Alternatives to Building a New Mt. Vernon Substation in Washington, DC

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Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2 Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

AUTHORS

Asa S. Hopkins, PhD
Kenji Takahashi

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1. INTRODUCTION

Pepco Holdings Inc. (Pepco) is proposing to build a new substation in the Mt. Vernon area, with an online date of June 1, 2022 (to be ready for the anticipated summer peak in 2022). This substation would serve a portion of the load currently served by two substations: Northeast Substation #212 and 10th Street Substation #52. This new substation would cost over $150 million, and Synapse Energy Economics (Synapse) has analyzed the area to determine if reliability could be maintained at lower cost.

This report begins with a summary of the electrical background of the loads and electric infrastructure in the Mt. Vernon area, along with identification of the specific buildings that are the most likely targets for distributed energy resource implementation to defer or avoid the proposed new substation. Section 3 turns to Pepco's load forecast and examines its methodology and implications for the loads served by Northeast Substation #212. Section 4 examines the economics of substation deferral, calculating that each year of deferral would save ratepayers more than $8 million. Distributed energy resources (DERs), such as energy efficiency, distributed generation, demand response, and battery storage can lead to that deferral. Section 5 describes the potential of each of these DERs in the targeted neighborhood and the associated costs. Section 6 describes three DER portfolios that can cost-effectively defer the substation for one year, two years, or indefinitely, and then suggests a path forward for program implementation. The report concludes with a brief discussion of the programmatic features that may be required to achieve the high levels of program participation necessary to defer the substation.

The District of Columbia Department of Energy and Environment (DOEE) previously contracted with Greenlink to analyze the potential for energy efficiency and solar PV to reduce peak loads in the Mt. Vernon Square area. Greenlink's analysis did not target the specific circuits that are driving Pepco's claimed need for a new substation, but its analysis did overlap with ours. We have used Greenlink's building-by-building energy modeling to act as a check on our work and inform our thinking regarding the potential for efficiency and solar PV. Greenlink developed a database of all the buildings within a one-square-mile circle of the Convention Center, including both existing buildings and announced new buildings. Our identification of the particular buildings which can make the difference for deferring or avoiding the new substation draws upon this work.

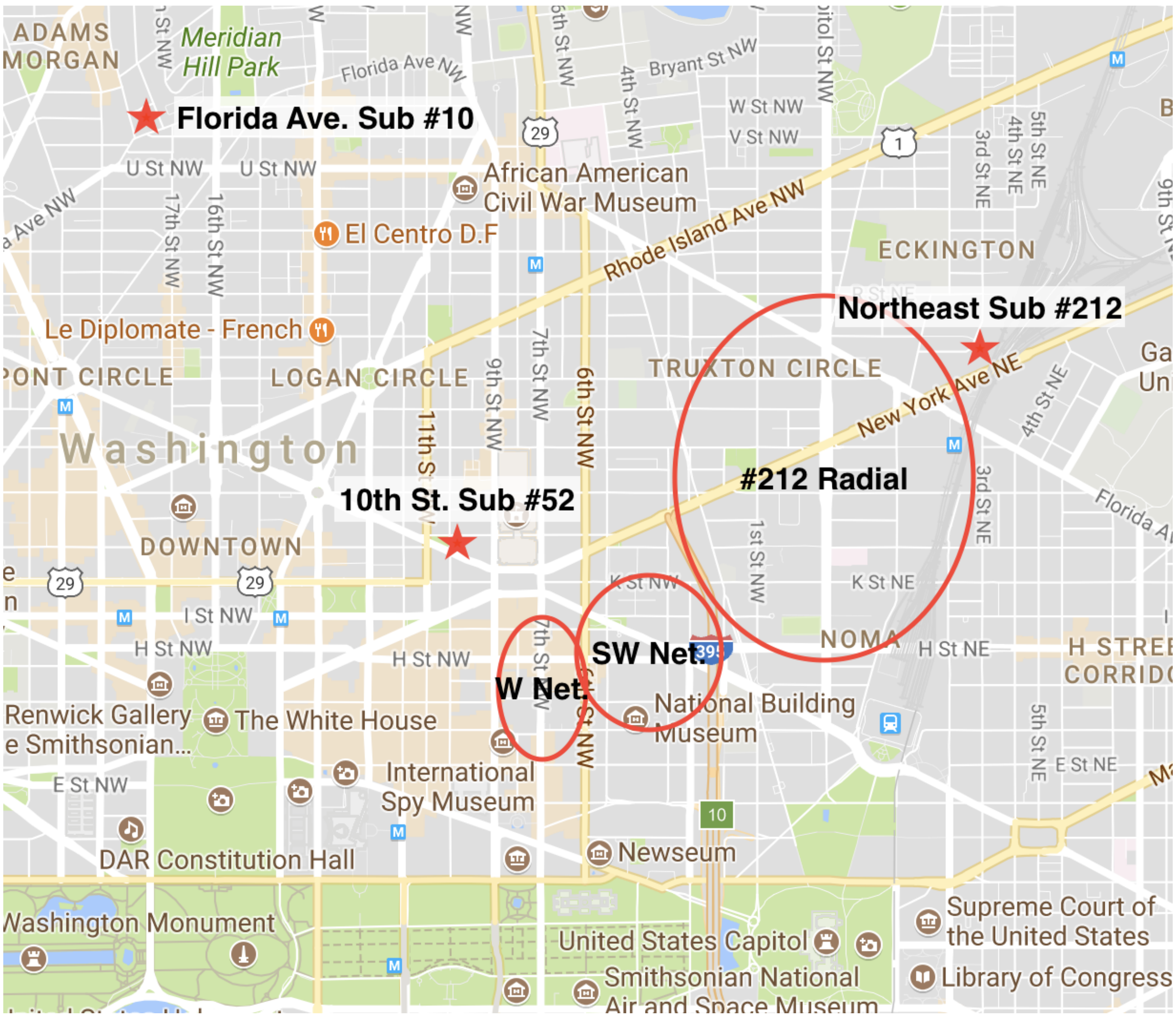
2. BACKGROUND

2.1. Summary of electrical infrastructure in the Mt. Vernon Square Area

Electric loads between Union Station and 11th Street NW and on the east and west, and Florida Ave. and F Street NW on the north and south, are primarily served by three substations. These substations are:

- Northeast Substation #212 [redacted] with a maximum capacity of 210 megavolt-amperes, or MVA;
- 10th St Substation #52 [redacted] with a maximum capacity of 204 MVA; and
- Florida Substation #10 [redacted] with a maximum capacity of 210 MVA.

Figure 1: Map of downtown Washington, DC, showing the approximate location of substations and portions of the electric grid discussed in this report



Source: Pepco hosting capacity map, Google Maps.

Together these three substations served a peak load of 402.7 MVA in 2016, which has grown from 303.8 MVA in 2008. Pepco has adapted to growing loads in part by shifting loads to and among these substations. Northeast Sub #212 was built in 2007, and it has served as the recipient for net shifts of load from the other subs. Some of the growth in load served by these three substations reflects transfers of load from others (such as a transfer of 33 MVA to Sub #10 from 12th and Irving Sub. #133 in 2014). Substation #7 [redacted] also serves a small network on the east side of North Capital Street. New Jersey Ave. Substation #161 [redacted] serves an area just south of the rapidly growing NoMa area, as well as the H Street Corridor.

Substations #10, #52, and #212 generally cover the same territory as they have since 2008 (except for one transfer in to #10 in 2014) so we can look at the set of three as an indicator of the growing loads in the general area of Mt. Vernon, Shaw, and NoMa.

The three substations of primary interest for this work each serve both radial and network systems. Of particular interest for this analysis is the Southwest Low Voltage AC Network Group ("SW Network Group") served by Sub #212. The SW Network Group serves load located between Gallery Place and the Verizon Center on the west and I-395 on the east, and roughly between F Street and Eye Street NW from south to north. This network is fed by a collection of six feeders from Sub #212. These six feeders have a combined capacity of 50 MVA. Pepco claims that adding additional feeders to serve this network is not possible due to space constraints.

2.2. History of the Mt. Vernon Square Substation proposal

Pepco first proposed constructing a new Mt. Vernon Square Area Substation in 2013. In its 2013 Annual Consolidated Report, Pepco described a need created by the "rapidly developing area in and around the Mt. Vernon Triangle." The substation would have an eventual capacity of 210 MVA, although only 30 MVA would be transferred to it upon completion in 2020. The initial transfer would be 30 MVA from the Southwest LVAC Network Group, although Pepco also proposed that the new substation would provide relief to Sub #52, which has consistently had a peak loading of 90 percent or greater of its capacity since 2005. Pepco projected a total capital investment of $131.2 million. Pepco also projected that the 90/10 load on the SW Network Group would rise from 28 MVA in 2012 to 50.9 MVA in 2019 and then to 57.5 MCVA in 2022. Given the 51 MVA limit,[1] the new substation would be required in 2020. The increase in SW Network Group load from 28 to 57.5 MVA over a decade is associated with Pepco's claim that "[a]pproximately 140 MVA of long-term growth is identified to come into service in the Mt. Vernon Triangle and NoMa neighborhoods over the next 10 years."

Pepco has returned to the need for the Mt. Vernon Square Area Substation in each subsequent Annual Consolidated Report (ACR). The planned cost of the proposed substation has changed each year, as shown in Table 1. In 2015 and 2016 Pepco included the cost of the transmission portion of the

[1] Subsequent ACRs report the SW Network Group as having a capacity of 50 MVA, not 51 MVA.

substation in its ACR filing. Transmission-level costs would be recovered from all PJM ratepayers and are regulated by FERC rather than the DC Commission. Because of this, Pepco removed these costs from the most recent ACR. The planned capital cost of the distribution substation has increased at an annual rate of 3.5 percent.

Table 1. Pepco's planned capital investment in the Mt. Vernon Square Area Substation in each of the last five Annual Consolidated Reports

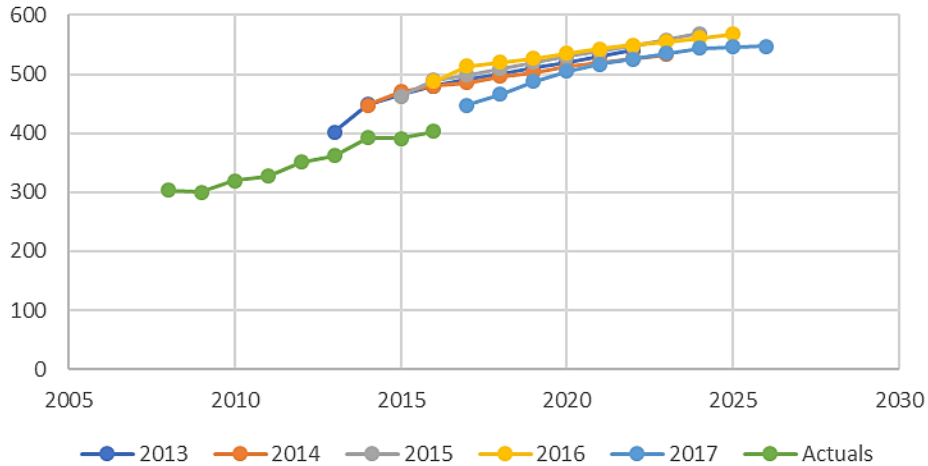
Year of ACR	Planned Capital Investment
2013	$131,214,000
2014	$141,843,000
2015	$298,398,000
2016	$317,313,000
2017	$150,479,000

In each of the five ACRs published between 2013 and 2017, Pepco has used exactly the same words to describe the justification for the Mt. Vernon Square Area Sub: "Approximately 140 MVA of long-term growth is identified to come into service in the Mt. Vernon Triangle and NoMa neighborhoods over the next 10 years." In the 2103 ACR, Pepco projected the combined 90/10 peak load[2] of Subs #10, #52, and #212 to rise from 401.7 MVA in 2013 to 540.7 MVA in 2022—an increase of very close to 140 MVA, and a possible source for Pepco's justification (although 33 MVA of that increase is due to transfers of load from another substation).

Figure 2 shows the actual loads for these three subs, along with the five 90/10 forecasts Pepco developed between 2013 and 2017. Each of the forecasts before the 2017 forecast has been increasingly higher than the actual load; we do not yet have the data to judge the 2017 forecast.

[2] 90/10 load is the load in weather that occurs no more frequently than once every ten years. Pepco projects loads as 90/10 loads to provide a buffer in case of hotter weather than typical.

Figure 2. Sub #10, #52, and #212 combined peak loads (2008-2016) and forecasts developed in 2013–2017, in MVA



Source: Pepco Annual Consolidated Reports 2013–2017.

Load has not actually risen as fast as Pepco projected: In the most recent ACR, the 2022 peak load projection for these three substations has fallen to 525.3 MVA. The in-service date of the new Mt. Vernon Square Area Substation has also slipped later as the load growth has failed to appear: in 2016 the date shifted to 2021, then in 2017 it shifted to 2022.

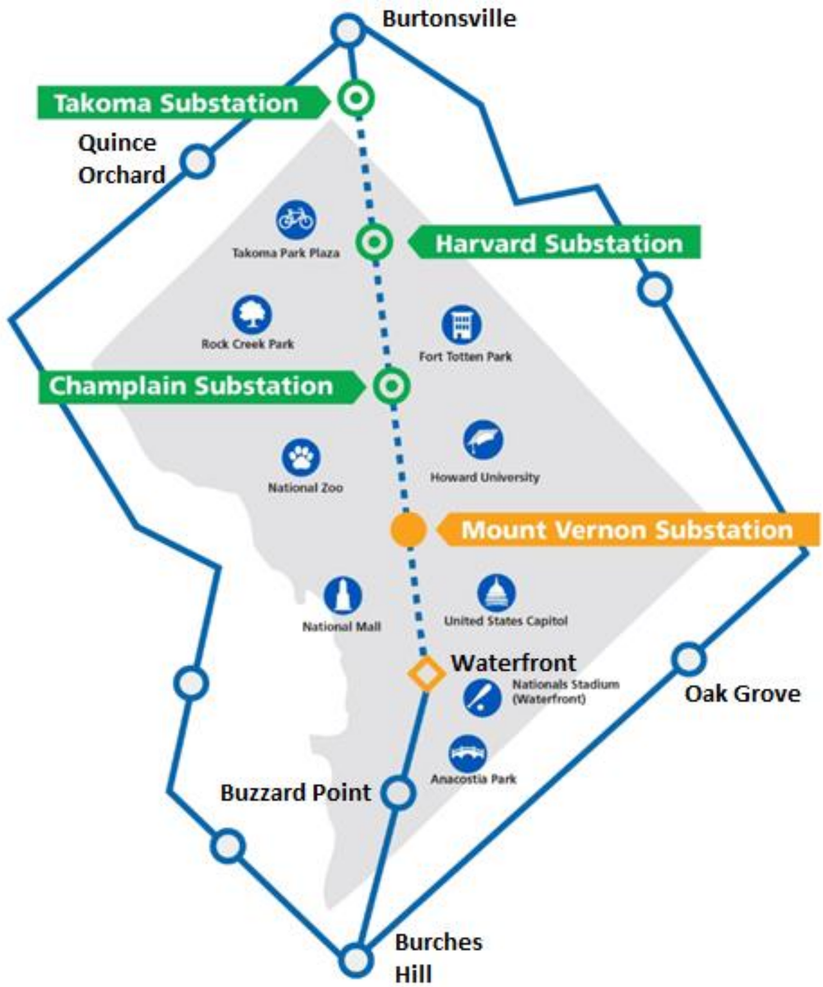
As of the 2017 ACR, the SW Network Group remains the limiting resource whose capacity triggers the need for the new substation. While the 2016 90/10 load on the SW Network Group was 32.2 MVA, Pepco projects the 90/10 load in that area to exceed 50 MVA in 2022 on its way to 63.4 MVA in 2024. Pepco projects the 90/10 load on Sub #212 as a whole to pass that sub's capacity of 210 MVA in 2023 before leveling out at 219 MVA in 2024.

2.3. Mt. Vernon's relationship to Pepco's Capitol Grid transmission project

Pepco has proposed a "Capital Grid" transmission project that would upgrade three substations (Takoma, Harvard, and Champlain), construct the new Mt. Vernon Substation, and connect all of these along a single new underground transmission line to the new Waterfront substation. This would have the effect of creating a networked, rather than radial, transmission system in the District that would allow power flow from multiple directions and decrease the likelihood of loss of load in the event of a single line failure.

