivery of electricity under such contracts; (2) customers who cannot arrange to purchase electricity from a Competitive Electricity Supplier; and (3) customers who do not choose a Competitive Electricity Supplier.

4101 SELECTION OF WHOLESALE SOS PROVIDERS

4101.1 The Electric Company shall continue as the SOS Administrator for retail customers in the Electric Company's distribution service territory until such time as the Commission directs otherwise.

4101.2 The SOS Administrator shall obtain electric supply for SOS pursuant to a competitive wholesale procurement process and pursuant to the CREA. The procurement process shall solicit all of the electric supply for SOS customers except for the electric supply that is provided by CREFs.

4101.3 The specific procurement format, form of request, process, timeline, and evaluation process, evaluation criteria and process and model contract for electricity supply shall be submitted for Commission approval by the SOS Administrator by August 1 of the previous year**.** The SOS Administrator shall coordinate with other jurisdictions to ensure that bidding days do not coincide for multiple jurisdictions in the Mid-Atlantic area.

4101.4 Subject to the review and approval of the Commission, the SOS Administrator shall solicit for wholesale full requirements service pursuant to a Wholesale Full Requirements Service Agreement ("WFRSA") with the Wholesale SOS Providers, which shall include the provision of electric energy, energy losses, generation capacity, ancillary services and any other PJM- or FERC-approved services associated with the SOS Administrator's load obligation, except for network integration transmission service, which will be obtained by the SOS Administrator. The Wholesale SOS Provider shall be responsible for all congestion costs up to the delivery point at which the SOS Administrator takes the power to serve its SOS load.

4101.5 The SOS Administrator shall solicit seasonally differentiated summer and winter prices.

4101.6 Contracts for electricity supply may be of varied duration, as approved by the Commission, to stabilize prices for customers.

4102 COMPETITIVE WHOLESALE BID STRUCTURE

4102.1 The SOS Administrator shall procure full requirements service to meet its SOS obligations using a competitive wholesale procurement process described in this chapter, as amended from time to time and as adjusted for offsetting electric supply procured from CREFs, for each SOS Customer Group (as those SOS Customer Groups are defined in Subsection 4102.3), until the Commission orders, following the major policy review outlined in Subsection 4102.2 below, that an alternative SOS procurement process shall be implemented.

4102.2 The Commission will conduct a review of the SOS Administrator's SOS program every other year, beginning in 2010, to make any appropriate adjustments to SOS as competitive developments in the District of Columbia change. All adjustments shall be prospective and all contracts entered into prior to these changes shall remain in full force and effect pursuant to the contract terms.

4102.3 The SOS Administrator shall establish three (3) groups of customers ("SOS Customer Groups"):

(d) Residential Customers shall include customers served under Electric Company Rate Schedules: R, AE, R-TM, R-TM-EX, RAD, and Master Metered Apartment customers, subject to any revisions made to those tariff sheets made by the Commission;

(e) Small Commercial Customers shall include the customers served under Electric Company Rate Schedules: GS-LV non-demand, GS-3A non-demand, T, SL, TS, TN and SL-TN, subject to any revisions made to those tariff sheets made by the Commission; and

(f) Large Commercial Customers shall include all commercial customers except those defined as Small Commercial Customers.

4102.4 The SOS Administrator shall issue Requests For Proposals ("RFPs") to competitive wholesale bidders for contracts for the supply of SOS in order to maintain the following contract term balances for the various customer portfolios:

(a) Residential Customers: The SOS Administrator shall solicit fixed-price offers for terms of one year, two years, or three or more years. The SOS Administrator's portfolio shall contain contracts such that three or more year offers comprise at least forty percent (40%) of each year's portfolio, unless the Commission has directed the SOS Administrator to solicit fixed-price offers based on a different mix of terms. The SOS Administrator and other parties may propose alternative portfolios of supply options for consideration by the Commission. The SOS Administrator shall compile a portfolio of conforming offers consistent with the mix of terms determined by the Commission. The SOS Administrator shall select conforming offers to meet the Commission's percentage target(s) in accordance with the evaluation provision included in the RFP. Unless the Commission has directed otherwise, the final contract mix should include contracts of at least three years for no less than forty percent (40%) of the total load.

(b) Small Commercial Customers**:** The SOS Administrator shall solicit fixed price offers for Wholesale Full Requirements Service for some combination of one, two, and three or more year terms. The SOS Administrator shall compile a portfolio of one, two, and three or more year terms conforming offers such that at least forty percent (40%) of the load will be served under contracts of three or more year terms. The SOS Administrator shall select one, two, and three or more year conforming offers to meet this percentage target in accordance with the evaluation provision included in the RFP. The SOS Administrator and other parties may propose an alternative portfolio of supply options for consideration by the Commission; and

(c) Large Commercial Customers: The SOS Administrator shall solicit fixed price offers for Wholesale Full Requirements Service for one and/or two year terms.

The RFP shall alert the competitive wholesale bidders to the fact that final service requirements may be adjusted to accommodate offsetting electric supply obtained by the SOS Administrator from CREFs.

4102.5 The SOS Administrator shall continue to solicit offers for Wholesale Full Requirements Service for each SOS Customer Group until the Commission orders otherwise, subsequent to Commission review of the SOS procurement process.

4102.6 The SOS Administrator shall solicit wholesale bids for SOS supply using the existing rate structures of its existing rate classes. Nothing herein, however, precludes the SOS Administrator from filing for a different rate structure for any rate schedule or SOS

Customer Group, subject to Commission review and approval, and provided that any such changes, adjustments, alterations, or modifications do not change or impact existing WFRSAs.

4103 STANDARD OFFER SERVICE RETAIL RATES

4103.1 The retail rates to SOS customers will consist of the sum of the following components:

(a) The seasonally-differentiated and, if applicable, time-of-use differentiated load weighted average price of all awarded contracts for Wholesale Full Requirements Service for each SOS Customer Group;

(b) Retail charges designed to recover, on an aggregate basis, FERC-approved Network Integrated Transmission Service charges ("NITS") and related charges and any other PJM charges and costs incurred by the SOS Administrator directly related to the SOS Administrator's SOS load obligation for each SOS Customer Group;

(c) PJM Locational Marginal Price for energy in the Pepco District of Columbia sub-Zone, adjusted for ancillary service charges as specified in Subsection 906.4, for all unsubscribed electric supply purchased from CREFs;

(a) An administrative charge; and

(b) Applicable taxes.

4103.2 When the winning wholesale bidder(s) are selected, the SOS Administrator shall submit to the Commission: (1) the names of the winning bidders, which shall remain confidential subject to Subsection 4111.5 of this chapter, and (2) the retail rates for all the customer classes according to the Commission pre-approved time schedule. Such rates shall consist of all the components included in Subsection 4103.1. The filing required herein shall also include: (1) a detailed calculation and explanation of an administrative charge and (2) administrative charge true-up provisions.