In the PJM stakeholder process, Pepco has described this transmission project as consisting of the transmission sides of the Takoma and Mt. Vernon substations, as well as the Takoma-Mt. Vernon and Mt. Vernon-Waterfront connections, plus upgrades to Waterfront to handle the new feeders. The cost for the transmission portion of this combined project as of the end of 2015 was $337 million.[3] This is in addition to the distribution side costs that are described in the ACR.

Figure 3. Annotated Pepco diagram showing the Capital Grid project: three upgraded substations (green), a new transmission line (dashed line), and the new Mt. Vernon Substation



2.4. Details of existing electrical infrastructure

Northeast Substation #212

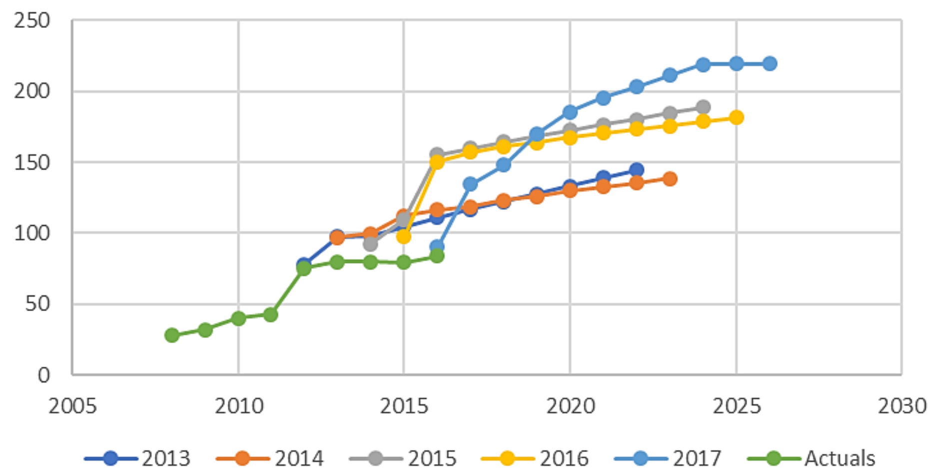
Northeast Sub #212 [redacted] was built in 2007, but not expanded to its full 210 MVA capacity until 2016.

[3] http://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/20151208/20151208-reliability-analysis-update.ashx

Sub #212 serves three load areas: the Southwest Network Group, the West Network Group, and a radial system. Figure 1 shows roughly where these three areas are. Pepco's ACRs provide the historical and forecast loads for the substation as a whole and for the SW Network Group, but not for the West Network Group or the radial system individually. We believe that the current loads (90/10) for the West Network Group are about 40 MVA.

Figure 4 shows the historical actual loads along with Pepco's projected 90/10 loads for Sub #212. The jump between 2016 and 2017 corresponds to a transfer of 40 MVA from Sub #52. We believe that this transferred load is what is now the Sub #212 West Network Group. (This network is adjacent to a network served by Sub #52 and is the closest part of the #212 service area to Sub #52.)

Figure 4. Actual annual peak and projected (90/10) summer peak loads in MVA for the Northeast Substation #212

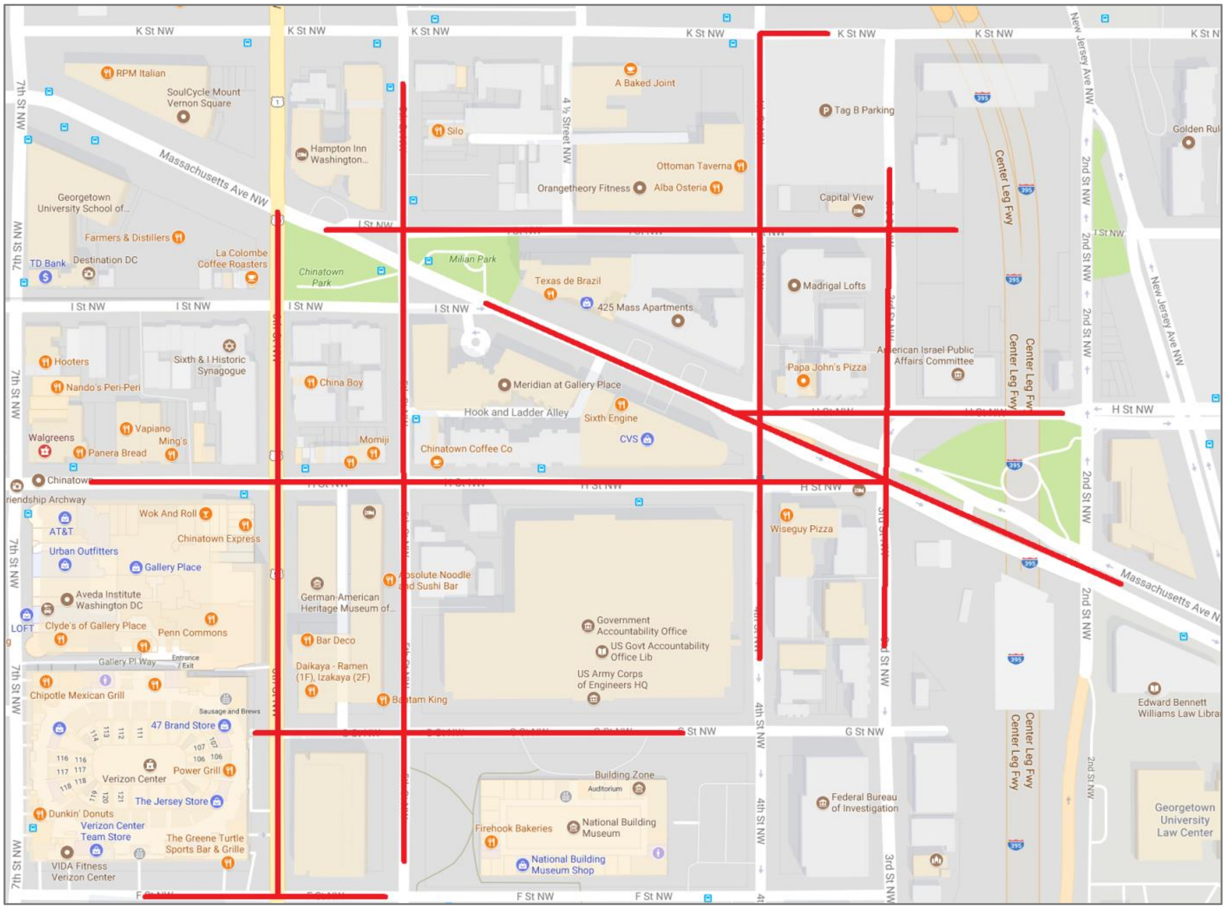


Source: Pepco Annual Consolidated Reports 2013–2017.

Southwest LVAC Network Group

The SW Network Group serves the area to the east and north of the Verizon Center, with a number of office buildings (including the U.S. General Accountability Office) and large apartment buildings. This area bridges between the Penn Quarter and NoMa. Capital Crossing, a 2.2 million sq. ft. five-building development, is under construction now and slated to be completed by 2022 on the eastern edge of this area; it's not clear whether this load would be served by the SW Network Group, radial service from #212, or a different substation altogether. Figure 5 shows the approximate route of the wires in the SW Network Group in red.

Figure 5. Sub #212 SW Network Group



Source: Pepco hosting capacity map, Google Maps.

From Greenlink's dataset, we assembled a list of buildings in the SW Network Group area. We focused on the buildings over 50,000 sq. ft. These large buildings (offices, hotels, and multifamily) are responsible for 95 percent of the peak load, and they are likely the most promising target for policy or programmatic intervention.

Table 2 lists the 16 buildings over 50,000 sq. ft. in Greenlink's dataset and in the SW Network Group. We are aware of two additions to Greenlink's list. The first is an existing building: the 1.94 million sq. ft. General Accountability Office (GAO). The second is a set of proposed buildings: the Capital Crossing complex. Capital Crossing would consist of five buildings located above I-395 to the east of the SW Network Group, with the north end of the complex touching areas now served by that network. Capital Crossing is the only large unbuilt development that we are aware of that might be served by the SW Network Group. Thus, it is our only plausible explanation for Pepco's projection of substantial peak load growth in the next few years.

Table 2. Large buildings in the SW Network Group, with Greenlink's estimate of peak loads

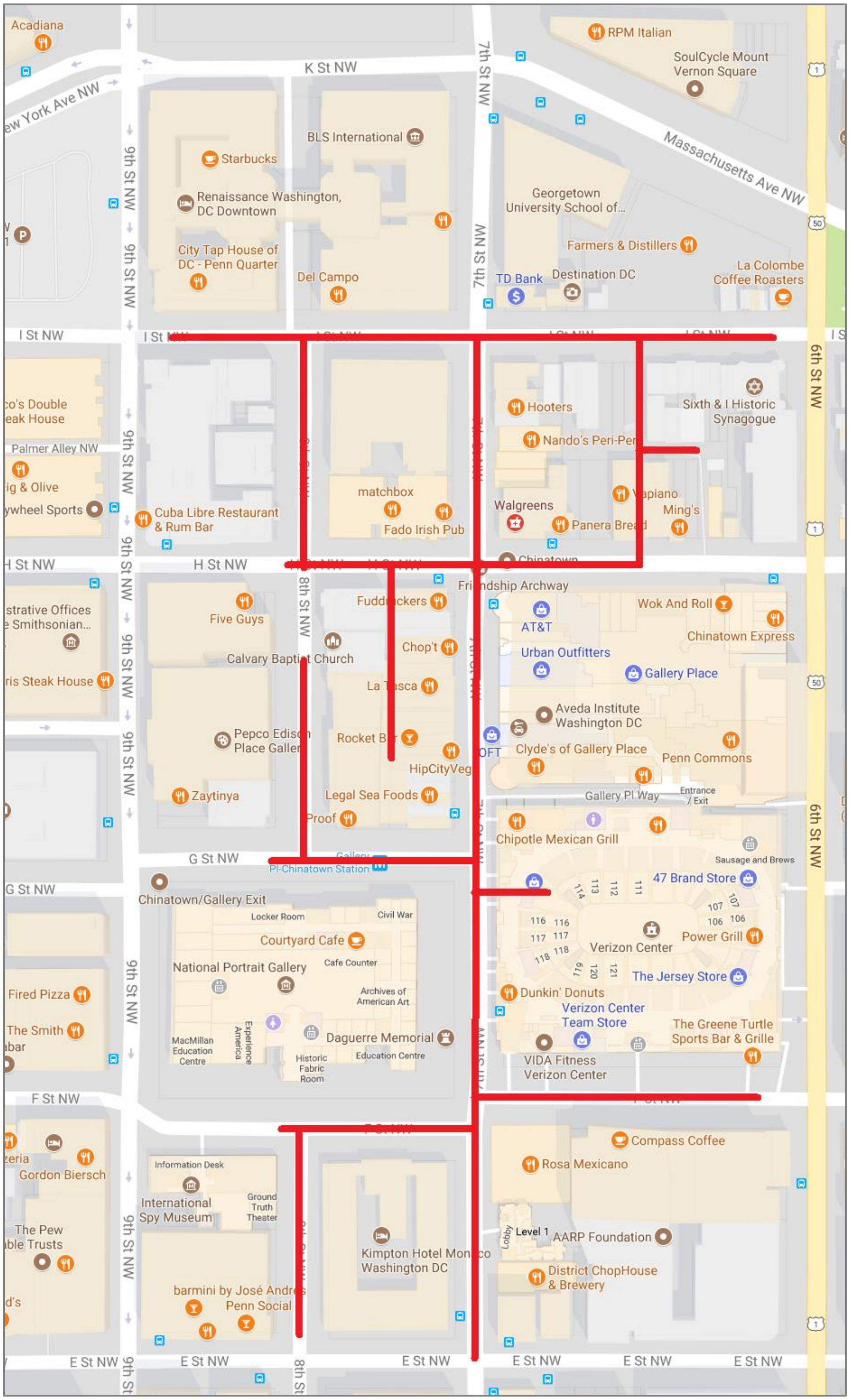
Address	Size (sq. ft.)	Load in peak hour (kW)
441 G St. NW (GAO)	1,935,500	6,342
425 Massachusetts Ave NW	605,405	1,902
Gallery Place	590,688	2,228
600 5th St. NW	423,710	1,388
450 Massachusetts Ave. NW	407,710	1,335
425 I St. NW	399,371	1,309
700 Sixth St. NW	306,459	971
455 Massachusetts Ave. NW	247,330	784
770 5th St. NW	233,968	766
811 4th St. NW	208,767	609
461 H St. NW	197,648	1,325
401 F St. NW	197,094	644
777 6th St. NW	196,997	624
599 Massachusetts Ave. NW	172,236	428
500 H St., NW	120,000	309
251 H St. NW	93,877	298
301 Massachusetts Ave. NW	68,989	201

Note: Based on Greenlink's files "Mt Vernon Residential Baseline Output 09132016" and "Mt Vernon Commercial Baseline Output 09132016." We have added GAO, scaled from the most similar building, the Metro headquarters at 500 6th Street NE, and adjusted two buildings whose modeled consumption values were out of proportion.

West Network Group

According to Pepco's solar hosting capacity maps, the Sub #212 West Network Group serves the area connected to the yellow line in Figure 6. This area includes the Verizon Center, several museums, and a bustling and growing retail and office area on the north side of the Penn Quarter.

Figure 6. Sub #212 West Network Group



Source: Pepco hosting capacity map, Google Maps.

Radial Network

The #212 radial network serves a rapidly growing office and mixed-use cluster in NoMa—north of Union Station on the west side of the railroad tracks—as well as the "Northwest One" area to the west of North Capital Street and south of New York Avenue.[4]

We have not developed a complete set of the buildings served by the radial system because the border lines between the 212 radial distribution circuits and other circuits are not clear in some locations. In addition, the substation may serve some areas outside the area analyzed by Greenlink, although we believe the coverage overlap is generally quite good, especially for larger buildings. However, we can focus attention on the area between Sub #212, the SW Network Group, New York Avenue, and Union Station where most recent, large development has taken place (and is continuing). We identified 35 buildings in this area from Greenlink's analysis as shown in Table 3 below.

[4] We identified the radial network area served by the #212 substation based on Pepco's radial distribution circuit map. The map is available at http://pepco.maps.arcgis.com/apps/webappviewer/index.html?id=75725977c664459f84ef31e305490fd4.

Table 3. Large buildings in the radial feeder portion of the Northeast Substation territory, with Greenlink's estimate of their load at the time of network peak

Address	Size (sq. ft.)	Load in peak hour (kW)
M St. NW & 1st Pl. NW[5]	1,279,845	11,360
130 M St. NE	681,393	3,016
145 N St. NE	623,532	4,319
131 M St. N.E.	436,178	3,123
90 K St. NE	435,400	3,118
1111 N. Capitol St.	416,764	2,887
55 M St. NE	388,890	5,235
64 New York Ave NE	379,149	2,626
62 Pierce St. NE	375,000	5,048
1100 1st St.	360,000	2,494
77 K St. NE	346,026	2,397
1275 1st St. NE	338,645	2,425
1200 N. Capitol St. NW	325,984	2,735
999 N. Capitol St. NE	322,730	2,311
99 New York Ave NE	314,995	2,182
61 Pierce St. NE	307,000	4,133
1200 1st St. NE	303,703	2,104
2 M St. NE	297,720	4,435
1140 N. Capitol St. NW	196,645	2,000
901 New Jersey Ave. NW	174,591	1,054
1500 Eckington Pl. NE	174,150	1,247
N. Capitol St. NE and M St. NE	147,135	1,981
1st St. NE & N St. NE	147,135	1,981
51 N St. NE	142,000	1,017
1133 North Capitol St. NE	119,015	405
1050 New Jersey Ave. NW	112,378	1,104
1006 N. Capitol St. NE	110,856	1,492
901 1st St. NW	110,681	388
1125 New Jersey Ave NW	104,200	490
44 P St. NW	96,122	988
1011 N. Capitol St. NE	81,333	1,309
55 M St. NW	63,444	673

[5] This is the large new development in Northwest One proposed by the Sorsum Corda Cooperative. (See https://www.bizjournals.com/washington/breaking_ground/2015/08/the-end-is-near-for-sursum-corda-as-co-op-owner.html).

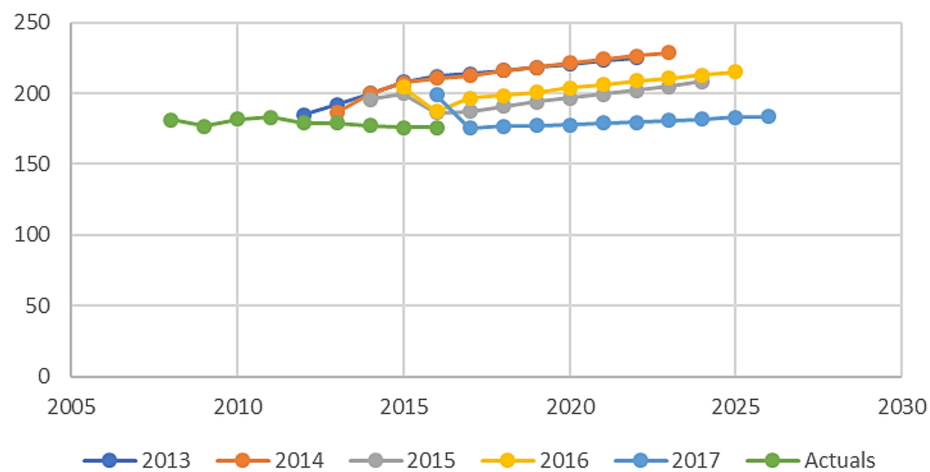
44 Porter St. NE	60,673	169
1300 1st St. NE	54,874	392
1201 1st St. NE	50,000	862

10th St Substation #52

The 10th St Substation #52 [redacted] has a maximum capacity of 210 MVA, and it has had peaks within 15 percent of that level every year since 2005. The highest recorded demand is 183.2 MVA in 2011. Pepco has maintained this level in spite of growing overall load by transferring load away from the substation to others. In particular, Pepco transferred about 40 MVA of peak load to the Northeast Substation #212 in 2016. The 10th St Sub serves two underground networks (West and East) [redacted] adjacent to Sub #212's West Group. The 10th St Sub also serves, by a radial network, much of the area to the north and east of the substation, as far as 1st or 2nd Street NW on the east and past Rhode Island Avenue.

Figure 7 shows the actual loads and the history of Pepco's projected loads for this substation, in MVA.

Figure 7. Actual load and Pepco's history of projected loads for the 10th St Substation #52, in MVA

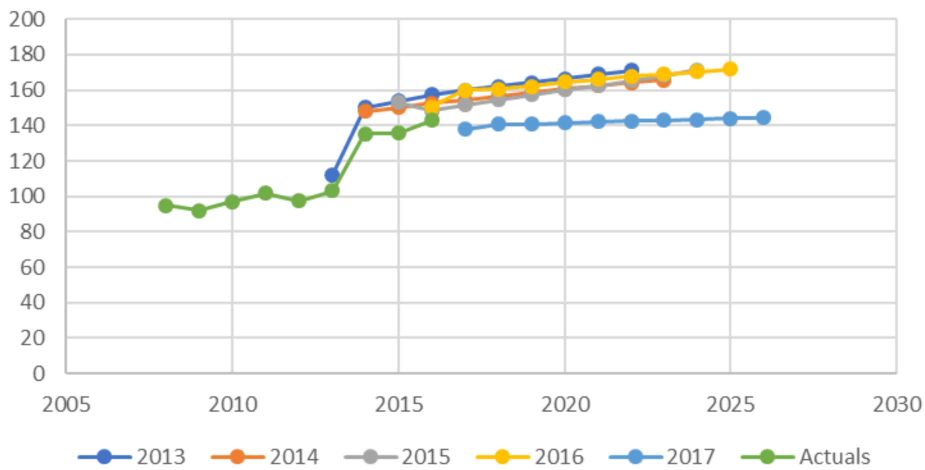


Source: Pepco Annual Consolidated Reports 2013–2017.

Florida Ave Substation #10

The Florida Ave Substation #10 [redacted] has a maximum capacity of 210 MVA, having been upgraded from 144 MVA in 2014. That upgrade was associated with a transfer of approximately 33 MVA from the 12th and Irving Substation #133. The Florida Ave Sub serves a network group that runs from Florida Avenue to the Convention Center centered on 7th Street NW. This network also extends to the east around New York Avenue, where it runs along the north side of the Northeast Sub's SW Network Group. Pepco claims that transferring load to this substation from Subs #212 and #52 to avoid or defer the new Mt. Vernon Square Substation is not practical due to the long length of the feeders that would be necessary to serve loads that would be quite far from the Florida Ave Sub. The load on this substation has been slowly growing, driven by growth in the Shaw and Convention Center areas. Figure 8 shows the historical load on this substation, including the 2014 transfer of load from Sub #133, along with Pepco's history of projections for load.

Figure 8. Actual load and Pepco's history of projected loads for the Florida Ave Substation #10, in MVA



Source: Pepco Annual Consolidated Reports 2013–2017.

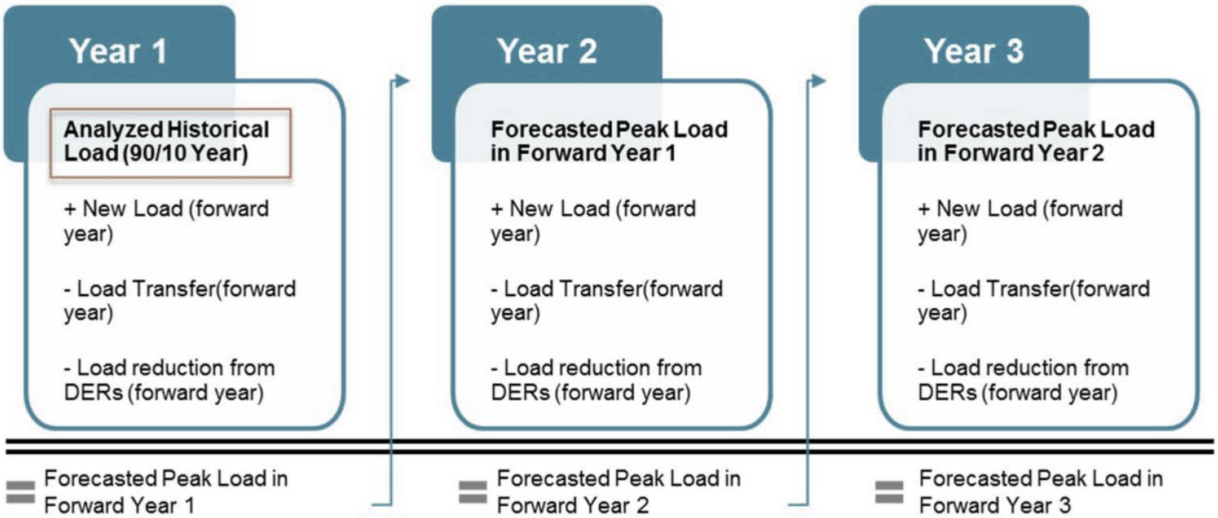
3. Pepco's Load Forecast

3.1. Methodology

Pepco describes its long-range peak load forecasting methodology in a September 2016 report: "Distributed Energy Resources and the Distribution System Planning Process." This report is a component of a process agreed to as part of the Exelon-PHI merger to increase transparency around DERs and show how DERs are incorporated into system planning processes.

Pepco's peak load forecasting process is composed of a short-term forecast (Years 1–3) and a long-range forecast (Years 4–10). Pepco develops a separate forecast for each feeder, substation transformer, and substation on its system to "ensure that both individual system components are sized appropriately, and that the system as a whole will perform as it should." The short-term forecast is built year by year from the historical 90/10 load plus and minus identified adjustments for load growth, load transfer, and the impacts of DERs. Figure 9 illustrates this process for the near term.

Figure 9. Pepco's illustration of its near-term peak forecasting process



Pepco develops the long-range forecast by (1) trending the short-term forecast, (2) adjusting for known events such as major new building developments in the 4–10 year window, and (3) calibrating the cumulative system peaks from all of the components so that they add up to the trend forecast by PJM.

3.2. 90/10 versus typical weather

In its 2015 ACR, Pepco compared the sum of the 90/10 forecast loads it had developed for the District's substations with the observed loads in each of the preceding five years. On average across those five years, the predicted loads were 10 percent higher than the actual loads. While this is not the 10 (or more) year sample that we would like to see to compare typical with 90/10 weather, it provides a general guideline to suggest that 90/10 loads should be expected to be about 10 percent above 50/50 or typical weather loads.

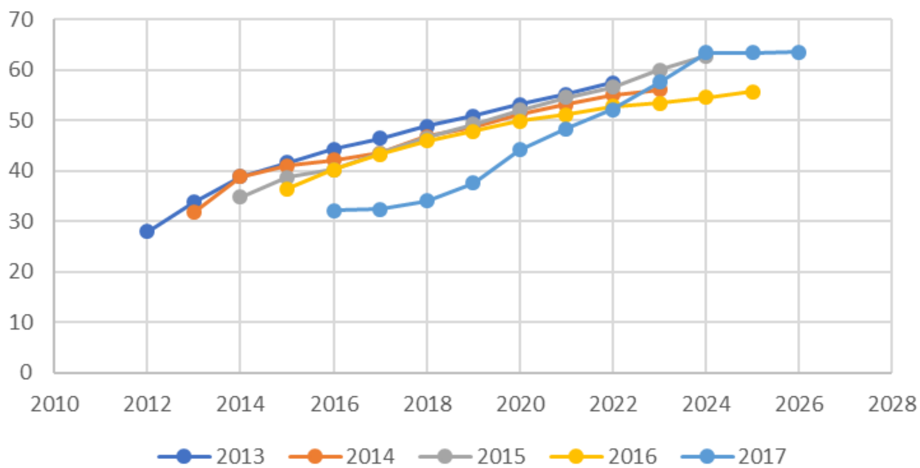
3.3. Power factor

Pepco projects the peak loads for its substations in terms of MVA. Meanwhile, most energy analysis, including Greenlink's modeling, works in terms of megawatts, or MW. Watts measure real power, while volt-amps include reactive power. Motors, for example, cause the waveform on the alternating current to shift, creating reactive power and lowering the power factor. At summer peak, with large numbers of motors running in air conditioners, the power factor of distribution circuits is likely at its lowest value of the year. Pepco reports in its ACRs that it plans for a power factor of 0.98 or better and achieves that level at all but a few substations each year. We have assumed a 2 percent effect in the difference between Pepco's forecast MVA and a building-by-building MW calculation.

3.4. SW Network Group

The SW Network Group has a maximum capacity of 51 MVA, a level which Pepco forecasts it to exceed (under 90/10 weather) in 2022. Figure 10 shows the five forecasts of the load on this network group developed between 2013 (when the Mt. Vernon Substation project was initially identified) and 2017. We do not have the historical actual loads on this network, although the fact that each forecast has been lower than the last indicates that the new loads have not been arriving as quickly as initially thought.

Figure 10. Sub #212 SW Network Group peak load forecasts in MVA, 2013–2017



Source: Pepco Annual Consolidated Reports 2013–2017.

Greenlink collected data on each of the buildings in a one-square-mile circle centered on an area to the north and west of the SW Network Group or NoMa. The circle did include the areas covered by most of the development driving Pepco's proposal. Greenlink includes information regarding some buildings under development or construction at the time of its work; some of these have completed construction, while others will be done later this year or in future years. These new developments are in the radial feeder portion of the Sub #212 service area. (We do not have Pepco's detailed assumptions for future development and associated load.[6]) We added the GAO building to Greenlink's dataset, and assumed that it would have a similar energy-to-square foot relationship as the Metro headquarters at 600 5th Street NW. (We have no other large office buildings of its vintage to use as a model, and Metro is the oldest and a fellow government building.)

[6] The only information on Pepco's assumptions we have is this: "Pepco is actively tracking over 50 active and planned development projects in the Shaw, NoMA, Mt. Vernon Triangle and Capitol Crossing areas which include 9.4 million sq. ft. of new office space, 600,000 sq. ft. of new retail, 6,200 residential units and 1,200 hotel rooms" (Pepco, 2017 Consolidated Report Part 1 – Comprehensive Plan, p. 13).

After adding GAO in, Greenlink's peak hour load for the full SW Network Group is 23.26 MW. The peak is modeled as the 3–4pm hour on a July afternoon under typical weather. The 17 large buildings (over 50,000 sq. ft.) have a load of 21.3 MW. This is more than 90 percent of the total and we have therefore focused further DER analysis on addressing these large buildings.

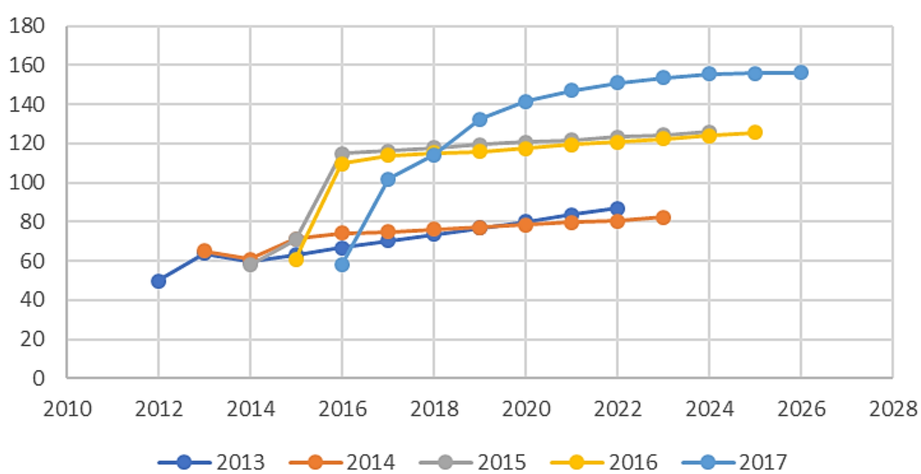
Greenlink used "typical" weather whereas Pepco uses 90/10 weather (the 90th percentile of heat and humidity). Pepco predicts a load of about 32.4 MVA for 2017 for this area under 90/10 weather. There is a difference of 9.1 (or 28 percent) between the 23.3 MW from Greenlink and 32.4 MVA from Pepco. This difference could be more than half accounted for by some combination of line losses (a few percent), power factor (2 percent), and the difference between typical and 90/10 weather (10 percent). Further difference is unexplained until we better understand the data and assumptions underlying Pepco's forecast.

If Capitol Crossing uses the same amount of electricity on peak (per square foot) as a typical recent office building in this area, it would contribute another 7 MW. We have no reasonable theories to explain the rest of the more than 20 MVA of growth that Pepco projects in this area by 2024.

3.5. Remainder of Northeast Substation 212

Figure 11 shows the 90/10 forecasts for #212 without the SW Network Group (so it includes both the radial system and, starting in 2016, the West Network). The growth between 2017 and 2022 in the 2017 forecast was not seen in the earlier forecasts, and it may reflect updated information regarding developments in NoMa. It may also reflect shifts in which substation will carry growth: Subs #10 and #52 have reductions in their long-term growth rates in the 2017 ACR.

Figure 11. Sub #212 peak load forecasts in MVA for the combination of the radial feeders and West Network Group, 2013–2017



Source: Pepco Annual Consolidated Reports 2013–2017.

Using Greenlink's analysis, we have identified 35 planned or existing buildings that are projected to dominate the load in the radial portion of the Substation #212 area. These 35 buildings have a peak load in Greenlink's modeling of 83.5 MW. The southern end of the radial area is hard to distinguish based on Pepco's map—a few more buildings may be in or out of the area served by Sub #212. In addition, we are presuming that the small network in this area served by Substation #7 is small enough to be neglected. To the extent this load is significant, it would increase the gap between Greenlink's modeled peaks and Pepco's projections. If we have a chance to gather further information, data on the load in this area—by feeder and network—would be quite beneficial.

A significant fraction of the West Network Group falls outside the area modeled by Greenlink in its earlier analysis for the DOEE. As a result, we have no independent assessment of the expected load in this area. If this area is the load that was transferred from Sub #52, as we suspect, then the peak load of this area is about 40 MVA.