4103.3 Parties to the proceedings can file comments within seven (7) calendar days and reply comments within twelve (12) calendar days of the SOS Administrator's submission of the retail rates and administrative charge pursuant to Subsection 4103.2. The Commission shall thereafter issue an Order approving or rejecting the retail rates and/or administrative charge. The SOS Administrator shall file a revised tariff setting forth the new retail rates and/or administrative charges within seven (7) calendar days of the Commission's Order approving those rates and charge.

4103.4 The Administrative Charge will be designed to recover the SOS Administrator's incremental costs for procuring and providing the service. Actual incremental costs shall include, but not be limited to, a proportionate share of SOS customer uncollectibles for each SOS Customer Group, Commission Consultant expenses (as described in Subsection 4110.1), wholesale SOS bidding expenses, working capital expenses related to SOS for each SOS Customer Group, wholesale supply transaction costs related to Wholesale SOS Provider administration and transmission service administration, wholesale payment and invoice processing, incremental billing process expenses, customer education costs, incremental system costs, costs related to the purchases of electric supply from CREFs and legal and regulatory filing expenses related to SOS requirements.

4103.5 Prior to the submission of bids, the SOS Administrator shall file a request with the Commission (with notice to all the Parties) for determination of the appropriate amount of its Administrative Charge to be included in the retail rates to SOS customers. In calculating the Administrative Charge, any return component on the Administrative Charge, if the inclusion of a return component is approved by the Commission, shall not be reflected for ratemaking purposes in the establishment of the Electric Company's distribution rates, including the determination of the Electric Company's return for providing distribution service.

4103.6 All customers eligible for SOS will be informed of the applicable SOS retail rates, to the extent practical, for the service at least two (2) months prior to the beginning of each service year. If it is not practicable to provide such notice, the SOS Administrator shall file with the Commission and serve upon the Parties notice of that fact, the reasons for the delay, and the expected date for the provision of such information.

4103.7 Retail prices to customers shall be adjusted at least twice a year to reflect seasonal pricing and other appropriate price changes. Prior to each year of SOS, the SOS Administrator shall file with the Commission, estimates of actual incremental costs for the upcoming year. Such costs will be collected from customers, on a load weighted average, subject to an annual adjustment to reflect actual costs.

4103.8 All investment, revenue and expenses associated with the provision of SOS by the Electric Company when serving as the SOS Administrator shall be separate from investment, revenues and expenses associated with the Electric Company's distribution service so that there will be no subsidization of the Electric Company's distribution rates.

4104 COMPETITIVE WHOLESALE BIDDING AND CONTRACTING PROCESS

4104.1 The SOS Administrator shall solicit offers for Wholesale Full Requirements Service via the RFP approved by the Commission. The SOS Administrator shall remain the NITS provider and shall be the designated PJM Load Serving Entity ("LSE") for all SOS. The SOS Administrator, as the PJM LSE, shall provide the rights to nomination and make available to the Wholesale SOS Providers all Firm Transmission Rights/Auction Revenue Rights ("FTR/ARRs") to which it has rights pursuant to the PJM procedures applicable to FTR and ARRs.

4104.2 The SOS Administrator shall solicit seasonally differentiated and, if applicable, time-of-use differentiated prices. In the case of multi-year-term contracts, prices shall, in addition, be annually specified. The solicitation shall be conducted through as many as four bidding rounds, as specified in the RFP.

4104.3 The total load associated with each SOS Customer Group shall be divided into bid blocks of approximately 50 MW to promote diversity of supply and reliable supply contract performance. Each bid block shall represent a percentage of the total SOS load that each Wholesale SOS Provider will be obligated to supply for the term of the contract regardless of changes in the magnitude of the total load for that SOS Customer Group. The size of the total load may vary from the 50 MW guideline for a particular group if the total load associated with a specific SOS Customer Group indicates that such variation is warranted.

One reason for a variation may be to accommodate electric supply acquired from CREFs as described in Subsection 4109.1. The SOS Administrator may alter the target size of the bid blocks by requesting permission to do so at the same time as it informs the Commission of its procurement plan, but only if it has reason to believe that the change would lead to more competitive offers.

4104.4 SOS service years shall continue annually beginning on June 1 of each year and ending on May 31 of the following year, consistent with PJM planning periods, until modified by Commission Order.

4104.5 Potential Wholesale SOS Providers must demonstrate their qualifications to provide Wholesale Full Requirements Service by providing proof that they are qualified to participate in the PJM Markets and have all the necessary FERC authorizations to enter into wholesale energy contracts. Furthermore, the RFP and WFRSA shall specify the financial credit requirements that potential or actual Wholesale SOS Suppliers must demonstrate.

4104.6 The SOS Administrator's RFP will include specific forms of bid request, evaluation plan, and the WFRSA. The evaluation plan contained in the RFP will specify that all bids to serve the load associated with a specific SOS Customer Group and for a specific contract length will be compared on a discounted price basis to select the lowest cost winning bids.

4104.7 Upon completion of the bid evaluation process, the SOS Administrator will notify the winning bidders and execute a WFRSA with each winning bidder. Such contract execution will be contingent, however, on Commission approval of the bid awards, contracts and credit support provisions therein. The contract(s) will be deemed approved by the Commission unless the Commission orders otherwise within two (2) business days following their submission. Winning bidders will receive the actual prices in their offers for each year of the term of their supply contract. Winning bidders will not be permitted to revise prices or any other terms and conditions of the WFRSA, except as provided for in the WFRSA.

4105 ESTABLISHMENT AND RE-ESTABLISHMENT OF STANDARD OFFER SERVICE; CUSTOMER SWITCHING RESTRICTIONS

4105.1 SOS shall be provided to any customer who purchases a new service within the District of Columbia and who does not obtain electric generation service from a Competitive Electricity Supplier at that time. There shall be no fee for a customer to establish SOS in this manner.

4105.2 Any customer taking service from a Competitive Electricity Supplier may terminate service with the Competitive Electricity Supplier and elect SOS upon notice to the Electric Company and the SOS Administrator as required by Subsection 4105.9.

4105.3 Any customer taking service from a Competitive Electricity Supplier who defaults may terminate service with the defaulting Competitive Electricity Supplier upon notice to the Electric Company and the SOS Administrator as required by Subsection 4105.9.

4105.4 Any customer who is slammed or switched to a Competitive Electricity Supplier by mistake can terminate service with the Competitive Electricity Supplier upon notice to the Electric Company and the SOS Administrator as required by Subsection 4105.9, and such customer shall be returned to the service that the customer was receiving prior to being slammed or the mistake occurring as if the slamming or the mistake had not occurred.

4105.5 All residential customers shall be eligible to switch from SOS to Competitive Electricity Suppliers and return to SOS without restrictions.

4105.6 If a non-residential customer who has elected to purchase generation services from a Competitive Electricity Supplier subsequently returns to SOS, such non-residential customer shall be obligated to remain on SOS for a minimum term of twelve (12) months, provided, that in the case of a non-residential customer who returns to SOS as a result of a default by that non-residential customer's Competitive Electricity Supplier, such non-residential customer may within a grace period of three full billing cycles thereafter elect to purchase or contract for generation services from another Competitive Electricity Supplier or elect to receive service from the SOS Administrator at Market Price Service rates in which event the minimum term of twelve (12) months does not apply. A Competitive Electricity Supplier default occurs when the PJM Interconnection L.L.C. notifies the PJM members that the Competitive Electricity Supplier is in default.