Pepco's modeling for the non-SW-LVAC-Group portion of the substation gets to 150 MVA by 2022, and after removing 40 MVA for the West Network Group, that would leave 110 MVA for the radial system as a whole, in 90/10 weather. The difference from the load estimate in Greenlink's modeling of 83.5 MW is about 27 MW or MVA (or about 32 percent of the modeled load). Similar to the SW Network Group, a 25 percent adjustment could be mostly accounted for by a combination of losses, power factor, and the weather adjustment, but a gap remains. There will also be a few MVA of load from the smaller buildings served by the radial network and not included in our Greenlink subset.

3.6. Pepco's forecast for the SW Network Group is hard to believe

For each year between 2012 and 2016, Pepco's ACRs provide the load on the SW Network Group that would have occurred if that year had been an extreme weather year (the peak under 90/10 conditions). These peaks have stayed between 28 and 36.4 MVA—they rose slowly from 28 in 2012 to 36.4 in 2015 before falling back to 32.2 in 2016. This slow change—an average increase of only slightly over 1 MVA per year—reflects the relative stasis of the building stock in this small area of the District. No major buildings have been constructed in this area since 2009, although a few building permits have been granted, presumably for renovations or other work.

According to Greenlink's analysis,[7] the buildings we identified as falling in this area have a total of 6.83 million sq. ft. Using the 2016 90/10 peak, this implies an aggregate peak load of 4.71 Volt-amps per square foot. Greenlink's building modeling calculates 4.0 W/sq. ft. using typical weather. A combination of the weather difference, losses, and accounting for power factor could be sufficient to nearly bridge the 18 percent gap between Pepco's load per square foot and Greenlink's.

If we take the 4.71 VA/sq. ft. figure from Pepco's peak modeling and combine it with our total building area—and assume that new buildings maintain that level of demand intensity—reaching Pepco's

[7] Plus the 1.935 million sq. ft. GAO building.

forecast of 63.4 MVA in 2024 would require 13.45 million sq. ft. This would represent an increase of 6.61 million sq. ft. (or 97 percent) from the existing buildings. Capitol Crossing, which we are assuming Pepco must be planning to serve from this network, is 2.2 million sq. ft., so Pepco's peak would require at least two more Capitol Crossings-worth of new construction in this area. In other words, one-third or more of the "9.4 million sq. ft. of new office space, 600,000 sq. ft. of new retail, 6,200 residential units and 1,200 hotel rooms" that Pepco claims to have identified across the Shaw, NoMA, Mt. Vernon Triangle, and Capitol Crossing areas would have to be in the SW Network Group area to justify Pepco's forecast.

However, Capitol Crossing is the only "mega" development planned for this area. In addition, Capitol Crossing should be expected to have a lower power intensity (W/sq. ft.) than the existing buildings. It is planned to surpass LEED Platinum status and to include on-site cogeneration.[8]

Could there be other proposed new large buildings which have made their intentions known to Pepco but we have not found? Pepco began forecasting rising loads in this area in 2013, over four years ago. If there were large additional buildings planned for occupancy before 2024 that Pepco knew about at that time, they would have made some sort of public appearance by now. We have identified a commercial source, Recity, that can provide up-to-date commercial and multifamily residential development projections to use in updated analysis once Pepco formally files for the Mt. Vernon Substation.[9]

4. THE ECONOMICS OF DEFERRAL

Deferring a substation produces real value to ratepayers because customers delay paying for the project and its associated return on the utility's capital. If the cost of building the substation rises more slowly than the customers' discount rate, then paying in the future is better than paying in the present. In order to account for all of the detailed utility accounting and ratemaking practice in such a deferral, we have adapted the spreadsheet tool used to evaluate the cost-effectiveness of the Brooklyn-Queens Demand Management non-wires alternative project in New York to the situation of the Mt. Vernon Square Area Substation.[10]

Our adapted tool calculates the present value of the cost of the substation, as run through a utility ratemaking process. That is, it calculates the depreciation of the substation over 50 years and the return on ratebase that Pepco would earn each year, accounting for tax treatment and other standard practices. Then it calculates the present value of this stream of costs. The present value of the project as proposed is $230 million, based on Pepco's estimated capital cost of $150,479,000 in 2017 dollars and

[8] http://www.capitolcrossingdc.com/media/assets/CC_ProjectOverview_Brochure_170717.pdf.

[9] Recity would like to keep its data proprietary, so confidential treatment would be expected in order to access this data and use it in a formal proceeding.

[10] ConEd's cost-benefit analysis and avoided cost spreadsheets can be downloaded from http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=45800.

an in-service date of 2022. The present value is higher than the cost to build because of the cost of capital—Pepco's debt and equity—and income taxes. We use the utility's after-tax weighted average cost of capital as the discount rate.

Pepco's after-tax weighted average cost of capital is 7.46 percent,[11] and assuming the cost of building the substation would increase at 3.48 percent per year in nominal terms,[12] the present value of deferral to each subsequent year is shown in Table 4.

Table 4. Present value of substation deferral for each year past 2022

Year	Present Value of Deferral (millions of $)
2023	$8.51
2024	$16.70
2025	$24.59
2026	$32.18
2027	$39.50

The growing load in the Sub #212 SW Network Group is the driver for the timing of the Mt. Vernon substation proposal. The SW Network Group is projected to pass its capacity by summer of 2022, so that sets the online date for the new substation. Sub #212 as a whole is not projected to pass its capacity until 2023, so if there were no limitations within the #212 configurations, the new sub would be delayed a year. Unfortunately, there is no flexibility to increase the capacity of the SW Network Group at the expense of the rest of #212.

Without the load on the SW Network Group above 50 MVA, there would be no need to build the new Mt. Vernon substation. While Pepco projects the load on the rest of Sub #212's feeders to rise substantially over the next decade, that increase alone would not be sufficient to trigger the need. Pepco projects the total load to grow to 219.5 MVA, exceeding the 210 MVA capacity by 9.5 MVA. Meanwhile Pepco projects the load on the SW Network Group to increase 31.3 MVA and exceed the 50 MVA capacity by 13.5 MVA. If the load on the SW Network Group is kept below 50 MVA, then the total load on the substation is at least 13.5 MVA lower. Then the substation as a whole ends the forecast period at 206 MVA, below its 210 MVA limit.

Taking a closer look at the first three years of substation deferral value, combined with the necessary peak load reductions in the SW Network Group to achieve those savings, results in values per kVA are shown in Table 5.

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[11] Derived from its recent rate case; corresponds to a 9.5% after-tax return on equity.

[12] This is the rate at which the project's estimated cost has risen from 2013 to 2017.

Table 5. Value per kVA of minimal peak reduction for deferral

Defer to	By reducing peak ___ MVA	Value per kVA
2023	2.2	$3,868
2024	7.6	$2,197
2025	13.4	$1,835

If Pepco requires a buffer below the 50 MVA capacity of the SW Network Group, the value per kVA is smaller, but still substantial. If we add a 3 MVA buffer to each of these peak reductions the values fall to the values shown in Table 6.

Table 6. Value per kVA of peak reduction for deferral, with a 3 MVA buffer

Defer to	By reducing peak ___ MVA	Value per kVA
2023	5.2	$1,637
2024	10.6	$1,575
2025	17.4	$1,413

If we assume there is a 5 percent adjustment factor between end-use real power and feeder volt-amps (that is, between MVA and MW) resulting from reduced line losses and the effects of power factor, then the value per real kW of demand reduced would be 5 percent higher than the values just calculated.

4.1. Deferral as the path to avoidance

If reducing the peak load in the SW Network Group by 20 MVA or so would completely remove the need to build the new substation (that is, provide enough of a buffer for Pepco to remove immediate planning for this substation from its capital planning), then the return to ratepayers would be even greater. It would be worth paying more than $11,000 per kVA for 20 MVA of peak reduction to completely avoid the construction of this substation. (Of course, avoiding it for less should be the objective.) Even if complete avoidance required a 30 MVA peak reduction, to keep loads on the SW Network Group close to where they are today, it would still be worth more than $7,500 per kVA. Complete avoidance would also save PJM ratepayers the cost of the transmission substation (more than $160 million[13]) that is associated with this distribution sub.

It is unlikely that complete avoidance of the new substation can be mapped out and planned for from the beginning of non-wires-alternative consideration. Slowing load growth to defer the new substation need by a year buys a year for further DER implementation and forecast refinement. The same is true the next year. Meanwhile, the circumstances on the ground will continue to evolve: New buildings will be proposed, construction plans and schedules will change, planned DERs will perform differently than expected, and new kinds of DERs will become available and cost-effective. This is effectively what is

[13] Estimated based on the difference between the 2016 ACR (which included the transmission portion) and the 2017 ACR (which did not).

happening in the Brooklyn-Queens Demand Management project in New York. Con Edison and the New York regulators have agreed to continue that project even though it is past its original timeline because additional savings from further deferral—and even complete avoidance—may be possible.[14]

5. Non-Wires Alternatives

Meeting the need for reliable service in the SW Network Group in the face of growing load can be met through a "wires" option: Pepco's proposed new substation. However, if the peak can be kept below 50 MVA on this network through "non-wires" alternatives at a lower cost than the substation, reliability will be maintained and ratepayers will be better off. Peak reductions may be acquired from energy efficiency, distributed generation, demand response, or storage.

5.1. Energy efficiency

The vast majority of electricity load in the SW Network Group area belongs to 17 existing, large commercial and multifamily buildings. This group consists of eight office buildings, two hotels, six multifamily buildings, and one large mixed-use building.[15] In addition, the Capital Crossing development currently under construction expects to have a substantial space for offices and retails along with 150 residential units, with a minimum of 50 units designated as affordable housing units.[16] The expected peak load from these 18 buildings is about 26 MW, as discussed above. The remaining peak load (25 MW or more, if Pepco's forecast is correct) is expected to come from unknown new construction buildings in the area.

Among all end-uses, cooling, lighting, refrigeration and computers, TV, and office equipment add the largest load during the local peak hours in Mt. Vernon. A detailed breakdown of peak load by end-use is presented in Table 7 below for large commercial buildings and multifamily buildings. We developed this data based on Greenlink's analysis of building load, along with a detailed end-use breakdown for equipment from the U.S. Energy Information Administration's Commercial Building Energy Survey database.

[14] Microgrid Knowledge, "Con Ed Gets Okay on More Non-Wires Alternatives: 'What Was New Has Become Normal'" https://microgridknowledge.com/non-wires-alternatives-con-ed/. Accessed September 29, 2017.

[15] Identified based on our review of the Greenlink's building analysis.

[16] https://dc.curbed.com/2016/4/6/11376906/capitol-crossing-washington-dc.

Table 7. Share of end-use peak load contribution for commercial and multifamily buildings

End-use	Commercial	Multifamily
Cooling	39%	45%
Lighting	30%	20%
Refrigeration	8%	11%
Computers, TV, office equipment	8%	17%
Ventilation	4%	4%
Water heating	0%	6%
Cooking	1%	3%
Others	10%	13%

Numerous energy efficiency measures are available for these existing and new buildings, particularly for cooling, lighting, refrigeration, and equipment (including computers and electronics). Examples of such measures are provided in Table 8 for cooling, lighting, and refrigeration. As shown in this table, there are numerous retrofit measures (e.g., HVAC tune-ups, insulation, door gasket for freezer, temperature optimization for refrigeration, lighting controls and occupancy censors) which can be implemented any time to reduce peak load. Often these retrofit measures are inexpensive to implement.

Table 8. Examples of energy efficiency measures for commercial buildings in Mt. Vernon

Cooling	Refrigeration	Lighting
Chiller/AC tune up diagnostics	Door gasket for freezer	Central Lighting Control System
Chilled water and cooling tower optimization	Strip curtains	Time clock control
Duct insulation	Suction pipe insulation	Occupancy sensor
Window shade film	Efficient compressor motor	Auto Off Time Switch
Programmable/smart thermostat	Temperature optimization	Efficient lighting systems such as LED
ECM motors for split systems	Vendor Miser	
New efficient HVAC systems	High efficiency refrigerator and freezer	
Central Lighting Control System	ECM evaporator fan motor	
Time clock control		
Occupancy sensor		

Potential peak reduction from energy efficiency

We assessed potential peak load reduction from cost-effective energy efficiency measures in the SW Network Group area. We first reviewed all energy efficiency project data for projects to date implemented by the DC Sustainable Energy Utility (DC SEU) in order to identify the level of savings achieved to date. Second, we reviewed peak savings estimates developed by Greenlink. Lastly, we developed our own peak load savings estimates for the area based on (a) the building data obtained from Greenlink and the DOEE and (b) relevant energy efficiency measure data obtained from a 2015 energy efficiency potential study conducted for the utilities in Pennsylvania. These assessments reveal that there is sufficient peak savings potential from energy efficiency to defer the substation by one year (or longer in concert with other demand-side measures or if potential efficiency savings from new construction are included).

DC SEU peak savings to date

We contacted DC SEU and obtained its program information to assess DC SEU's current program impacts and offerings to the area. Our review of the project data provided reveals that six large buildings participated in the DC SEU's program from 2014 to 2016, and the majority of the savings from those projects came from lighting. Further, we found that just four buildings in this area had implemented energy efficiency measures that had summer impacts, all of which were LED lighting, totaling about 180 kW (Table 9).

Table 9. Energy efficiency measures implemented by DC SEU in SW Group Area with summer peak impacts

Address	Year	Implemented Measures	KW Reduction Summer
777 6th St. NW	2015	LED Parking Garage/Canopy Fixture	1
770 5th St. NW	2015	LED Screw Base Lamp	9
770 5th St. NW	2015	LED 4' Linear Replacement Lamp	8
600 5th St. NW	2016	LED Recessed Lighting Fixture 2X2	145
599 Massachusetts Ave. NW	2016	LED Screw Base Lamp	14
599 Massachusetts Ave. NW	2016	LED 4' Linear Replacement Lamp	4
Total			181

Greenlink's peak savings estimate

Greenlink modeled commercial and multifamily residential buildings as undergoing HVAC retrocommissioning and lighting retrofits.

For the commercial buildings, Greenlink assumed that the largest commercial buildings over 50,000 sq. ft. undergo HVAC retrocommissioning and that 65 percent of all commercial buildings retrofit their lighting to LED over the next five years. Other key assumptions for the commercial buildings are:

- A 20 percent reduction in HVAC demand through retrocommissioning per building, and
- A 50 percent reduction in lighting demand through LED upgrades per building.

For the residential buildings, Greenlink took a whole building approach instead of the measure-specific approach used for commercial buildings. Greenlink assumed that 65 percent of the multifamily buildings undergo new construction or major renovations to meet the latest or more recent building codes over the next five years. Key energy savings assumptions are:

- All new construction multifamily projects in the NoMa area meet the 2016 standard, up from the 2010 standards, for an approximate 20 percent reduction in average energy use intensity;
- Recent multifamily construction (post-2008) upgrades HVAC and lighting to the 2016 standard, from 2010 standards, for a 39 percent reduction in HVAC and lighting demand;
- Middle-aged multifamily buildings (1980–2008) upgrade HVAC and lighting to the 2013 standard, from approximately 2004 standards, for approximately a 45 percent reduction in HVAC and lighting demand; and
- Older multifamily vintage buildings (pre-1980) with upgrades in HVAC and lighting to the 2013 standard, from approximately 1999 standards, for approximately a 57.4 percent reduction in HVAC and lighting demand.

In aggregate across the SW Network Group buildings, Greenlink's analysis results in commercial demand in the peak hour falling by 12 percent and residential peak demand falling by 21 percent. Given the blend of commercial and residential buildings, the net result in the SW Network Group would be a 14 percent peak reduction, or 3.3 MW. This would be sufficient to defer the new Mt. Vernon substation by one year.

Synapse peak savings estimate

Synapse conducted a bottom-up analysis of energy efficiency potential for the SW Network Group buildings to estimate both peak load reduction and the costs to achieve that reduction. This sub-section provides a summary of our savings estimate approach and results. The following sub-section will provide our cost estimates for energy efficiency measures.

Our analysis of peak load savings is primarily based on a 2015 energy efficiency potential study for Pennsylvania.[17] This study took a bottom-up approach to estimate energy efficiency savings for residential, commercial, and industrial sectors for each individual investor-owned utility. The study made its potential measure database available on the Pennsylvania Public Utility Commission website.[18] The database provides annual energy savings, peak load savings, measure life, and incremental costs for each measure by end-use type, measure type (e.g., retrofit, replace on burnout or ROB, new construction), and by utility.

We used the energy efficiency measure data from this study for office buildings, hotels, and multifamily buildings as these are the target buildings in the SW Network area. We also used the data for PECO as

[17] GDS et al. (2015). Energy Efficiency Potential Study for Pennsylvania.

[18] See "Residential Measure Appendix" and "Commercial & Industrial Measure Appendix Tables", available at http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/act_129_statewide_evaluator_swe_.aspx

we consider PECO's customer characteristics are more appropriate to the District than other utilities in Pennsylvania because PECO covers a similar metropolitan area.

We then took the following steps to develop cost-effective, potential measures for the District:

- **Coincident factor**: We adjusted peak load savings estimate downward for peak coincident factors that are currently used by DC SEU.[19] Peak coincident factors are used to reduce peak load savings from the maximum/nominal peak savings level in order to just count peak savings that occur during the "system peak" load hours. This likely results in conservative energy savings estimates for some measures, especially for cooling for our analysis.[20]

- **Target end-use**: We reviewed and screened measures for lighting, cooling, refrigeration, and electronics (including computers, TV, and office equipment) as these end-uses drive the lion's share of peak load contribution as shown in Table 7 above.

- **Cost-effectiveness**: We selected only measures with (a) a benefit cost ratio at or above 1 with the Total Resource Cost (TRC) test; and (b) a cost below $5,000/kW.

The results of our measure screening for existing buildings are presented in Table 10 below. This table shows peak savings separately for retrofit and ROB measures. For our study, we decided to use the average savings and costs between two cases: (a) lower savings of the savings from retrofit and ROB measures; and (b) a sum of the savings from retrofit and ROB measures, assuming that some buildings may implement both retrofit measures and ROB measures (e.g., occupancy sensors and new HVAC), but others may just implement retrofit measures as their HVAC equipment has not yet reached the end of its life. In contrast, Greenlink assumed buildings implement both types of measures for HVAC measures. This difference plus the use of coincidence factors in our analysis as mentioned above resulted in lower cooling savings than Greenlink's 20 percent savings estimate for HVAC. Our lighting savings at the end-use level are also lower than Greenlink's estimate, which is likely due to the use of coincidence factors.

[19] DC Sustainable Utility (2016). Technical Reference Manual (TRM) Measure Savings Algorithms and Cost Assumptions.

[20] Given we are using the expected peak load data based on Greenlink's analysis, cooling load at peak is likely to be close to 100 percent of the maximum cooling load. Thus, reducing the cooling peak savings by about 33 percent based on the coincident factor for cooling used by DC SEU likely understates the coincidence between cooling load savings and the peak.

Table 10. Peak savings profiles for energy efficiency measures for existing and ROB conditions (% of end-use load)

Segment	End Use	Peak Savings (Retrofit)	Peak Savings (ROB)	Peak Savings (Retrofit + ROB)	Peak Savings - Mid Case
Office	Lighting	19%	35%	53%	36%
Office	Cooling	2%	12%	14%	8%
Office	Refrigeration	19%	28%	47%	33%
Office	Electronics	24%	n/a	24%	24%
Hotels	Lighting	22%	35%	57%	39%
Hotels	Cooling	4%	11%	15%	9%
Hotels	Refrigeration	10%	28%	38%	24%
Hotels	Electronics	24%	13%	37%	31%
Multifamily	Lighting	15%	21%	36%	26%
Multifamily	Cooling	4%	9%	13%	8%
Multifamily	Refrigeration	27%	22%	49%	38%
Multifamily	Electronics	n/a	22%	22%	22%

There are a few more differences between our analysis and Greenlink's analysis. While we took some conservative approaches discussed above, we assumed that these savings assumptions shown as "Peak Savings – Mid Case" are applied to each large building in the SW Network region. In contrast, Greenlink assumed that a 65 percent of the building undergo retrofit, major renovation, or new construction for the next five years. Another difference in our approach is that our analysis included savings from refrigeration and electronics for large commercial buildings.

These differences explain different peak savings results to some extent between the two studies. Table 11 below presents our peak savings estimate for each building type as a percentage of building peak load. The sum of the savings estimates from lighting and cooling turns out to be about 13 percent for commercial buildings. This is slightly higher than Greenlink's final estimate of 12 percent for these buildings. On the other hand, our savings estimate of 17 percent for multifamily buildings is lower than Greenlink's estimate of 21 percent. This can be partly explained by the fact that Greenlink took a whole building approach for multifamily buildings.

Table 11. Energy efficiency peak savings estimates for existing buildings (% of building peak load)

	Lighting	Cooling	Refrigeration	Electronics	Total
Mixed use	10%	3%	2%	2%	18%
Office	10%	3%	0%	3%	17%
Hotel	10%	3%	1%	2%	16%
Multifamily	5%	4%	4%	4%	17%

For new construction buildings, we present in Table 12 our screening results for costs and savings based on the Pennsylvania study using the same approach we took for existing buildings as discussed above. Table 13 below then provides peak savings estimates for each building type for new construction.

Table 12. Peak savings profiles for energy efficiency measures for new construction (% of end-use load)

Segment	End Use	Peak Savings
Office	Lighting	34%
Office	Cooling	2%
Office	Refrigeration	18%
Office	Plug Load	18%
Lodging	Lighting	34%
Lodging	Cooling	4%
Lodging	Refrigeration	16%
Lodging	Plug Load	18%
Multifamily	Lighting	8%
Multifamily	Cooling	n/a
Multifamily	Electronics	22%
Multifamily	Refrigeration	22%

Table 13. Energy efficiency peak savings estimates for new construction (% of building peak load)

	Lighting	Cooling	Refrigeration	Electronics	Total
Mixed use	8%	1%	1%	1%	11%
Office	10%	1%	0%	2%	13%
Hotel	8%	1%	1%	1%	12%
Multifamily	2%	0%	2%	4%	8%

As the final step, we applied these peak savings factors to each of the 17 buildings in the SW Network Group area and estimated the total potential peak load savings from energy efficiency. Our analysis found potential cost-effective peak savings range from 36 kW to as high as 959 kW for the existing buildings, totaling close to 3,470 kW. If we take into account the recent savings of about 170 kW by DC SEU, the total peak savings result in about 3,300 kW. That this value is very close to the number estimated by Greenlink is coincidental, but provides some validation of our result.

For new construction, we estimate about 700 kW peak savings from energy efficiency at Capitol Crossing. However, there is a significant uncertainty about this savings estimate given that our load estimate for this building comes with much uncertainty. We can also expect more savings from unknown, future new construction building projects if DC SEU or other entities proactively approach them and make sure that they implement cost-effective energy efficiency measures and practices.

Pepco estimates an additional 25 MW or more of load. As mentioned above in this report, we have little clue where and how this level of additional load will emerge in the SW Network Group. However, if we apply the expected savings factors for mixed-use buildings shown in Table 13 above to Pepco's load forecast, we can expect to have an additional 2,700 kW or more of peak savings from these unknown future buildings. For new construction and existing buildings together, our analysis concludes that the cost-effective energy efficiency potential is at least 6.7 MW of peak load.

Lastly, note that there is a possibility that new buildings can be substantially more energy efficient than being estimated by the Pennsylvania potential study. There is a growing number of net-zero energy commercial buildings in the country. A study by the New Building Institute reveals that we have currently about 400 net-zero energy or ultra-low energy buildings in the nation, the majority of which were built over the last five years or so.[21] While the cost reduction of solar panels likely enabled this growth of net-zero energy buildings, state-of-the-art energy efficiency is essential to achieving net-zero energy commercial buildings. For example, a net-zero energy multifamily building built in Issaquah, Washington uses 78 percent less energy than the average with innovative efficiency designs such as daylighting and passive ventilation.[22]

Energy efficiency costs

According to the DC SEU's 2015 annual report, the DC SEU acquired 8.6 MW of summer peak reduction with about $13 million expenditures, resulting in about $1,542/first-year kW.[23] Because this represents the total program cost to reduce 8.6 MW for the lifetime of the measures implemented in 2015, annualized program costs are one-tenth of this amount or $154/kW-year. This assumes that the measures last about 10 years on average. Interestingly this is very close to what we found on the cost of demand response programs, which will be discussed below in the demand response section. However, energy efficiency provides more benefits than just peak load savings.

We are also interested in knowing the total resource cost including participants' costs. Assuming participants' costs account for 30 to 50 percent of the total resource cost (including both program costs and participants' costs), the total resource cost would be in the range of $2,200 to $3,000.

We also estimated costs of the energy efficiency potential as discussed above. The cost data were directly obtained from the 2015 Pennsylvania potential study. As we did for peak savings estimates, we estimated simple average costs among all measures we selected by end-use and building type. End-use-specific cost estimates are provided in Table 14 below for existing buildings, followed by cost estimates for new construction in Table 15. These costs represent measure incremental costs (i.e., cost premiums

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[21] New Building Institute (2016) *List of Zero Net Energy Buildings*, available a thttps://newbuildings.org/wp-content/uploads/2016/10/GTZ_2016_List.pdf.

[22] Ibid. p. 9.

[23] DC SEU (2016) ON THE MAP: Helping DC Lead in Sustainability - 2015 ANNUAL REPORT, available at https://www.DC SEU.com/docs/about-us/DC SEU-FY2015-Annual-Report.pdf.

beyond the costs of standard measures/practices) and do not include non-incentive program costs (e.g., marketing, administration, evaluation). A few costs are low in terms of $ per first-year kW (e.g., plug load for existing office buildings and refrigeration for new construction multifamily), but the majority of the measures cost from $1,400 to $2,500 per kW, and new construction measures are slightly lower on average across all measures. On the other hand, if we look at costs in terms of costs of saved energy over lifetime kWh, it becomes obvious that these costs are very low and close to each other almost across the board, ranging from $0.01 to $0.06 per kWh.

Table 14. Energy efficiency incremental cost profiles for existing and ROB measures

Segment	End Use	Average $/kW Summer Peak	Average Total Inc. Cost $/First Year kWh	Average Total Inc. Cost $/Lifetime kWh
Office	Lighting	2,508	0.21	0.02
Office	Cooling	1,532	0.47	0.04
Office	Refrigeration	1,389	0.24	0.03
Office	Plug Load	484	0.12	0.02
Hotels	Lighting	2,646	0.14	0.02
Hotels	Cooling	1,663	0.51	0.04
Hotels	Refrigeration	1,757	0.26	0.03
Hotels	Plug Load	1,357	0.57	0.10
Multifamily	Lighting	2,005	0.16	0.02
Multifamily	Cooling	1,091	0.33	0.04
Multifamily	Refrigeration	1,993	0.25	0.03
Multifamily	Electronics	1,357	0.31	0.06

Table 15. Energy efficiency incremental cost profiles for new construction measures

Segment	End Use	Average $/kW Summer Peak	Average Total Cost $/First Year kWh	Average Total Cost $/Lifetime kWh
Office	Lighting	1,784	0.21	0.02
Office	Cooling	1,169	0.62	0.06
Office	Refrigeration	1,827	0.21	0.02
Office	Plug Load	1,833	0.33	0.04
Hotels	Lighting	1,751	0.15	0.01
Hotels	Cooling	2,361	0.65	0.05
Hotels	Refrigeration	1,704	0.12	0.01
Hotels	Plug Load	1,833	0.33	0.04
Multifamily	Lighting	1,090	0.16	0.01
Multifamily	Cooling	n/a	n/a	n/a
Multifamily	Refrigeration	300	0.05	0.01
Multifamily	Electronics	1,664	0.19	0.02

To estimate incremental costs for the buildings in the SW Network Group area, we applied these cost factors to each building based on the building type and the share of end-use peak load contributions, as we did for estimating peak load savings. We also estimated expected incentive costs and non-incentive program costs based on the assumptions presented in Table 16. The resulting total program costs and total resource costs are presented in Table 17 along with the expected summer peak reduction and annual energy savings.[24] To tap into aggressive, but achievable cost-effective energy efficiency potential of about 3 MW from the existing buildings in the region, DC SEU or other entities need to spend about $3.6 million for incentives and other program costs. For new construction buildings, we expect an equal amount of funding is needed to obtain an additional 3 MW, assuming that Pepco's load forecast for unknown, future new construction is correct.

Table 16. Cost share for measure incentive and other program costs

	Cost (%)	Note
Incentive (% of Total Inc. Cost)	40%	Current incentive level by DC SEU
Other program cost (% of Total Resource Cost)	30%	Non-incentive costs range from 15% to 40% according to ACEEE (2014).

Table 17. Costs and savings of energy efficiency potential in SW Network Group

	Existing	New Construction	Total
Savings Estimates			
Summer Peak Reduction (MW)	3.3	3.4	6.7
Annual Energy Savings (GWh)	23.9	33.2	57.1
Program Cost Estimates			
Incentive ($ million)	2.5	2.7	5.2
Other Program Costs ($ million)	1.1	1.1	2.2
Total Program Costs ($ million)	3.6	3.8	7.4
Total Resource Cost			
Total Resource Cost ($ million)	7.4	7.9	15.3

Lastly, we present average costs of saved energy and peak load in Table 18. Both existing and new construction measures and projects cost about $1,000 to $1,100 per kW as the program cost, and about $2,100 to $2,200 per kW as the total resource cost. From an energy perspective, they cost about $0.12 to $0.15 per kWh-year from the program perspective (or one tenth of this amount over the lifetime of the measures, assuming an average of 10-year measure life), and $0.24 to $0.31 per kWh-year from the total resource cost perspective.

[24] Annual energy savings were estimate for each building using (a) end-use "energy consumption" breakdown data based on EIA's CBECS data and NEMS building data for AEO 2015, and (b) energy savings estimates by end-use and building type.

Table 18. Average cost of energy efficiency potential in SW Network

	Existing	New Construction	Total
Program Cost Estimates			
Total Program Cost ($/kW)	1,039	1,116	1,078
Total Program Cost ($/kWh-year)	0.15	0.12	0.13
Total Resource Cost			
Total Resource Cost ($/kW)	2,131	2,288	2,209
Total Resource Cost ($/kWh-year)	0.31	0.24	0.27

Value beyond feeder peak reduction

Energy efficiency creates value in the electric utility system beyond helping to defer substations. It avoids energy production and consumption, reduces the need for generating capacity, and reduces the cost of maintaining a reliable transmission system. It also reduces the emission of pollutants. An energy efficiency-based non-wires alternative can be cost-effective even if the cost to implement the efficiency exceeds the savings on the distribution system, as long as the other benefits swing the cost-benefit balance back in favor of efficiency.

For our analysis of the other benefits of efficiency, demand response, storage, and other DERs, we have used the values that are used to characterize the benefits of DC SEU programs. We adapted those values into nominal dollars and used the DC SEU assumption of 1.7 percent future inflation to take current-only values and carry them into the future where necessary. We do not have the load shapes around the year of the potential energy efficiency portfolio, so we used a simple average of the summer and winter on- and off-peak energy values. Given our focus on measures intended to address summer peak (such as HVAC), it is more likely that the average energy value understates the avoided energy value. We have included avoided distribution costs in Table 19, but have not used it in our initial NWA screening in Section 6. This is to avoid possible double-counting with the avoided value of the Mt. Vernon Square substation.