4105.7 A non-residential customer who ceases to receive generation services from a Competitive Electricity Supplier may elect to receive service from the SOS Administrator at Market Price Service rates rather than Standard Offer Service rates. The minimum stay provisions stated in Subsection 4105.6 shall not apply to customers receiving service under Market Price Service rates. The Market Price Service rates shall be set in accordance with a tariff previously filed and approved by the Commission. The tariff shall contain a formula that reflects only the following components, or their functional equivalents in the future: the PJM locational marginal price for energy for the Electric Company zone, the PJM posted and verifiable market capacity price, transmission, ancillary services, line losses, appropriate taxes and a fixed retail adder of x mills per kWh. (The amount of the retail adder will be determined in the administrative cost proceeding.) The Market Price Service rates may vary by customer class and reflect actual costs.

4105.8 The contract provisions and exit fees of the Competitive Electricity Supplier remain valid and shall be enforced before a customer will be permitted to switch to SOS or another Competitive Electricity Supplier.

4105.9 Notice of Transfers; Transfer of Service; Bill Calculation:

(a) Notice of Transfer into SOS: A customer who intends to transfer into SOS shall do so by notifying the Electric Company and the SOS Administrator or by canceling service with its Competitive Electricity Supplier.

(b) Transfer into SOS: If the customer notifies the Electric Company and the SOS Administrator no less than seventeen (17) days before the customer's next normally scheduled meter read date, the Electric Company and the SOS Administrator shall transfer the customer on the customer's next meter read date. Otherwise, transfer will occur on the following meter read date. The Electric Company and the SOS Administrator shall accommodate the request to the greatest extent practicable.

(c) Notice of Transfer out of SOS: Notice that a SOS customer will terminate SOS and obtain service from a Competitive Electricity Supplier shall be provided to the

Electric Company and the SOS Administrator by the customer's Competitive Electricity Supplier pursuant to Chapter 3 of Title 15 of the District of Columbia Municipal Regulations; and

(d) Transfer out of SOS: If the Competitive Electricity Supplier notifies the Electric Company and the SOS Administrator no less than seventeen (17) days before the customer's next meter read date, the Electric Company and the SOS Administrator shall transfer the customer on the customer's next meter read date. Otherwise, transfer will occur on the subsequent meter read date.

4106 FINANCIAL CAPABILITY REQUIREMENTS

4106.1 Financial capability requirements shall be imposed on Wholesale SOS Providers and shall be consistent with provisions established herein.

4106.2 Each Wholesale SOS Provider shall obtain and file with the Commission a bond, a letter of credit, or a corporate guarantee that will provide assurances of financial integrity and funding for replacement service in the event that the Wholesale SOS Provider fails to provide for uninterrupted service. If a corporate guarantee is obtained, it must conform to the Commission-approved form.

4106.3 The amount of the financial capability requirement for the Wholesale SOS Provider in the Electric Company's service territory shall be equal to fifteen (15) percent of the Wholesale SOS Provider's bid obligation for the SOS class(es) the provider is awarded, and expected to serve, in the Electric Company's service territory.

4106.4 The amount of the financial capability requirement shall be commensurate with the remaining outstanding bid obligation of the Wholesale SOS Provider throughout the term of the Wholesale SOS Provider's awarded contract period, and reduced annually from the initial amount determined at the beginning of the term of the Wholesale SOS Provider's service.

4106.5 The proceeds of the bond, or letter of credit, or corporate guarantee, as necessary, shall be payable to the SOS Administrator to whom the wholesale bidder is obligated to provide service. The proceeds of the bond, letter of credit, or corporate guarantee shall be used only to defray the additional costs of replacement SOS in the event of interrupted service. For purposes of this provision, additional costs are all costs that are incurred or will be incurred to acquire replacement SOS, including supply and administrative costs, through the remaining SOS term that exceed the amounts paid or to be paid by SOS customers at the SOS rates in effect at the time of the Commission's declaration of a Wholesale SOS Provider's default.

4106.6 A corporate guarantee permitted by Subsections 4106.2, 4106.3, and 4106.4, may be issued by an affiliate of the Wholesale SOS Provider or a third party that meets the financial credit requirements set forth in Subsections 4106.2, 4106.3, and 4106.4.

(a) The corporate guarantee must meet all of the requirements of Subsections 4106.2, 4106.3, and 4106.4, and shall be unconditional and irrevocable and provide for payment within five (5) business days for the period of the standard offer term.

(b) A corporate guarantee may be used to satisfy the requirement of Subsections

4106.2, 4106.3, and 4106.4, if the corporate guarantor meets the following financial qualifications and capabilities:

(1) The senior unsecured debt obligations of the guarantor are publicly rated, at a minimum, "BBB-" from S&P or Fitch, or "Baa3" from Moody's;

(2) The total assets of the guarantor are at least 5.0 times the amount of the corporate guarantee amount required by Subsections 4106.2, 4106.3, and 4106.4; and

(3) The total common equity of the guarantor is at least 2.5 times the amount of the corporate guarantee amount required by Subsections 4106.2, 4106.3, and 4106.4.

(c) If a corporate guarantor's senior unsecured debt obligations are rated by: (i) two of the agencies listed in Subsection 4106.6(b)(1), the guarantor's rating will be determined by the lower assigned rating; or (ii) all three of the agencies listed in Subsection 4106.6(b)(1), two of those agencies must have assigned ratings equal to or higher than the required ratings described above.

(d) If, at any time, the senior unsecured debt obligations of the corporate guarantor fail to meet the requirements of Subsection 4106.6(b), the corporate guarantor or the Wholesale SOS Provider shall immediately notify the Commission in writing.

(e) If the corporate guarantor fails to meet any of the financial capability requirements, the Commission may, at its option, require the Wholesale SOS Provider to post a bond or file a letter of credit as described in Subsections 4106.2, 4106.3, and 4106.4.

4106.7 If at any time during the term of the supplier agreement between the Wholesale SOS Provider and the SOS Administrator, the SOS Administrator's credit rating is downgraded below investment grade, as defined in Section 4199, the Wholesale SOS Provider has the right to require the SOS Administrator to make payments to the Wholesale SOS Provider on an accelerated basis during the downgrade period. Payments made under the acceleration clause may be made on a weekly basis.

4107 REPORTING REQUIREMENTS AND TRUE UP PROVISIONS

4107.1 Within ninety (90) days of the conclusion of each year of SOS bidding, the SOS Administrator shall submit a report to the Commission on its wholesale electric supply procurement process and results, SOS retail prices produced, on the aggregated SOS enrollment activity for each service class (including the number of customers, megawatt peak load, megawatt hour energy and switching to and from the service), a report on the amount of electric supply acquired from CREFs during the previous year, and a report of all true-ups conducted for that year. This requirement is not intended to replace or supersede any other reporting requirements imposed by the Commission on the SOS Administrator.

4107.2 If the SOS Administrator conducts wholesale bidding for a type of service on the basis of aggregated rate classes, the SOS Administrator shall make any needed true-ups on an aggregated basis.

4107.3 In addition to the other true-ups described herein, the SOS Administrator shall true-up its total costs for providing each type of service (Residential, Small Commercial, and Large Commercial) with its total billed revenues for that service. If the service type is still being provided when the true-up is completed, rates will be adjusted to reflect any over- or under-recoveries established in the true-up. In the event that there is any net over- or under-collection at the end of any type of service (Residential, Small Commercial, Large Commercial), the balance will be paid or collected through a mechanism to be determined in accordance with the procedures set forth in Subsection 4107.13. All retail price changes resulting from the true-up filings shall be reviewed annually by the Commission.

4107.4 The SOS Administrator will conduct the true-ups described herein to reflect the start of summer rates and concurrent with the start of non-summer rates. The SOS Administrator may conduct more frequent true-ups if it so chooses. Any revisions to retail electric rates resulting from the application of the true-up provisions shall be reflected in the prices posted on the Electric Company's web page. The true-ups are subject to audit by the Commission.

4107.5 The SOS Administrator shall true-up its billings to retail customers for services provided pursuant to Subsection 4103.1 against its payments to Wholesale SOS Providers and CREFs. The SOS Administrator shall also true-up its billings to retail customers to reflect any net damages recovered by the SOS Administrator from a defaulting Wholesale SOS Provider in accordance with Subsection 4111.3. The Commission will audit true-ups annually. In the event that there is any net over- or under-collection at the end of any type of service (Residential, Small Commercial, Large Commercial), the balance will be paid or collected through a mechanism to be determined in accordance with the procedures set forth in Subsection 4107.13.

4107.6 For the purpose of determining such true-up, the SOS Administrator's payments to its Wholesale SOS Providers shall exclude payments made with respect to the upward adjustment in a Wholesale SOS Provider's load arising from the activation of the Electric Company's load response programs and shall exclude any downward adjustment to a Wholesale SOS Provider's load arising from the SOS Administrator's acquisition of energy from a CREF.

4107.7 The retail price to Residential, Small Commercial, and Large Commercial customers posted pursuant to Subsection 4103.7 shall not change until after the first billing cycle following the start of service. Any difference between the SOS Administrator's incremental cost for serving SOS load and the SOS Administrator's revenue from serving SOS load based on the awarded bid prices shall be included as part of the retail rate true-up.

4107.8 Price Elements - Subsection 4103.1 shall include the additional costs (if any) that a Wholesale SOS Provider incurs in meeting any future statutory renewables requirements with respect to Residential, Small Commercial, and Large Commercial SOS. In the event that legislation is enacted that provides for a renewable energy resource requirement during the term of any WFRSA that has already been executed, Wholesale SOS Providers under the WFRSA may pass through their commercially reasonable additional costs, if any, associated with complying with the new requirement.

4107.9 If at any time any additional price elements resulting from a change in law and directly related to the SOS are identified by the SOS Administrator or a Wholesale SOS Provider, the SOS Administrator and/or the Wholesale SOS Provider may file a request with the Commission (with notice to all the Parties) for approval of recovery of those costs and, to the extent the costs are found to be incurred because of a change in law in connection with the provision of SOS and are prudently incurred as determined by the Commission, the costs will thereafter be included in the service price.

4107.10 The net costs included in retail prices pursuant to Subsection 4103.1(b) shall be recovered on a cents/kWh basis (energy basis) for non-demand tariff schedules and/or on a $/kW basis (demand basis) for demand tariff schedules. However, the SOS Administrator may request Commission approval to use alternate rate designs to recover NITS-related costs. The SOS Administrator may true-up its billings to retail customers for transmission services provided pursuant to Subsection 4103.1(b) against its payments for these services to PJM. The Commission may audit these true-ups annually. In the event that there is any net over- or under-collection at the end of any type of service (Residential, Small Commercial, Large Commercial), the balance will be paid or collected through a mechanism to be determined in accordance with the procedures set forth in Subsection 4107.13.

4107.11 To the extent not already recovered through the PJM Network Integration Transmission Service charges, any future surcharges assessed to network transmission customers for PJM-required transmission enhancements pursuant to the PJM Regional Transmission Expansion Plan, or for transition costs related to elimination of through-and-out transmission charges will be included in the charges under Subsection 4103.1(b). Pursuant to the WFRSA, the Wholesale SOS Providers bear the risk of any other changes in PJM products and pricing during the term of their WFRSAs. However, if there are any other new FERC-approved PJM transmission charges or other new PJM charges and costs charged to network transmission customers, the SOS Administrator may recover them through retail rates:

(a) The SOS Administrator will file with the Commission, and provide notice to all parties to the proceeding, a request for approval to recover such new charges through the SOS Administrator's retail rates under Subsection 4103.1(b); and

(b) The Wholesale SOS Provider will charge the SOS Administrator only for those new costs that the Commission determines may be recovered in rates by the SOS Administrator. In no event will the SOS Administrator bear the risk of any changes in regulation or PJM rules related to such costs or charges. Also, in no event shall any PJM charges to other than network transmission customers be recovered through the SOS Administrator's retail transmission rates for SOS service, except to the extent (if any) provided in Subsection 4103.1.

4107.12 The actual administrative costs for a given SOS year shall be used to true-up the estimated administrative costs for that same year, and any over- or under-collection of costs shall be applied to the estimated administrative costs for the next SOS program year for each SOS Customer Group. The Commission may audit such true-ups annually.

4107.13 At the end of any SOS period for a Customer Group, and after actual costs incurred by the SOS Administrator pursuant to Subsection 4103.1 have been determined, the parties to the proceeding will agree upon a mechanism with respect to actual costs, to return any over-collection to, and to collect any under-collection from, all active customers who would have been eligible for the service type at the conclusion of any service type period. If the parties to the proceeding fail to agree within a reasonable period, the matter will be submitted to the Commission for decision.

4107.14 Within ninety (90) days of the conclusion of each year's SOS bidding, the SOS Administrator shall submit a report to the Commission that details the value of the payments made to each Subscriber Organization for unsubscribed energy showing the price and the amount of unsubscribed energy underlying the payments for unsubscribed energy on a monthly basis.

4108 BID DOCUMENTS AND INFORMATION PROVIDED BY THE SOS ADMINISTRATOR TO POTENTIAL BIDDERS

4108.1 The Request For Proposal ("RFP") is the document pursuant to which the SOS Administrator shall solicit Wholesale Full Requirements Service to meet its SOS obligations. The RFP shall include the bid request process, the bid evaluation methodology, the timeline for the RFP process, and the following five appendices:

(a) Expression of Interest Form;

(b) Confidentiality Agreement;

(c) Credit Application;

(d) Bid Form Spreadsheets; and

(e) Binding Bid Agreement.