Table 19. Avoided costs of capacity, energy, transmission, distribution, and externalities, 2018–2030

Long Run Avoided Costs (in nominal $)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Avoided Generation Capacity ($/kW-yr)	$73.53	$78.85	$84.57	$90.72	$97.29	$104.35	$111.92	$120.03	$128.74	$138.08	$148.10	$158.84	$170.37
Avoided Energy ($/MWh)	$65.44	$65.83	$66.77	$67.88	$70.72	$72.75	$74.55	$77.04	$79.11	$79.78	$82.09	$83.92	$85.97
Winter Peak	$64.58	$65.06	$65.64	$67.61	$70.39	$72.14	$74.15	$75.07	$77.51	$79.30	$81.13	$83.00	$85.66
Winter Off-peak	$52.68	$53.06	$55.12	$54.99	$58.75	$59.86	$62.79	$63.97	$64.94	$66.64	$68.61	$70.15	$72.09
Summer Peak	$93.36	$93.81	$94.67	$95.74	$98.46	$101.35	$101.83	$104.48	$107.07	$108.77	$111.83	$114.71	$116.53
Summer Off-Peak	$51.16	$51.40	$51.65	$53.17	$55.27	$57.65	$59.41	$64.66	$66.92	$64.39	$66.81	$67.82	$69.60
Avoided Transmission Costs ($/kW-yr)	$23.63	$24.64	$25.66	$26.68	$27.69	$28.71	$29.73	$30.75	$31.76	$32.78	$33.80	$34.81	$35.83
Avoided Distribution Costs ($/kW-yr)	$206.20	$207.22	$208.23	$209.25	$210.27	$211.29	$212.30	$213.32	$214.34	$215.35	$216.37	$217.39	$218.40
Avoided Externalities ($/MWh)	$48.61	$49.96	$50.49	$41.72	$24.70	$30.98	$31.51	$30.67	$70.41	$83.09	$102.20	$105.40	$89.89

5.2. Distributed generation

Generation on customer premises can lower peaks, increase reliability and resilience, and help the District meet renewable energy goals.

Solar PV

Pepco's hosting capacity maps identify the limits of power injection from solar PV that are possible onto the SW Network Group, the West Group, and radial feeders 15461 and 15462.

Table 20. Pepco hosting capacity for feeders and networks served by Northeast Sub #212

Section	Maximum Allowable PV Capacity (kW)
SW Network	610
West Network	370
15461	251–1,000
15462	3,001–6,000

We conducted a GIS-based analysis of the rooftops of existing buildings among the large buildings we identified that are served by the Northeast Substation #212.[25] We identified a cumulative potential of approximately 5 MW of rooftop PV, of which about 2 MW is on buildings in the SW Network Group. The largest opportunity is on the roof of the General Accountability Office (about 700 kW), but the combined circumstances of a historic building and Federal ownership may complicate deployment there. The roof of the National Building Museum could hold about 250 kW, but deployment is unlikely due to the sloped roof (because solar can't be hidden as on a flat roof) and historic nature of this building. About 1 MW of possible capacity remains on the commercial building rooftops in the SW Network Group.

For NWA analysis, we have assumed that 1 MW could be achieved on the SW Network Group, despite Pepco's PV hosting capacity limit of 610 kW. Pepco has identified that any solar at all on the SW Network Group would require further study. Pepco's limits are related to concerns from power injection onto the grid. The buildings that could host solar in this area are multi-story large office and multifamily buildings with minimum loads on most days well in excess of the generation their roofs can host. Coupling solar PV with batteries, or even shedding power instead of injecting it on the grid, can further ensure that this resource is present for NWA planning. If for some reason PV capacity absolutely must

[25] See the "Distributed Solar in the District of Columbia" published by the Office of the People's Counsel (http://www.opc-dc.gov/images/pdf/solar/Synapse-DC-Solar-Report-April1217.pdf) for details on the methodology.

be limited to 610 kW instead of 1 MW, the additional 390 kW[26] of batteries, efficiency, or demand response may be straightforward to achieve.

The assumed 1 MW of solar PV should produce more than 1,100 MWh of energy and RECs each year (together worth more half a million dollars at current REC prices), while contributing to avoiding capacity costs. We estimate that rooftop PV on these commercial buildings could be constructed for about $3.50 per watt of capacity, or a total of about $3.5 million for the 1 MW of potential. The District's solar carve-out (SREC) program would allow the project owners a payback of about five years, so the need for additional ratepayer support may be limited.

Greenlink's analysis indicates a likely late afternoon (3–5pm) peak on the SW Network Group. Typical solar PV installations are oriented to face south, maximizing total energy generation. Such a facility would be generating only about 20–40 percent of its maximum capacity at the time of a late afternoon peak.[27] We have used a conservative 25 percent peak coincidence factor when including PV in an NWA portfolio.

Cogeneration

On-site cogeneration of heat and electricity can use fossil fuels more efficiently than at remote power plants. It can meet both heat and cooling needs and limit a building's need to draw on the electric grid. Buildings likely need to be designed from the beginning to utilize a cogeneration facility in order to harness this resource. However, in the SW Network Group, Pepco is clearly expecting significant new construction. The largest proposed project—Capitol Crossing—is already planning to utilize cogeneration sufficient to meet its on-site energy and heat needs.[28]

Fuels cells are more efficient than combustion-based cogeneration at producing electricity, but are not well suited to combined heat and power. They are most cost effective when run around the clock, removing a flat portion of load from the grid. As such, fuel cells could be effective for reducing peak loads to the extent they reduce all other loads as well. Fuel cells may be particularly attractive for users that have 24/7 electric demand in the building, such as buildings that host data centers. The Metro office at 600 5th St NW (in the SW Network Group) has an on-site data center and 24/7 operations center, and these could benefit from the additional reliability and resilience that on-site generation offers.

We have not developed cost estimates for cogeneration or fuel cells, nor have we included them in the example NWA portfolios we present later. However, new construction in particular should explore these options as part of any subsequent detailed NWA examination.

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[26] We assumed that 390 kW of solar PV would offer less than 100 kW of coincident peak capacity.

[27] Estimated using late afternoon performance calculated by PVWatts, http://pvwatts.nrel.gov/

[28] WJLA, "Capitol Crossing project, DC's first eco-district, brings jobs, parks, views, tax revenues," http://wjla.com/news/local/capitol-crossing-project-dcs-first-eco-district-brings-jobs-parks-views.

5.3. Demand response

A variety of demand response technologies and measures are available to reduce peak load consumption for end-use devices for different types of customer segments existing in the Mt. Vernon area at low costs. Large commercial buildings including office buildings and hotels can use a number of different technologies to reduce their peak load as follows:

- **Energy management system** (EMS): One of the common technologies is building energy management systems (EMS) which enable building energy managers to monitor and control lighting, air conditioning, ventilations, fans, and other equipment and appliances. For example, hotels can use EMS to make minor temperature adjustments of their air-conditioning in common areas, dim lights, turn off fans and fountains and other non-essential electricity consuming devices without affecting guests' comfort and hotel operations.[29]

- **Backup generator**: Another common approach is to use a backup generator for a short period of time to reduce peak demand. Many buildings are likely to have diesel generators as a backup generator. While emissions from generators are concerns, demand response programs allow EPA-approved generators as the programs only require a limited number of hours of curtailments.

- **Thermal storage**: Thermal or ice storage technologies have existed for a long time, but have recently gained renewed attention as a peak load reduction measure. Ice Energy, a provider of the ice storage system called Ice Bear System, estimates that their system can cut peak AC power consumption up to 95 percent while enabling businesses to save up to 30 percent on electricity bills.[30] Ice Energy has partnered with NRG Energy to deploy 1,800 ice storage systems (totaling up to 25.6 MW) on commercial and industrial buildings in Southern California over the next four years.[31] This deployment is part of Southern California Edison's battery and power procurement efforts, in which the utility controls the ice energy systems for peak load reduction.

Pepco can send curtailment signals to building energy managers via internet, email, phone, or pager. In response, large commercial customers can curtail their load using the technologies mentioned above. This is the same approach Pepco is taking for PJM's wholesale demand response program, but one difference is that Pepco would focus on the SW Network Group or any other distribution load constrained areas, instead of the system-wide area. As an example, Orange & Rockland utilities in New York has three types of demand response programs, one of which is called the Distribution Load Relief

[29] See this article for Seaport Boston Hotel's example, http://www.greenlodgingnews.com/how-demand-response-can-turn-your-hotel-into-virtual/.

[30] http://www.nrg.com/business/large-business/services/energy-management/icebear-system/.

[31] https://pv-magazine-usa.com/2017/04/13/worlds-largest-deployment-of-ice-batteries-begins-in-southern-california/; https://arstechnica.com/information-technology/2017/05/ice-batteries-commissioned-by-utility-will-cool-california-businesses/.

Program (DLRP). This program solicits load reductions from large commercial customers in distribution load constrained areas.[32] For our study, we call this option "Mt. Vernon large commercial DR program."

Multifamily buildings may be more complicated for demand response because a large share of the building load belongs to numerous residential customers while some loads belong to common areas and common facilities such as swimming pool and fitness centers. Thus, a different approach is required for these customers. One typical and major approach is to control residents' air-conditioning units. Traditionally, utilities installed air-conditioning cycling switches to air-conditioning compressors in order to cycle on and off. This allows utilities to reduce energy usage during peak times while often allowing residents to override utility controls.[33] More recently, as Wi-Fi-enabled thermostats have become widely available, a growing number of utilities have adopted this technology to remotely control thermostats' temperature and reduce residential peak load.[34] For our study, we call this option as "Mt. Vernon multifamily DR program."

Potential peak load reduction from demand response

Program experience shows that the potential of peak load demand reduction largely depends on the amount of incentives and the duration of demand response activities over the course of a program year. In contrast, peak reduction potential for residential customers is significantly affected by the availability of enabling technologies. To reflect this experience, we took different approaches for estimating demand response potential for the multifamily buildings and for the rest of the large commercial buildings as follows.

Multifamily buildings

For multifamily buildings, we reviewed the performance of existing residential demand response programs and developed our own savings assumption per resident for multifamily building. Our key assumptions for multifamily buildings are presented in Table 21 below.

Table 21. Key demand response assumptions for multifamily buildings

	Value
Per Customer Savings (% of Peak Load)	25%
Participation Rate (% of Eligible Customers)	70%

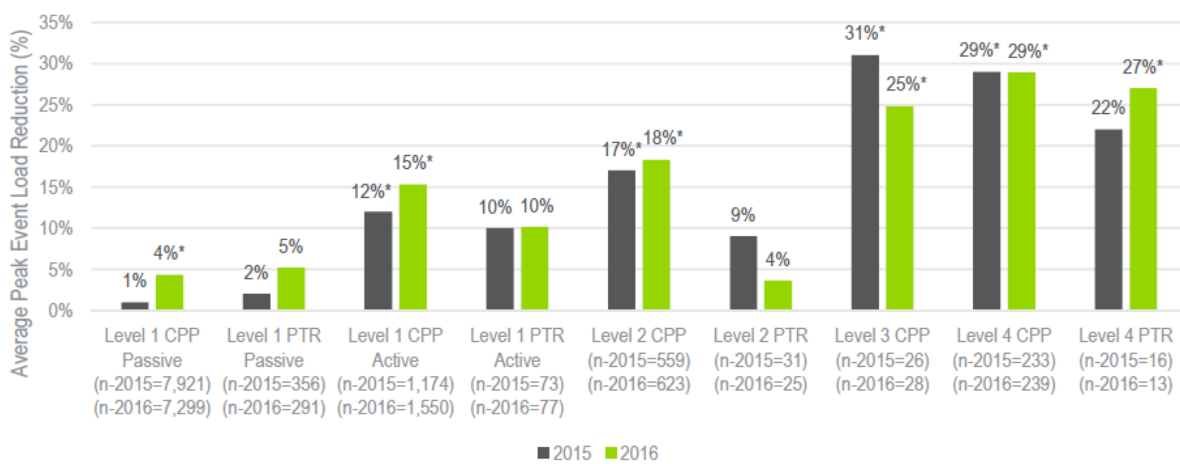
[32] O&R (2016). Orange & Rockland Utilities, Inc. Annual Report on Program Performance and Cost Effectiveness Of Dynamic Load Management Programs, December 1, 2016.

[33] A list of residential demand response programs is available here, https://www.clearlyenergy.com/residential-demand-response-programs

[34] Another potential end-use for residential DR is electric hot water tanks which can store thermal energy during off peak times and limit water heating during peak hours. However, our study does not include this DR approach given the data limitations about the costs and performance of this approach.

Our assumptions are mainly based on the performance of the residential demand response pilot program implemented by National Grid in Massachusetts, along with data for a few other pilot programs. National Grid's pilot program, called the Smart Energy Solutions Pilot program, offered an opt-out dynamic pricing option to about 15,000 customers from January 2015 through 2016. It tested, among other things, peak load reduction impacts from three types of dynamic pricing options and advanced customer-side technologies (also called demand response enabling technologies). The pilot program found a wide range of peak load reductions, from a few percent to 30 percent, depending on the type of pricing schemes and technology options (Figure 12).[35] Between the two pricing options—critical peak pricing (CPP), which increases electricity prices substantially for super peak times, and peak time rebate (PTR)—CPP generally had a larger peak load impact. In addition, participants with more enabling demand response technologies (represented with higher levels among Level 1 through 4 in Figure 12) show greater impacts. Among all pricing and technology options, Wi-Fi-enabled thermostats appear to have had the largest impact on peak load. The participants with the advanced thermostats under Level 3 and Level 4 technology packages both reduced a similar level of peak load ranging from about 22 percent to 30 percent peak load.

Figure 12. National Grid pilot results: average peak event load reductions by technology/price group



Note: "Passive" participants are those who have no in-home technology and have not visited the Web portal established for this pilot program.

An evaluation study of National Grid's pilot program also reviewed peak load impacts from other programs. It found a similar level of impacts from demand response programs that offered Wi-Fi enabled thermostats, ranging from 25 percent to 35 percent average peak load reductions. Thus, we assumed a 25 percent reduction for our study.

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[35] Navigant (2017). National Grid Smart Energy Solutions Pilot, Final Evaluation Report.

We assumed a high participation rate based on an opt-out program approach. Many pilot studies that implemented an opt-out approach found very high retention rates, ranging from 85 percent to 98 percent.[36] Thus, our assumption of 70 percent for the SW Network Group area is conservative.

Large commercial buildings

For the rest of the large commercial buildings, we estimated potential peak reduction based on incentive amounts, price elasticity data, and the duration of curtailments. This methodology was developed by a 2015 demand potential study for Pennsylvania ("PA DR study"),[37] and later also adopted by a 2017 demand response study for Michigan.[38]

More specifically, the peak reduction expressed as $\%\Delta Q$ can be calculated by the formula presented below.

$$\%\Delta Q = \frac{(P_1 - P_0)}{P_0} * \epsilon$$

Where, P_0 represents retail electricity rate ($/kWh),
P_1 represents the incentive level in terms of $/kWh,
ϵ represents price elasticity

The incentive level can be calculated by dividing the incentive amount in $ per kW-year by the number of load curtailment hours for the entire season or year.

The Pennsylvania demand response study examined various demand response programs and developed price elasticity for various commercial buildings for three types of demand response programs, namely Day-Ahead, Day-of, and Fast-Response programs.

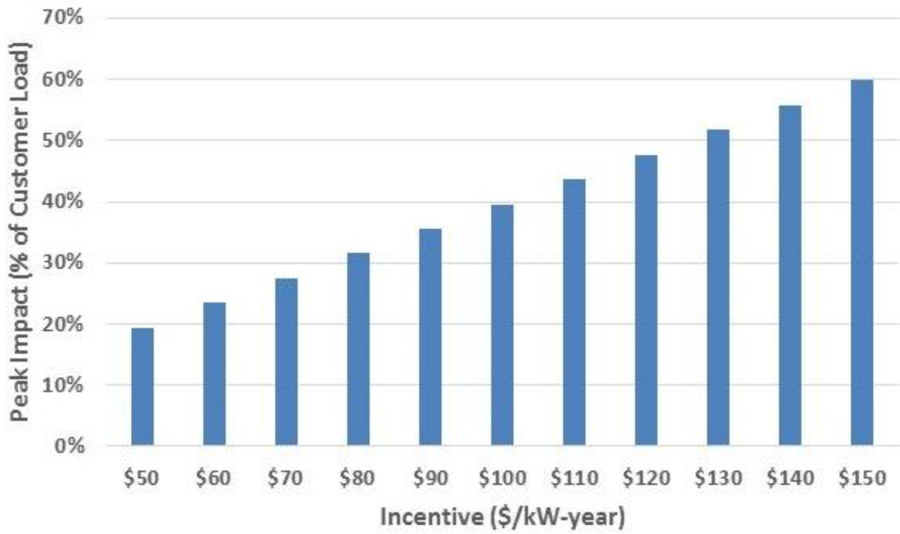
The resulting peak reduction impacts with the study method is shown below in Figure 13 for large commercial buildings in the District. The peak impacts range from about 20 percent reduction with a $50/kW-year incentive level to about 60 percent with a $150/kW-year incentive level. Note these impacts do not yet take into account rates of participations or eligible customers.

[36] Navigant (2017), Figure 4-12.