4108.2 The SOS Administrator shall provide to potential wholesale SOS bidders the following actual and historical information for the thirty-six (36) months preceding the month in which the data is to be submitted to the Commission. The SOS Administrator shall provide such data on its RFP website on a date to be specified by the Commission.

(a) Monthly and hourly demand, energy consumption and load profile data, as defined by the Commission, aggregated for each SOS customer class. For Large Commercial customers, if an individual customer's load data will be disclosed, customer written consent is required;

(b) Number of customers in each SOS customer class and the number of customers taking SOS within each customer class;

(c) Representative load shapes for each of the SOS Administrator's profile group and sub-groups by month, provided that if an individual customer's load shape will be disclosed, written customer consent is required;

(d) Hourly delivery data;

(e) Billing determinants on electronic spreadsheets;

(f) System losses;

(g) The amount of electric supply acquired from CREFs and the total capacity of all authorized CREFs; and

(h) Other information as determined by the Commission to be necessary or useful to wholesale SOS bidders.

4108.3 The general requirements and conditions for information submitted by the SOS Administrator to potential wholesale SOS bidders are as follows:

(a) Aggregate data: All information required to be provided by Subsection 4108.2 shall be provided on an aggregate class basis. Individual customer information shall not be provided without the customer's written consent.

(b) Historic Data Period: All information provided will reflect usage during the most recent thirty-six (36) month period, where available. Information describing factors that would cause the information to be unrepresentative of electricity usage during the SOS period shall also be provided.

(c) Due Care; Corrections: The SOS Administrator shall use due care in compiling the required information with the understanding that bidders will be relying on the data to formulate SOS bids. The SOS Administrator shall have the duty to correct any inaccuracies promptly upon discovery.

(d) Affiliated Interests: The SOS Administrator shall not provide any information to an affiliated wholesale SOS bidder that is not provided to all potential wholesale SOS bidders. The SOS Administrator must comply with the code(s) of conduct adopted by the Commission.

(e) Electronic Form; Standard Software: The SOS Administrator shall provide all information in electronic form usable by standard personal computer software packages; and

(f) Scope and Format: The Commission will determine the scope and detail of the information required by Subsections 4108.2, 4108.3(a), 4108.3(b), and 4108.3(e).

4109 DISTRIBUTION LEVEL GENERATION

4109.1 Community Renewable Energy Facilities ("CREFs") may provide electric supply to the SOS Administrator that shall be used to offset SOS purchases from Wholesale SOS Providers. All electric supply provided by CREFs shall become the property of the SOS Administrator, but shall not be counted toward the SOS Administrator's total retail sales for purposes of the Renewable Energy Portfolio Standard Act of 2004, effective April 12, 2005 (D.C. Law 15-340; D.C. Official Code §§ 34-1431 *et seq.*).

4109.2 If the electric production of a CREF is fully subscribed, the SOS Administrator shall pay the CREF through a CREF Community Net Metering ("CNM") credit on the accounts of all of the CREF's Subscribers. The SOS Administrator shall make no additional payment to the CREF.

4109.3 If the electrical production of a CREF is not fully subscribed, the SOS Administrator shall pay the CREF for the subscribed energy through a CNM credit on the accounts of all of the CREF's Subscribers and shall purchase the unsubscribed energy produced by the CREF at the PJM Locational Marginal Price for energy in the PEPCO District of Columbia sub-Zone, adjusted for ancillary service charges as specified in Subsection 906.4. The SOS Administrator shall pay the Subscriber Organization for the purchased energy on a monthly basis consistent with Subsections 906.4 and 907.9.

4109.4 Transactions identified in Subsections 4109.1 through 4109.3 are outside of the WFRSA and not part of the Wholesale Full Requirement Service.

4109.5 The SOS Administrator shall file with the Commission for approval a draft of a contract to be used by the SOS Administrator to acquire energy generated by a CREF from a Subscriber Organization within forty-five days of the date this revised rule becomes effective as set out in the Notice of Final Rulemaking published in the *D.C. Register*.

4110 MARKET MONITOR CONSULTANT

4110.1 The Consultant RFP is the document to be issued to hire the Commission's Market Monitoring Consultant ("Consultant"). The SOS Administrator shall procure and pay for an independent consultant hired pursuant to the Consultant RFP. The Consultant shall be responsible for monitoring all aspects of the procurement of the SOS services. Specifically:

(a) The Consultant shall be selected by, shall take its direction from, and shall provide its consultation and work products to the Commission.

(b) The costs incurred by the SOS Administrator in hiring the Consultant may be included in the SOS Administrator's incremental costs and may be recovered through the Administrative Charge, subject to Commission review and approval.

(c) The Consultant shall provide the Commission and the Office of the People's Counsel with a final report as to each supply procurement and award.

(d) The Commission shall determine the qualifications of and evaluate all bidders. The Commission shall further direct the SOS Administrator, in writing, as to which bidder to award a contract for consulting service and the terms and conditions of that contract with the exception of the terms and conditions specifically described in this Section. The SOS Administrator shall execute the contract with the Consultant no later than four (4) weeks prior to the date of the initial pre-bid conference. The SOS Administrator shall be required to pay only for work that the Consultant does in reviewing the SOS Administrator's compliance with Section 4104 and any other work that the Commission asks the Consultant to perform.

(e) The contract term for the contract between the SOS Administrator and the Consultant shall be for one-year, with an option to extend the contract for two (2) additional one-year terms. The option(s) shall be exercised by the Commission in its sole discretion; and

(f) Prior to the expiration of the initial contract awarded under this section, the second and subsequent consultant services contracts shall be awarded and administered consistent with Subsections 4110.1(a)-(e) herein.

4111 MISCELLANEOUS PROVISIONS

4111.1 The SOS Administrator may at any time request Commission approval to make changes in the Electric Company's tariffs. However, to the extent that those tariff changes would require conforming changes to either the RFP, the WFRSA generally, or any WFRSA that may be in effect from time to time:

(a) No such tariff changes may alter the rights and obligations of any Wholesale SOS Provider with respect to any WFRSA for which an RFP has already been issued, unless the Wholesale SOS Provider consents to have its rights or obligations changed;

(b) The SOS Administrator shall serve notice of the requested tariff change and copies of the proposed conforming changes to the RFP and/or WFRSA on all parties; and

(c) Any such tariff changes must be consistent with the regulations, orders or other obligations to which the SOS Administrator is subject.

4111.2 If, after conducting the bid procedures in accordance with the RFP, the SOS Administrator still has SOS load that has not been awarded to a Wholesale SOS Provider and cannot be supplied by CREFs, then:

(a) The SOS Administrator shall initially supply the unserved load by purchasing energy and all other necessary services through the PJM-administered markets, including but not limited to the PJM energy, capacity, and ancillary services markets, and any other service required by PJM to serve such unserved load, and shall include all the costs of such purchases in the retail rates charged for the service for which the purchases are made.

(b) Within five (5) business days of it being determined by the SOS Administrator that the load is unserved, the SOS Administrator shall convene a meeting of all parties to the proceeding and Commission staff to discuss alternative ways to fill the unserved load, including but not limited to a rebid or a bilateral contract. The meeting process will conclude within ten (10) business days of the load being determined to be unserved, and within twenty (20) calendar days of it being determined that the load is unserved, the SOS Administrator shall file with the Commission, and serve upon the all parties to the proceeding, any proposal it has for serving the load in lieu of the procedure set forth in Subsection 4111.2(a); and

(c) The Commission will resolve the SOS Administrator's filing on an expedited basis. Any alternative means that the Commission approves will expressly provide that the SOS Administrator's costs for filling the load will be recovered in retail rates in the same manner as all other charges pursuant to Subsection 4103.1. Until the Commission approves an alternate means of filling the load, Subsection 4111.2(a) will apply.

4111.3 If any load is left unserved after a Wholesale SOS Provider defaults:

(a) The SOS Administrator shall initially supply the defaulted load by purchasing energy and all other necessary services through the PJM-administered markets, including but not limited to the PJM energy, capacity, and ancillary services markets, and any other service required by PJM to serve such defaulted load, and shall include all the costs of such purchases, net of any offsetting recovery from the defaulting Wholesale SOS Provider, in the retail rates charged for the service for which the purchases are made; and

(b) As soon as practicable after it is determined by the SOS Administrator that the load is unserved, the SOS Administrator shall file with the Commission a plan to fill the remaining term of the defaulted WFRSA. Such a plan shall be submitted to the Commission within ten (10) business days after a Wholesale SOS Provider default. Until the Commission approves a plan to fill the remaining term of the defaulted WFRSA, Subsection 4111.3(a) will apply.

4111.4 Access to confidential information relating to the SOS Administrator's procurement of SOS power supply will be governed by the OPC Confidentiality Agreement, the Consultant's Confidentiality Agreement contained in the Bidder RFP, and the Confidentiality Agreement contained in the RFP and the confidentiality provisions of the WFRSA (collectively the "Confidentiality Agreements").

4111.5 Ninety (90) days following the Commission's approval of the selection of winning bidders for the final tranche, the Commission will disclose upon request (a) the total number of bidders, and (b) the names of the winning bidders.

APPENDIX 7

SOS Administrative Charge

A shift in SOS procurement from the current FRS model to a PPA model bases could affect the Administrative Charge component of SOS. This Appendix provides background on the Administrative Charge as a starting point for a further evaluation.

For the SOS rating period of June 1, 2018 through May 31, 2019, the Administrative Charges for each class of SOS service are as follows:

- $.0030 per kWh for Residential SOS
- $.0045 per kWh for Small Commercial SOS
- $.0050 per kWh for Large Commercial SOS

The Administrative Charge is comprised of the following components:

- Incremental costs
- Uncollectibles less late payment charges
- Cash working capital costs
- SOS Administrator margin
- Adder

Across all three customer classes, the total Administrative Charges expected to be collected during the 2018/2019 SOS service period are approximately $10,000,000.[113]

<u>Incremental costs</u>

As shown in Figure A7.1, incremental costs are those specifically associated with executing the SOS bidding process and managing the SOS program. In total, incremental costs for the 2018/2019 rating period are expected to be slightly less than $1,000,000. All of these cost elements would need to be reevaluated and would be subject to change with a shift in SOS procurement strategy.

[113] See Pepco filing in FC 1017, February 12, 2018, Attachment D, Page 1 of 10 Column J for Administrative Charge rates, and Page 1A for Forecasted kWh

Figure A7.1[114] - Pepco Incremental Cost Estimate

Potomac Electric Power Company
District of Columbia
Formal Case No. 1017
Incremental Cost of SOS - Year 14 (6/1/18 - 5/31/19)

Estimated

Cost Item	Estimated Annual	TOTAL
Commission Consultant Expenses	$ 180,000	$ 180,000
Architect Solutions - Software Contactor	20,000	20,000
Wholesale Bidding Expenses	530,000	530,000
Wholesale Supply Transaction Costs	150,000	150,000
Wholesale Payment and Invoice Processing	70,000	70,000
Incremental Billing Expenses	1,000	1,000
Customer Education Costs	1,000	1,000
Incremental Annual Legal Expenses	5,000	5,000
Total Incremental Costs	$ 957,000	$ 957,000

Uncollectibles less late payment charges

For the 2018/2019 rating period, uncollectible costs for SOS service net of late payment charges received are expected to be approximately $650,000, in line with recent experience.[115]

It seems reasonable to expect that uncollectibles experience will not change materially with the move toward PPA-based SOS. If the trajectory of future SOS costs is moderated by the long-term PPA contracts, this may help SOS customers to better afford their bills. That said, there is no clear analytical basis in regulatory filings for forecasting an improvement in actual uncollectible experience as a function of SOS prices, and none is assumed in this study.

114 Pepco filing in FC 1017, February 12, 2018, Attachment D, Page 7 of 10
115 Ibid Attachment D, Page 1 of 10 Column E for Net Uncollectible Expense Rates, and Page 1A for Forecasted kWh

Cash Working Capital Costs

Cash working capital (CWC) is used to finance the lag between wholesale power supply payments and the receipt of the corresponding revenues from SOS customers. Including an appropriate gross up for taxes on the return on this capital, costs are expected to be approximately $1,000,000 for the 2018/2019 rating period.[116] Note that this is lower than historical annual costs due to lower tax rates.[117]

CWC will need to be reevaluated to the extent that monthly payment terms under PPA contracts differ from the terms for the current FRS purchases. In addition, a greater amount of purchasing directly from PJM (e.g. for spot market power, capacity, ancillaries) could affect CWC requirements since PJM bills for its services weekly.

Under the Wholesale Full Requirements Service Agreement form document currently in use for SOS procurements,[118] there is no performance assurance required of Pepco as the buyer. It is possible that Pepco could be required to post such assurance under long-term PPA contracts, in some combination of cash, letters of credit, or parent guarantees. This could lead to additional CWC requirements beyond those needed to finance receivables lag.

SOS Administrator Margin

The largest component of the Administrative Charge is "utility return" or "margin". As decided by the Commission in 2017[119], beginning June 1, 2018 Pepco will receive a fixed annual return of $6,101,625 (including gross up for taxes). SOS customers will be billed on per kWh bases to recover this return, with any over or undercollection subject to true-up. The per kWh billing rates are:

- $.0015 per kWh for Residential SOS
- $.0020 per kWh for Small Commercial SOS
- $.0030 per kWh for Large Commercial SOS

In Order 19431, issued in August 2018 commencing the biennial review of the SOS procurement model, the Commission noted that it intends to review this utility return[120]:

> "As part of the last Biennial Review, the Commission determined that the margin should no longer be calculated on a per kWh volumetric basis and should, instead, be an annual fixed charge.[15] Given this historical experience and perspective, the Commission is interested in information supporting a conclusion that Pepco's margin is reasonable or, in the alternative,