[37] GDS Associates (2015) Demand Response Potential Pennsylvania.

[38] Demand Side Analytics and Optimal (2017). Economic Potential for Peak Demand Reduction in Michigan.

Figure 13. Per customer peak reduction potential for large commercial buildings in DC



The key assumptions for these potential estimates besides the incentive levels are:

- An average commercial electricity rate of 12 cents per kWh for DC based on EIA 861 data for 2015.
- Four curtailment events per year with a four-hour duration for each event, totaling 16 hours for each summer/year.
- Price elasticity data for hotels and office buildings for the Day-Ahead and Day-Of markets.

It is also important to note that the highest peak impact of 60 percent is comparable to what Orange & Rockland Utilities (O&R) has achieved for its DLRP program, which was about 19 MW reduction from 27 large commercial customers in 2016 (or 65 percent of its total customer peak load).[39]

Finally, we assumed 50 percent of the large commercial buildings are eligible and capable of reducing load under Pepco's targeted demand response program. This assumption is based on the customer eligibility rate used by the 2017 Michigan demand response potential study for commercial buildings. In contrast, the 2015 Pennsylvania study assumed about 70 percent of large commercial and industrial customers are eligible or capable of participating in a demand response program for PECO's territory.[40]

Using the assumptions discussed above, we estimated that the 17 existing buildings could provide a total of 4.4 MW of demand response, and Capitol Crossing could provide about 1.8 MW. If Pepco's load

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[39] O&R offers incentives of $3 to $6 per kW-month along with $0.5 per kWh for the duration of the curtailment events. Given that the incentive structure by O&R takes a performance incentive per kWh energy savings, it is difficult to compare its impact to other programs.

[40] The total eligible load is 3,442 MW (Table 2-3) and the total C&I load is 4,967 MW (Table 2-2) according to GDS Associates (2015).

forecast for unknown future buildings is correct, we could also expect to have more than 6.5 MW of additional demand response from those buildings.

A note on load shifting

To the extent that buildings shift loads from peak times to other portions of the day in response to demand response signals (as opposed to conservation or the use of backup generators), the demand response potential is limited by the load shape. Creating a new peak of the same height at a different time does not solve the network's feeder constraint issues. This is not a concern for demand response only: the amount of demand response we have projected (4.4 MW for existing buildings) is short of this level, even if all of the demand response were achieved through load shifting. However, further analysis of NWA portfolios should carefully account for the potential of interaction between demand response and storage if both rely on load shifting from on-peak to off-peak hours.

Demand response costs

We developed demand response program cost estimates largely based on O&R's demand response programs. For the multifamily demand response program, we assumed the total cost of the program is $250 per kW-year.[41] This value is based on O&R's Direct Load Control Program (DLCP) data for 2016 and includes all program costs for customer incentives, program implementation, marketing, and evaluation. DLCP remotely controls central air-conditioning equipment in customers' homes and small businesses with Wi-Fi enabled smart thermostats during peak shaving or contingency events. The company offers two options for thermostats. The first option is to offer free or low-cost smart thermostats to customers. The second option is a Bring Your Own Thermostat (BYOT) option where customers receive $85 for participation. All customers receive $25 for the second summer and each year thereafter if they remain in the program.

For the large commercial demand response program, we assumed that incentives account for 90 percent of the total program cost as shown in Table 22. This assumption is loosely based on the 2016 expenditures for O&R's DLRP program. As O&R's program did not call any demand response resources under this program and only once tested customers' responsiveness and levels of load reduction, the total incentive amounted to about 80 percent of the program cost. For our study, we assumed a higher share of program incentives as shown in the table below.

Table 22. Program cost breakdown for the large commercial demand response program

	Incentive	Other Program Cost
Large Commercial	90%	10%

[41] Orange & Rockland (2016). Orange & Rockland Utilities, Inc. Annual Report on Program Performance and Cost Effectiveness of Dynamic Load Management Programs, December 1, 2016.

Participants' own costs are generally not available for demand response programs, and these are sometimes difficult to estimate for large commercial customers. This is primarily because such customers use various approaches to reduce peak demand. For EMS and backup generators, there are no additional capital costs for the participants, as we expect customers who will participate and use these technologies already have them. Operational costs should be minimal for EMS as buildings should already have an energy system manager who manages EMS for any demand response programs. For backup generators, the major operational cost is the cost of diesel or natural gas fuel. Another option discussed above is ice storage for HVAC. Where Ice Energy deploys its ice storage system, the company often partners with a utility that will offer the technology along with a new power procurement arrangement inclusive of the cost of the technology.[42] Thus, there is no participant cost for this option, but we still need to know how much it would cost. Unfortunately, the companies or utilities that deploy this technology have not disclosed product costs in a meaningful way. However, based on a recent pilot program case by Eversource in Massachusetts, it appears this technology can be cost-effective even in a state with low air-conditioning demand. Eversource's program cost just for ice storage is $3.9 million for delivering 0.4 to 8.5 MW. This results in $460/kW to $10,000/kW over the lifetime (excluding future operational costs).[43] This implies that annual costs could be from about $42 to $940/kW-year assuming a measure life of 15 years and a 5 percent discount rate.

Lastly, we present our estimate of total program costs for the demand response programs for the SW Network Group area, as shown in Table 23. We expect that Pepco needs to spend slightly less than $1 million to obtain 4.4 MW of demand response from the existing buildings and about $1.4 million to obtain 8.5 MW of demand response from Capitol Crossing and unknown future buildings. Note that these annual program costs are much lower than the program costs shown for energy efficiency potential as discussed above. This is because the cost for efficiency represents lifetime costs, while the cost for demand response represents annual program costs. This means that Pepco needs to keep investing at these levels each year until the proposed substation is constructed or canceled if Pepco desires to maintain the level of demand response from these buildings.

Table 23. Annual program costs for demand response potential in SW Network

	Existing	New Construction	Total
Incentive ($ million)	0.6	1.3	1.9
Other Program Costs ($ million)	0.2	0.1	0.3
Total Program Cost ($ million)	0.8	1.4	2.2

[42] Walter, R. (2017). "Ice Energy, NRG installing new energy storage solutions for SoCal Edison." Utility Dive, April 13. Available at: http://www.utilitydive.com/news/ice-energy-nrg-installing-new-energy-storage-solutions-for-socal-edison/440436/.

[43] Eversource (2016). Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval to Implement Demand Reduction Demonstration Offerings and Associated Budget. Docket DPU 16-178, available at http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=16-178%2fInitial_Filing.pdf

5.4. Battery storage

Battery storage can be deployed in a variety of configurations and ownership models to contribute to lowering peak demand in the SW Network Group. The primary points of difference are the system's *ownership* and its *electrical location*.

A battery storage resource could be owned by either the utility or a third party (such as a building owner). The resource could be electrically "behind" a customer meter or it could be directly connected to the utility's network as though it were its own customer. In each case we have considered, Pepco would have either direct or contractual control over the asset. Thus, the utility would be able to count on that resource's capacity for all planning purposes. Here is how the resource could work under each combination of these configurations:

- **Utility-owned; directly on the grid:** Pepco would have complete control over the batteries. It would charge or discharge them as appropriate to shave peaks on the circuit, mitigate PJM transmission and generation capacity costs, provide regulation service in the PJM markets, and even conduct arbitrage between night-time and day-time energy prices.[44]

- **Utility-owned; behind a customer meter:** Pepco would identify customer partners and the utility and customers would work out a joint agreement regarding the use of the batteries. Customers might want to be able to manage their monthly demand peaks to their bill advantage and also maintain uninterruptible power, while Pepco would like to do as much as possible to control costs or earn revenues as identified above. Pepco and the host customers would come to mutually agreeable arrangements for facility access and services provided to the customers.

- **Third-party owner; directly on the grid:** In this circumstance, Pepco would contract with an independent energy company, similar to a utility-independent generator relationship at the transmission level. Pepco would contract for the ability to control the battery in the few peak days of the summer, while the independent owner would provide wholesale market services (such as regulation and capacity).

- **Third-party owner; behind a customer meter:** Here the customer would be king, with the primary perceived value being uninterruptible power and demand charge management. The customer could sell the system's capabilities into the wholesale markets. This is the configuration that Pepco has used as an example of a storage installation that it could not count on for distribution planning purposes.[45] However, since Pepco will have contracted with the customer to provide control of the battery system to Pepco for the few days a year necessary to play its role on the distribution system, it could transition into being a reliable resource for the purposes of planning.

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[44] Duke Energy is constructing two such batteries; see Utility Dive, "Duke to build its first utility-scale regulated battery storage projects" at http://www.utilitydive.com/news/duke-to-build-its-first-utility-scale-regulated-battery-storage-projects/505374/.

[45] Pepco, "Distributed Energy Resources and the Distribution System Planning Process." (2016) page 16.

Pepco's hosting capacity analysis for solar PV provides some insights as to the possible limitations and behavior of a battery system as well. Pepco has identified a capacity for up to 610 kW of solar PV on the SW Group. As discussed in Section 5.2, this limitation is fundamentally about the export of power from customer facilities and would apply to storage as well. (The hosting capacity analysis might be re-run with different load shapes for battery export and generate somewhat different limits.) Battery storage that manifested itself as a reduction in load from customer facilities, rather than as power export on to the grid, should not be subject to this same limitation.

Battery storage costs

Lazard published its "Levelized Cost of Storage Analysis—Version 3.0" in November 2017.[46] This report describes the cost of different battery technologies designed for different applications. Lazard analyzes a "distribution" primary use case which is a serviceably close parallel to the Mt. Vernon situation. Lazard describes this case as "Energy storage system designed to defer distribution upgrades, typically placed at substations or distribution feeder controlled by utilities to provide flexible peaking capacity while also mitigating stability problems (typically integrated into utility distribution management systems)."

Lazard's distribution case is specified as a 10 MW battery with six effective hours of storage and 60 MWh total energy capacity. Lazard anticipates it would cycle once a day, 350 days per year. The unit would supply 21,000 MWh of usable energy per year for 20 years. Lazard estimates a range of costs of between $272/MWh and $338/MWh for this application for lithium-ion technology, which is the current market leader among grid-connected battery types. These ranges translate to a levelized 20-year cost of their specified battery at $5.7 to $7.1 million per year. The "microgrid" case, for a 1 MW four-hour battery, has costs that are about 15-30 percent higher ($363 to $386/MWh). Lazard projects a 10 percent annual cost reduction for lithium ion technology, and 36 percent over the next five years. About 40 percent of these costs are for debt and equity associated with the purchase (and replacement as necessary) of the physical hardware; the remainder covers operating cost, the net cost of energy from charging, and taxes. Total initial installed cost of a 10 MW, six-hour lithium-ion battery would be expected to range between $22.0 and $28.3 million.

For application in Mt. Vernon, the battery size and its associated cost would scale by a combination of the peak demand to be supplied and the number of hours over which the demand must be reduced.

Scaling a battery for Mt. Vernon

Pepco provides sample load shapes for different customer classes. We combined the residential master metered apartments and low-voltage general service load shapes in the proportion represented by the blend of residential and commercial loads in the SW Network Group on the peak day from Greenlink's analysis. This approximates the load shape during a peak that could stress the feeders supplying the network. The load shape is important for sizing a battery to contribute to a non-wires alternative

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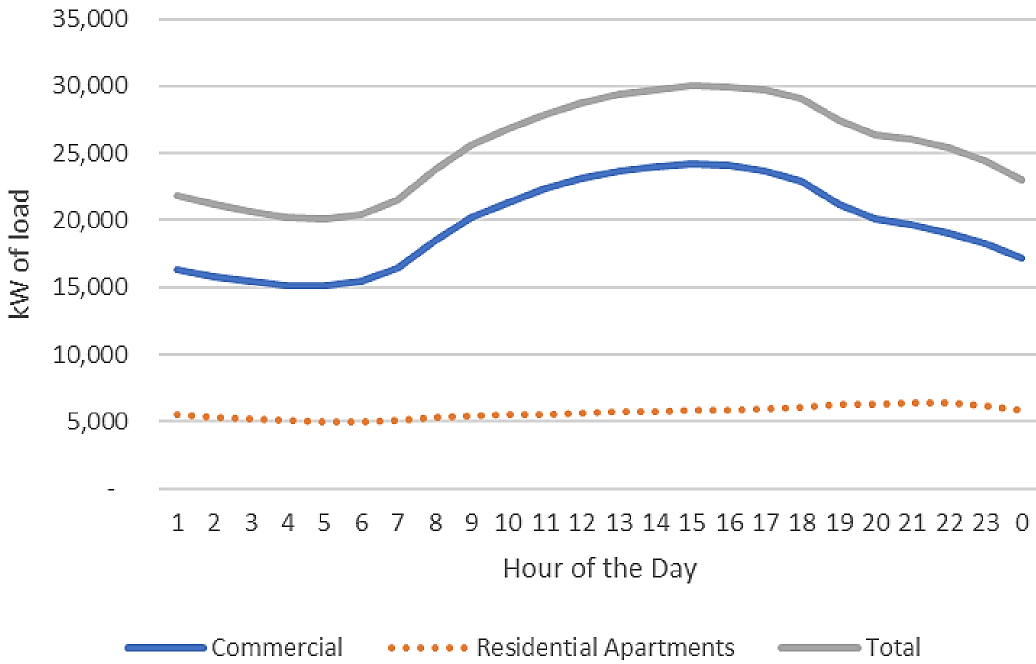
[46] See: https://www.lazard.com/perspective/levelized-cost-of-storage-2017/.

because the energy-to-capacity ratio of the battery should reflect the length of the peak. A short, sharp peak could be addressed by a battery with just one or two hours of storage at maximum output, while a long flat peak may require much larger batteries.

Figure 14. Approximate peak day load shape on the SW Network Group, including Capitol Crossing



The load shape also limits the extent to which a battery alone can reduce the network group's peak. Because the battery needs to be charged from the same network, when it reduces the peak it raises the load during the overnight "valley" in the load shape. At some point the valley is full, the load is flat, and batteries can no longer reduce the load. (Some amount of charging from previous days could relax this limit somewhat, although peak days tend to come in clusters so Pepco would likely need to deploy the batteries multiple days in a row. Pepco may also be using the battery to provide other services, limiting its ability to charge for multiple days in anticipation of a peak.)

For the load shape we estimated for the SW Network Group,[47] the limiting extent of peak reduction from batteries is 13 percent of the peak, or about 4 MW. If Pepco is right that the load on the SW Network Group will grow to 63.4 MVA, then this implies a limiting battery size of about 8.4 MVA, or 8.0 MW of real power, across the network (in one or more installations).

The duration of the battery needs to grow with its increasing power output capacity. For example, cutting the peak by 1 MW would require a 3.5 MWh battery, while cutting the peak by 3 MW requires

[47] This load shape includes as estimate of Capitol Crossing based on scaling another recent office building to that project's 2.2 million sq. ft., as discussed in Section 3.4.

an 18.4 MWh battery. Table 24 shows the required energy associated with each capacity, for the SW Network Group as it exists today.

Table 24. Energy storage required with each peak reduction capacity for a standalone battery on the SW Network Group

Battery Power (MW)	Battery Energy (MWh)	Peak Reduction (%)
1	3.5	3.3%
1.5	6.6	5.0%
2	10.1	6.7%
2.5	14.0	8.3%
3	18.4	10.0%
3.5	23.1	11.6%
4	28.5	13.3%

The cost to deploy and operate batteries will scale with the power and energy required. Table 25 shows our estimate of the capital cost range for batteries designed to reduce Pepco's forecasted 63.4 MVA (60.2 MW) peak by increasing amounts. For our NWA analysis, we used the average of the high-end and low-end costs; in practice, competitive procurement and falling technology cost over time should drive the cost toward the lower end of the range. Given the timeline for the NWA (using a battery starting in 2023), we included the 36% expected 5-year fall in capital costs that Lazard projects.