[116] See Pepco filing in FC 1017, February 12, 2018, Attachment D, Page 1 of 10 Columns F & I Pre-Tax CWC and Taxes on CWC, and see Page 1A for Forecasted kWh
[117] Ibid Attachment D, Page 9 of 10 vs. Page 10 of 10
[118] See Pepco filing August 1, 2018 in FC 1017.
[119] DCPSC Order 18829, paragraphs 143 through 148.
[120] DCPSC Order 19431 – August 9, 2018 p. 3

what evidence supports a conclusion that the margin should be modified.16 Therefore, the Commission as part of the 2018 Biennial Review, invites comments on the following issue:

- What is the appropriate return for Pepco to earn as SOS Administrator? What should be the relationship between this return and cash working capital?17

15 Order No. 18829, ¶ ¶ 1, 143, and 393.
16 The Maryland Public Service Commission recently initiated an investigation regarding what an appropriate level of margin was for Baltimore Gas and Electric Company to receive as SOS administrator. *See* www.psc.state.md.us/search-results/?keyword=9221&x.x=17&x.y=14&search=all&search=case.
17 In preparing comments on this issue, interested persons are encouraged to examine the Commission initial consideration of this issue in 2004. *See generally Formal Case No. 1017*, Order No. 13268, ¶¶ 25-71, rel. August 19, 2004"

It is not clear how a change in the SOS procurement model might change the Commission's evaluation of the return required to compensate Pepco for risks associated with serving as the SOS Administrator. Language from the Commission's 2004 Order 13268, initially authorizing a margin for Pepco, states:

> "…that it is appropriate to include a margin in the Administrative Charge to fully compensate PEPCO for the risk, including lost opportunity costs, it is incurring as the SOS provider. "[121]

The levels of margin originally approved by the DCPSC, and which effectively form the bases for the current margins levels, appear to be based on an original proposal by PEPCO that was consistent with margins approved in Maryland.[122]

<u>Adder</u>

The final component of the Administrative Charge is the Adder, which is the difference between all of the cost elements identified above and an overall level of authorized Administrative Charge. As stated in the Commission's 2004 order,

"… the adder places SOS on par on a rate basis with competitive electricity supply in a way that meets the 1999 Act's mandates that SOS not impede the development of a competitive retail market and allows this service to retain its backstop nature."

As noted above, for the SOS rating period of June 1, 2018 through May 31, 2019, the Administrative Charges for each class of SOS service are as follows:

- $.0030 per kWh for Residential SOS
- $.0045 per kWh for Small Commercial SOS
- $.0050 per kWh for Large Commercial SOS

[121] DCPSC Order 13268, paragraph 65
[122] Ibid, paragraph 70

The Adder acts as a “plug”, and might be changed in the future to adapt to any underlying changes in other identified SOS costs elements. This could moderate or eliminate any effect on actual SOS costs that would result from changes in those identifiable costs.

Note that the Commission has placed the issue “Should the adder be eliminated? If so, why; if not, why not” on the list of designated issues for the biennial SOS review.[123]

[123] DCPSC Order 19431 pp. 3 - 4

APPENDIX 8

Typical PPA Terms

Table A8.1 lists a number of the terms and conditions typical of PPA contracts with brief descriptions. Many of the listed terms relate to product definitions, price and quantity, and reflect terminology typical of renewable energy sales. Other key terms relate to performance assurances, damages, and defaults. These are important given that PPAs with new projects will be signed in advance of their construction and given the long-term of the contracts.

Table A8.1 – Key PPA Contract Provisions

Project Description	The name and location of the project, the name of the RTO where the project is interconnected (e.g. PJM)
Product Definition	Product content: energy, attributes (RECs), and/or capacity. Note that attributes are generally broader than just RECs, and the buyer will own any carbon credits or other types of credits that may become valuable over time associated with the production.
Price	Generally, a fixed price per MWH with or without an annual escalator.
Delivery or Settlement Point	Where the power will be delivered – financially speaking. The project owner may agree to value of the power at a particular pricing "node" on the transmission system, or at a zone or hub average.
Settlement Price	In the PJM and other RTO markets, power can be sold into the wholesale market in the "day ahead" or "real time" markets.
Project Size	Nominal project peak output in MW. Note that for new projects there may be some uncertainty as to final project size due to permitting and final construction details.
Annual Quantity	The annual estimated amount of energy to be delivered. When buying the full output of a project, the actual annual output will vary based on wind and solar availability. Minimum volumes might be included, below which some form of financial settlement to the buyer might be made.
Commercial Operation Date (COD)	For a new project, the expected date of operation. The PPA may contain penalties for delays in operation, and permissible extensions (e.g. force majeure)
Term	Duration of contract in months or years from COD. May include extension provisions.
Payment Terms	Payment for electricity and receipt of the power value are typically on a monthly basis.

Buyer’s Performance Assurance	The project developer will typically provide an upfront amount of financial security to the buyer at the time the PPA is signed, which would be kept by the buyer if the project fails to reach COD. Often the amount of security is reduced over time as the project moves closer to operation. The project owner may have to provide financial assurance under certain circumstances during the life of the contract as well.
Seller’s Performance Assurance	Certain collateral may be required to be provided by the buyer based on the buyer’s financial condition, and market prices.
Delay and Other Damages	The buyer may be eligible for a variety of damages in case of unexcused delay in the project coming on line or unexcused interruptions in output during the term.
Defaults	Should there be a default by either party (e.g. failure to pay, unexcused or uncured failure to deliver power, bankruptcy), financial settlement provisions are specified.

APPENDIX 9

Tier 1 REC Market

Table A9.1 summarizes data from recent DCPSC reports on RPS compliance from the past several years[124]. The data show that wind RECs have become the predominant source of Tier 1 compliance, with out-of-state solar projects beginning to contribute in the past few years. The data also show no directionality in wind REC prices since 2011.

Table A9.1 also summarizes data from reports prepared by the Maryland Public Service Commission.[125] The data show a significant contribution of wind RECs to Tier 1 requirements since 2012, and a steep ramp up in Tier 1 REC prices in that state through 2015. CRI believes that MD Tier 1 REC prices have declined, more recently, to well below $10. Note that the Maryland reports do not provide a unit cost breakdown between REC sources. The higher Maryland Tier 1 REC prices compared to D.C. appear to be driven by Maryland's somewhat more restrictive geographic sourcing requirements.

On a going forward basis, the District's Department of Energy & Environment has been examining the future supply demand balance for Tier 1 RECs.[126] Preliminary findings are that the supply of Tier 1 RECs within the PJM states should keep pace with, and be slightly in excess of, the cumulative RPS requirements of those states over the next ten years, given current regional RPS requirements and certain sourcing assumptions. This would imply stability in REC prices.

Table A9.1 – Selected D.C. and Maryland Tier 1 REC Data

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
DC RPS Reports										
% of Tier 1 RECs from Wind	0.3%	0.7%	2.5%	5.9%	29.2%	7.4%	N/A	19.8%	33.5%	63.9%
Unit Price of Wind RECs	$1.24	$0.47	N/A	$2.67	$2.37	$2.38	$2.55	$2.15	$1.87	$2.89
% of Tier 1 RECs from Non-Carveout Solar								1.6%	3.5%	5.6%
Unit Price of Non-Carve-out Solar RECs								$1.00	$2.18	$3.03
MD RPS Reports										
% of Tier 1 RECs from Wind	0.5%	1.4%	0.9%	14.2%	28.6%	38.5%	27.4%	23.0%	32.4%	
Unit Price of All Tier 1 Non-Solar-Carve-out RECs	$0.94	$0.96	$0.99	$2.02	$3.19	$6.70	$11.64	$13.87	$12.53	

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[124] Data compiled by CRI from "Public Service Commission of the District of Columbia Report on the Renewable Energy Portfolio Standard for Compliance Year 2017, May 1, 2018" and similar documents from prior years.
[125] Data compiled by CRI from "PUBLIC SERVICE COMMISSION OF MARYLAND RENEWABLE ENERGY PORTFOLIO STANDARD REPORT With Data for Calendar Year 2016" and similar documents from prior years.
[126] "A Preliminary Analysis of the Economic Impact of the RPS Provision in the Clean Energy DC Omnibus Bill in the Next 5 to 10 Years", D.C. Department of Energy & Environment, September 2019

An August 29th draft report on the future supply/demand balance of PJM Tier 1 RECs, prepared for the Maryland Power Plant Research Project (PPRP),[127] projects a modest shortfall in REC supply in the medium term, with a ramp up in the contribution of large-scale solar projects bringing the market into balance by 2030.

Based on the recent regional history and based on projections of approximate supply/demand balance in the PJM region in the coming years, there are no indications that Tier 1 REC prices will be under upward pressure. This study has not projected Tier 1 REC price increases in its SOS cost model, therefore, nor has this study attributed further SOS price stability benefits to the fact that RECs are bundled into the proposed PPA contracts.

If RPS goals are increased substantially by states across the PJM region, and/or if new states introduce RPS programs, Tier 1 REC demand could grow to an extent that puts upward pressure on REC prices.

[127] Final Draft 2017 Inventory of Renewable Energy Generators KEVIN PORTER AND LAURA MILLER, EXETER ASSOCIATES, INC. PRESENTATION TO MARYLAND RPS WORK GROUP, DAVIDSON, MARYLAND, AUGUST 29, 2018. http://dnr.maryland.gov/pprp/Documents/2017-Inventory-Report-Presentation-RPSWorkGroup.pdf

APPENDIX 10

Frequently Asked Questions

1. *If 70% to 90% of total annual SOS requirements are purchased through long-term PPAs, will battery storage services need to be procured as well?*

   No. The PJM hourly spot market provides energy to cover any gaps between SOS hourly customer requirements and PPA supplies. End users do not need their own contracts for "balancing" services. Today, hour-by-hour tracking of end user electricity requirements is accommodated by varying the output of flexible generating units, primarily natural gas power plants. Batteries will likely play a larger role in the grid's balancing capabilities in the future, as fossil fuel generators are phased out and as renewables account for a greater share of total electricity generation. Whatever the source of balancing capabilities, however, the PJM spot market is structured to provide it.

2. *Why doesn't the study include a 100% renewable energy scenario?*

   It is possible to sign PPAs to cover 100% of SOS annual requirements. A few considerations, however, should ultimately inform the percentage of renewable energy purchased under long-term PPAs:
   - PPA volumes should reflect long-term projections for customer energy use. If efficiency goals call for energy use reductions, for example, then long-term PPAs should be sized to expected requirements in later years. PPA volumes that are 70% of requirements today could be a higher percentage of requirements 10 to 15 years from now.
   - Some cushion for migration away from SOS should be considered. While SOS volumes have been steady in recent years, it may be advisable not to commit to 100% load retention.
   - Detailed price stability analysis might speak for less than 100% PPA supply. When the hourly and seasonal production profiles of a portfolio of wind and solar projects is analyzed against hourly and seasonal SOS requirements, detailed analysis might reveal that 100% PPA purchases lead to significant excess supplies in certain time periods that could add to price variability.

3. *Will the PPA approach for SOS recommended in the study prohibit the use of time varying rates for SOS generation supply?*

   No. Moving to the PPA approach will not preclude offering time varying retail rates to SOS customers. In fact, the PPA approach may be better suited to offering such prices than the current FRS strategy. FRS wholesale supply contracts are not time based, so time-based retail rates would create mismatches between SOS revenues and FRS costs. The PPA approach includes spot market purchases which have hourly varying prices. This supply is better aligned with time-based retail rates.

4. *Will SOS prices to customers vary month to month? If so how much will they vary?*

   Retail prices to customers can be held fixed for periods of time under the PPA model. SOS supply costs will vary each month, due to the changing differences between renewable power production and SOS customer requirements as well as to market price fluctuations. Monthly differences between supply costs and retail revenues can be accumulated in "tracking accounts" for periods of time, and then recovered through "true-up charges" included in retail rates in future periods. Regional municipal governments and buying groups use this type of price setting for their member accounts to provide price stability.

5. *If SOS includes spot market purchases, won't that make the final price of energy more expensive?*

   Spot market prices are not inherently high, and their inclusion in the PPA procurement process will not necessarily lead to higher costs. Since spot market prices vary from hour to hour, however, their effect on SOS costs depends on the hourly differences between renewable energy production and SOS customer requirements and spot prices during those hours. The fact that solar power projects reach peak production in mid-day and wind power projects offer high levels of production on cold winter nights, both times of potentially high spot power prices, can help mitigate exposure to high spot prices.

6. *What will happen to SOS costs in an extreme weather event like Polar Vortex of 2014?*

   Certainly, extreme weather events can cause high electricity supply costs during those brief time windows. As noted in FAQ #4 above, higher costs in a particular month can be carried in a tracking account and spread out over a future period through a true-up charge. Tables 4.2 and 4.3 in Section 4 of this report show that while energy costs under a PPA model would rise in a weather scenario like 2014, the increased cost for the full year would not be larger than some yearly increases experienced in the conventional power market using the current FRS strategy.

7. *If conventional power prices dropped significantly and SOS appeared expensive, could SOS customers switch to competitive suppliers to get lower rates? If so, what will happen to the cost of SOS under the PPA approach as more people switched?*

   SOS customers do have the option to switch to competitive supply in the District's competitive retail electricity market. As noted in FAQ #2, potential customer migration is one factor that supports locking in less than 100% of current needs under long-term PPAs.

   As seen in Figures 4.1 and 4.2 in Section 4 of this report, there was some migration away from SOS during the 2009 to 2012 period. This was a time when market prices for power had dropped significantly, while "smoothed" SOS prices were responding slowly to that decline. The migration was, however, limited. It is also worthwhile to note that PJM conventional power prices are currently at a low point, and further price declines for energy of a significant magnitude are not mathematically possible.

CERTIFICATE OF SERVICE

I hereby certify on behalf of the District of Columbia Government that a copy of Comments of the Department of Energy and Environment on Behalf of the District of Columbia Government was electronically delivered on this 9th day of November 2018, on the following parties:

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