Table 25. Capital cost range for different sizes of lithium-ion batteries scaled to reduce the SW Network Group peak from Pepco's projected level by increasing amounts

Battery Capacity (MW)	Peak Reduction (MVA)	Peak Reduction (%)	Battery Energy (MWh)	Low-End 2017 Capital Cost ($ millions)	High-End 2017 Capital Cost ($ millions)	2023 Estimated Capital Cost ($ million)	2023 NPV O&M and Charging Costs ($ million)
2.0	2.1	3.3%	7.0	2.6	3.3	1.9	2.0
3.0	3.2	5.0%	13.3	4.9	6.3	3.6	3.7
4.0	4.2	6.7%	20.3	7.5	9.6	5.5	5.7
5.0	5.3	8.3%	28.1	10.3	13.2	7.5	7.8
6.0	6.3	10.0%	36.9	13.6	17.4	9.9	10.3
7.0	7.4	11.6%	46.4	17.1	21.9	12.5	12.9
8.0	8.4	13.3%	57.1	21.0	27.0	15.4	15.9

Using the average costs, we can estimate the cost per incremental kW of peak reduction from batteries. As the peak reduction required increases, the battery grows faster because it has to provide more energy in proportion to its peak capacity; this increases the cost per incremental kW. Operations and maintenance costs add to this capital cost per kW. At these costs per kW of peak reduction, batteries make sense if they provide added value such as resilient power or capacity savings, are a component of avoiding the need for the new substation for multiple additional years (or complete avoidance), or both.

Table 26. Estimated 2023 cost per incremental kW of peak capacity for a range of battery sizes

Battery Capacity (MW)	$ per incremental kW
2.0	$942
3.0	$1,689
4.0	$1,882
5.0	$2,074
6.0	$2,368
7.0	$2,559
8.0	$2,873

Coupling batteries with generation

The limit to 8.0 MW (8.4 effective MVA) of batteries, identified above, holds as long as the batteries need to charge from the grid. However, if the batteries can charge from on-site generation, this limit no longer applies. Batteries would allow Pepco to effectively time-shift generation, including solar or on-site cogeneration, to full coincidence with the peak times.

When deployed alongside batteries, solar PV serves several functions: it charges the battery without requiring a draw from the electric grid, and it both lowers and shortens late afternoon peaks. Solar PV can therefore make a battery system more flexible and reduce the amount of energy it needs to store relative to its power capacity. Given that on-site generation would also be deployed to meet the peak itself, a reasonable approximation is that on-site storage could allow solar PV to contribute its full nameplate capacity to meet the peak, even if that peak is happening when the sun is not at its peak. Battery systems coupled directly with solar PV systems may also be able to take advantage of the solar investment tax credit, although there is some uncertainty regarding Internal Revenue Service treatment of such claims.

We estimate that the effective maximum capacity of on-site cogeneration could be doubled through appropriate up-sizing of the battery system. In this case, the cogeneration system runs to charge the extra battery capacity during the off-peak hours and then runs to cut the peak directly during on-peak hours.

Batteries provide value other than feeder peak reduction

When integrating a battery storage system into an NWA framework, we need to account for values that the system would provide beyond avoided distribution cost. This is the same as counting the energy savings that accompany using energy efficiency to reduce feeder peaks, or the capacity savings that can accompany demand response.

From the utility system perspective, the value from batteries can be approximated in avoided capacity costs, avoided transmission costs, and revenue from providing regulation service. Avoided capacity and transmission can be calculated from the DC SEU avoided cost values, exactly as for energy efficiency.[48] Using these values, a 1 MW battery deployed in 2018 and in use through 2030 would provide a present value of benefits to ratepayers of $1.2 million. The PJM regulation market has historically been a promising source of revenue for energy storage. However, low prices, abundance of supply from battery systems already deployed, and changing market rules make this less promising. We have not included any regulation revenue in our analysis, although it is likely that some additional benefit could be obtained over a battery system's lifetime.

Customers deploying energy storage behind the meter would see two particular sources of value: uninterruptible power and reduction in demand charges. While downtown DC has quite reliable power (e.g., the underground distribution system is not subject to tree-or squirrel-related outages), protection against larger-scale outages will have some value to customers. Demand charges reflect the capacity and transmission costs that are avoided at the utility system level, so these cannot be counted as additional societal benefits without risk of double-counting. However, from a customer-engagement perspective, these savings are key. Pepco DC's current General Service Primary Service rate structure has a demand charge of $6.46 per kW. A 1 MW battery behind the meter on this rate could reduce customer bills by about $70,000 per year, after accounting for the cost of energy losses in a cycling battery. In jurisdictions such as California that have both higher demand charges and state incentives, these savings alone can justify commercial customer storage deployment.

6. PORTFOLIOS FOR DEFERRAL

Deferring, and potentially avoiding, the Mt. Vernon Square Area Substation will be a multi-year and incremental process. Already, changing load growth trajectories have allowed Pepco to defer the projected in-service date for the substation by two years. Continued activities to keep the substation at least three years in the future might eventually allow the need to slip away entirely. We have developed portfolios of demand-side measures that would allow the substation to be deferred a year (to 2023), two years (to 2024) or indefinitely (past the 2026 end of Pepco's load forecast). These portfolios build on each other: the portfolio to defer two years looks like the combination of the two approaches capable of creating a one-year delay, while indefinite deferral starts with the two-year portfolio and then adds distributed generation and battery storage. Buying time with cost-effective energy efficiency and demand response also allows changes in the underlying drivers for load growth to mature, or fail to appear—all while pursuing actions that pay for themselves regardless of the deferral.

In estimating the costs of developing each of these NWA portfolios, we have accounted for total cost, regardless of who is paying that cost. For example, we have counted the full incremental cost of energy

[48] We are being conservative and not counting any avoided distribution system value, since that risks double-counting with the value of deferring the new substation.

efficiency, not just the cost of incentives and program administration. In calculating the non-deferral portion of the value created by each portfolio, we have included only the avoided energy, capacity, and transmission values, including avoided losses. These portfolios would be even more cost-effective if avoided externalities are included or if they avoid other distribution costs.

6.1. Defer for a year with efficiency or demand response

Deferring the substation to 2023 requires at least 2.2 MVA reduction in the 90/10 load forecast by 2022. 2.2 MVA is equivalent to about 2.1 MW of real power.[49] To provide a buffer, we have modeled portfolios that achieve 2.5 MW of real power peak reduction by 2022. Deferring the substation one year has a present value to ratepayers of $8.5 million.

Energy efficiency

We estimate that there is potential for 3.3 MW of incremental cost-effective energy efficiency in just the existing buildings in the SW Network Group. Additional energy efficiency in the new buildings that are creating the growing load (such as Capitol Crossing and whatever other buildings Pepco is basing its projection on) would increase the pool of potential measures and participants.

Incremental energy efficiency in the SW Network Group alone of 500 kW by 2019, 1.25 MW by 2020, 2 MW by 2021, and 2.5 MW by 2022 is achievable. (If new buildings with potential of at least 300 kW are not constructed, or the buildings are already maximally efficient, then the peak loads likely don't rise as fast as Pepco projects and the substation is deferred anyway.) The present value of the incremental cost of energy efficiency, including program administration, is $5.6 million, while that energy efficiency delivers $7.7 million in present value. Combined with the $8.5 million value from one year of deferral, this targeted energy efficiency delivers $16.2 million in benefit for $5.6 million in cost, for a net benefit to the District of $10.6 million.

Demand response

We estimate there is potential for 4.4 MW of demand response in just the existing buildings served by the SW Network Group. Harnessing 2.5 MW of this by 2022 is achievable. In addition, new buildings (such as Capitol Crossing) will also have demand response potential. (If they have proportional demand response potential and Pepco's load forecast is correct, there should be more than 6.5 MW of additional potential.)

Demand response participation starting at 500 kW in 2019, growing to 1.25 MW by 2020, 2 MW by 2021, and 2.5 MW by 2022 is achievable. We modeled demand response as costing $180/kW per year of participation, with costs ceasing when the new substation is built. This results in a total cost of $1.2

[49] For the calculation presented in this section we have assumed a 5 percent adjustment between a reduction in peak real power load at the end-use and a feeder-level MVA value. This reflects a 2 percent power factor adjustment, along with 3 percent assumed line losses that peak at times of highest demand.

million, returning $0.6 million in avoided capacity and transmission costs, in addition to the $8.5 million in substation deferral value. In total, then, $1.2 million in investment returns $9.1 million in benefits, for a net benefit of $7.9 million.

6.2. Defer for two years with efficiency and demand response

Deferring the new substation to 2024 requires at least 7.6 MVA reduction in the 90/10 load forecast by 2023 (corresponding to about 7.2 MW of real power reduction). Combining the efficiency and demand response portfolios just described would fall short of this level. However, if the efficiency acquisition were increased to 3 MW and demand response to 4.5 MW—such as by capturing the estimated full potential from existing buildings, or half the potential across all buildings—the need date could be deferred to 2024.

We modeled the portfolio of energy efficiency and demand response by year, shown in Table 27. This portfolio costs $9.3 million to implement (in present value) but returns $10.2 million in non-substation value in addition to $16.7 million in substation deferral value. Net benefits compared with building the substation in 2022 are therefore $17.5 million.

Table 27. Two-year deferral portfolio

Year	EE (MW)	DR (MW)
2019	0.5	1
2020	1.25	2
2021	2	3
2022	2.5	4
2023	3	4.5

6.3. Defer indefinitely with efficiency, demand response, PV, and storage

The two-year deferral portfolio acquires almost all of the available energy efficiency and demand response we expect to be present in the SW Network Group today. Deferring the substation to 2025 or later would require about another 5.5 MW of real power peak reductions. This can come from demand response and efficiency in new buildings, distributed generation, and battery storage. We modeled a portfolio that adds another 0.5 MW of energy efficiency (to 3.5 MW), 0.5 MW of demand response (to 5 MW), 1 MW of solar PV (modeled as contributing 0.25 MW to peak reduction), and 5 MW of battery storage (storing 28.1 MWh of energy). This portfolio, plus Pepco's projected loads, should keep the SW Network Group 90/10 peak below 49.5 MVA.

Table 28. Indefinite deferral portfolio

Year	EE (MW)	DR (MW)	PV (MW)	Storage (MW)
2019	0.5	1.0	-	-
2020	1.25	2.0	-	-
2021	2.0	3.0	-	-
2022	2.5	4.0	0.5	-
2023	3.0	4.5	1.0	2.5
2024	3.5	5.0	1.0	5.0
2025 and later	3.5	5.0	1.0	5.0

We modeled the battery storage as being a utility asset, on which Pepco would earn its rate of return; we believe this is among the more expensive options for how the battery service could be procured, from a ratepayer perspective. We have included the value of the battery for deferral, capacity, and avoided transmission costs, but not for any other services it may provide.

This portfolio has a present value cost of $36.5 million, and delivers $17.8 million in non-substation benefits. Deferral to 2024 or later is sufficient to bring this portfolio to a positive net value. With Pepco's current load forecast, however, this portfolio would be able to defer the substation indefinitely. If the station were deferred to 2030 by this portfolio, for example, it would provide a net benefit of $41.2 million. Permanent avoidance using this portfolio would have a present value of $211 million.

6.4. A path forward

The three portfolios we have described have increasing value to ratepayers as the substation can be deferred further into the future. We believe the following course of action would be advantageous to the District's ratepayers:

1) Confirm Pepco's load forecast for the SW Network Group and Substation #212 as a whole. Understand which buildings Pepco is assuming will be built, when, and what load they are forecast to create. As discussed in Section 3.6, Pepco's forecast is hard to believe based on the information we have in hand today. Understand alternatives to meet their load with Sub #212's radial network or from other substations.

2) If Pepco's forecast stands, begin aggressive customer engagement with the 17 existing buildings that drive the peak in the SW Network Group, as well as the developers of Capitol Crossing and any other identified new construction developers. Aim for the two-year deferral portfolio, with both demand response and energy efficiency. This engagement should include detailed peak reduction potential audits for each building to make specific what we have modeled here as generic. Identify whether any of these buildings have on-site backup generators that are EPA-approved for use in demand response.

3) If the two-year portfolio can be developed and demonstrated to be on track by 2021, revisit the options for on-site generation (such as PV) and storage, taking into account

current technology prices and policies, to determine if the substation can be entirely avoided or further cost-effectively deferred.

4) Continually update the load forecast based on changes in building schedules and specifications to avoid being caught out by earlier load growth, and to avoid unnecessary rush (e.g. too-early battery system purchase) if load is slower in materializing.

7. MEETING CUSTOMER NEEDS

7.1. Target markets

The buildings in the SW Network Group, and more generally served by the Northeast Substation #212, fall into four broad categories, each of which will require its own strategy to encourage participation in a push for a non-wires alternative. Those categories are:

1) Government buildings (e.g. GAO, Metro)
2) Office buildings
3) Multifamily residential buildings
4) Hotels

Some mixed-use buildings also have retail, and some buildings mix offices and residential.

Two of these categories (offices and multifamily) will exhibit landlord-tenant issues, while the other two (government and hotels) will not.

One thing that makes this potential NWA different from the Brooklyn-Queens Demand Management project or geotargeted energy efficiency projects in other jurisdictions is the small number of customers who all need to participate in order to achieve the substation deferral. In other NWA implementations, there have been large numbers of residential or small commercial customers, and programs have aimed to get participation from some fraction. Here nearly 100 percent participation may be required, but the short list of participants is also amenable to a customer-centric, account-management approach. So, while we can think of a hypothetical program as targeting “markets” in reality it is working with a particular set of fewer than 20 customers. We are restricted to thinking about markets at this point because the program has not yet identified and become acquainted with the particular buildings and the individuals who will make the relevant energy decisions about them.

7.2. Making participation compelling to building owners

This section identifies some of the messages or program approaches that we believe may be effective for the owners and operators of the fewer than 20 existing or under-construction buildings in the SW Network Group.

Financial incentives

In each deferral portfolio, the value of deferral alone (whether it is for one year, two years, or indefinitely) exceeds the full, all-parties cost of implementing the non-wires alternatives. This should mean that relatively generous incentives or cost-sharing are possible while maintaining program-level savings for ratepayers. Funding such incentives at least cost will require a funding source, akin to the source that funds the DC SEU, that does not come along with the costs of utility capital. It makes sense for this funding source to ultimately trace back to Pepco's ratepayers, since they are the ones who will save from the deferred or avoided substation. While generous incentives may be financially cost-effective, implementers should still try to maximize the cost-sharing from the participating buildings and customers. A performance contract structure, again akin to the DC SEU, may appropriately align incentives for the program administrator. For example, such a contract might share the savings from cost-conscious implementation with the administrator if the resources are acquired to stay on track to deferring the substation, and do nothing more than cover the administrator's costs if insufficient resources are acquired.

It will be difficult to walk away from potential savings in order to pressure a building owner to contribute more to an efficiency project, because nearly all customers need to participate in order for deferral to succeed. One path here could be to establish a minimum payback period, such as one year. Incentives could be used to bring down the cost of efficiency measures so that customers would see a one-year payback, but no further. Even a tenant who cannot be assured of remaining in a building past their current lease, or a building owner concerned about other opportunities for high returns on investment, may find a one-year payback difficult to reject.

Tenant services

Building owners are responsive to tenant needs, perhaps more so than they are responsive to messages regarding energy savings. Tenants increasingly desire "green" office space, with reduced energy bills and use of natural light.[50] Retrocommissioning should improve tenant comfort while simultaneously reducing energy bills. Residential tenants can be attracted to high-tech services like Wi-Fi thermostats and "smart home" features. Packaging the set of actions for each building in terms of their marketability to current and prospective tenants may therefore be effective.

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[50] Capitol Crossing, for example, advertises its LEED Platinum status, its green roof, and its role as an "Eco District" in its marketing materials.

Recognition

The reward for building owners and operators from public recognition can be significant. This recognition could take many forms, such as:

- Identifying the targeted area as an "Eco District" or other such moniker, with public signs and banners in the neighborhood identifying the targeted area, thanking participants, and providing a link to find out more and join the neighbors;
- Special events at which the Mayor or other leaders personally congratulate and thank building owners for their participation offer both press attention and access to policymakers;
- Invitations to participate in planning and design of future electric planning efforts;
- Trade press highlights of the tenant services that participants are now able to offer; and
- Insignia for the outside of buildings to highlight and associate leadership for neighbors, prospective tenants, and passersby.

Deferring or avoiding a new Mt. Vernon substation saves ratepayers money while simultaneously advancing energy efficiency and other distributed energy resources in the District. While further investigation is required to confirm that deferral is possible and to develop an action plan, it presents an opportunity for building owners, policymakers, regulators, and Pepco to demonstrate leadership and forward thinking.