Avoided Energy Costs in Maryland

Assessment of the Costs Avoided through
Energy Efficiency and Conservation Measures
in Maryland

Final Report

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1. Introduction

The Maryland General Assembly enacted the EmPOWER Maryland Energy Efficiency Act of 2008 (EmPOWER Maryland) calling for a 15 percent per capita reduction in electricity and peak demand from 2007 levels by the end of 2015. EmPOWER Maryland requires the State's four investor-owned electric utilities and the State's largest electric cooperative to fully comply with the reduction in peak demand and at least two-thirds (i.e., at least 10 percent) of the electricity reduction requirement. The State is responsible for the remaining electricity reductions through State-administered programs and revisions to the State's codes and standards. The Maryland Energy Administration (MEA) is responsible for implementing programs and monitoring the State's progress in meeting the statutory goals in electricity reduction. The Maryland Public Service Commission (PSC) oversees individual Maryland utility energy efficiency and conservation and demand response programs and assesses whether each program is feasible and cost-effective as a means of helping to achieve the EmPOWER Maryland goals, and also evaluates each utility program's impacts on electricity rates, jobs, and the environment.[1]

EmPOWER Maryland requires Maryland utilities to submit plans for achieving EmPOWER Maryland targets for the next three years on or before September 1, 2014, to the Maryland PSC. EmPOWER Maryland also authorizes MEA, in coordination with the Maryland PSC, to consider whether electricity and peak demand reduction targets should be set beyond 2015 and the feasibility of setting energy reduction targets for natural gas companies. MEA issued a report to the Senate Finance Committee and the House Economic Matters Committee. The report recommended, among other things, that the avoided cost of saving a MWh of electricity, a MW of capacity and a MMBtu of natural gas be determined; that a cost effectiveness test be established and used in evaluating energy efficiency programs; and that new targets be set for annual energy and demand savings for 2015 through 2017.[2] In July 2013, MEA filed a proposal with the Maryland PSC related to planning for EmPOWER Maryland after 2015. The recommendations in MEA's proposal parallel the recommendations it made to the Maryland General Assembly.

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[1] The EmPOWER Maryland program was established through the EmPOWER Maryland Energy Efficiency Act of 2008. See Chapter 7-211 of the Public Utilities Article, *Annotated Code of Maryland*.
[2] Maryland Energy Administration, *Report to the Senate Finance Committee and House Economic Matters Committee to Discuss Whether to Modify EmPOWER Maryland Targets Beyond 2015*, March 18, 2013, http://energy.maryland.gov/empower3/documents/EmPOWERPlanningFinalReport2013-01-16.pdf.

2. Methodology and Approach

This report, sponsored by the Power Plant Research Program (PPRP) of the Maryland Department of Natural Resources and the MEA, provides a set of estimates of the avoided costs associated with electric energy efficiency and conservation in Maryland implemented through the State's EmPOWER Maryland initiative. The methodology and approach of the analysis was discussed with a broad range of stakeholders, including environmental groups, Maryland electric distribution utilities, representatives of Maryland State government agencies, and competitive electric power providers operating in Maryland.

Total avoided costs are segmented into eight categories, each of which is separately addressed in this report. The categories are as follows:

1. Avoided electric energy costs;
2. Avoided electric capacity costs;
3. Avoided costs of renewable energy certificates (RECs);
4. Avoided electric transmission and distribution costs;
5. Demand reduction induced price effects (DRIPE);
6. Avoided natural gas costs;
7. Avoided costs of other fuels (fuel oil and propane); and
8. Avoided water and wastewater costs.

Environmental compliance costs associated with reduced energy consumption do not represent a separate cost category since they are reflected in the avoided electric energy cost component. The avoided cost of environmental compliance for electric generation in Maryland, however, has been separately estimated and is provided in an appendix to this report. Additionally, estimated reductions in NOx, $SO_{2,}$ and carbon dioxide (CO_2) from Maryland power plants and PJM as a whole are also provided in this appendix.

The avoided cost estimates of each category are disaggregated into each of the four major investor-owned utilities in Maryland, where appropriate and data availability permitted. Avoided cost estimates were not prepared for municipal electric utilities and rural electric cooperatives. Southern Maryland Electric Cooperative (SMECO) is included in Pepco's estimate. Avoided cost estimates were also broken down by customer class (residential, commercial and industrial), again where appropriate and data availability allowed.

Current federal and state policies are assumed to remain in effect, with the exception of the federal production tax credit (PTC) for most renewable energy technologies, which expired at the end of 2013.[3] No changes to the Maryland Renewable Energy Portfolio Standard (RPS) or to other state RPS policies were assumed. Full compliance with the non-solar renewable energy requirement for both Tier 1 and Tier 2 of the Maryland RPS is assumed; also assumed is 50 percent compliance with the solar set-aside by 2020. The U.S. Environmental Protection Agency (EPA) has proposed CO_2 emission limits for new power plants, but a final rule has not been issued as of this writing. Environmental externality costs were also not factored into the avoided cost estimates.

The Long-Term Electricity Report (LTER) Reference Case Update (RCU),[4] published by PPRP in May 2013, was relied upon to the extent possible, both for ease of analysis and also to ensure consistency between the LTER RCU and the avoided cost report. The Ventyx Integrated Power Model (IPM) was relied upon and the avoided cost analysis incorporates Ventyx's Fall 2012 Reference Case projections. Ventyx re-ran its model to incorporate more recent available data, including the results of the 2013 PJM capacity auction, and the lowering of the Regional Greenhouse Gas Initiative (RGGI) allowance cap by 45 percent. Both the 2011 LTER[5] and the RCU provide a detailed description of the Ventyx model in Chapter 2.

Developed by ABB/Ventyx, IPM is a set of models designed to reflect the market factors affecting power prices, emissions, generation, power plant development (and retirements), fuel choice, and other power market characteristics. The IPM contains a detailed database that includes current generation capacity in the U.S., including capacity, heat rate, fixed operation and maintenance (O&M) costs, variable O&M costs, fuel costs, and emissions rates. Ventyx also incorporates information regarding the transmission transfer capabilities within the market areas, or "zones", that Ventyx uses to model the Eastern U.S. Ventyx uses zonal energy and peak demand forecasts and its production cost model to meet the zonal load requirement through within-zone generation capacity and transfers across zones. Generation units are dispatched on a least-cost basis to meet load and energy flows across zones up to the constraints of inter-zonal transmission capacity.

IPM also estimates capacity prices based on a make-whole payment concept whereby marginal generators either delay retirement or a new generator enters and capacity prices are set such that the revenues the generator earns in the energy and capacity markets cover its total costs.

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[3] In 2012, the U.S. Congress amended the PTC to allow renewable energy projects to take the PTC after 2013 if certain eligibility requirements regarding capital investment or project construction are met by the end of 2013. No effort was made to distinguish which planned renewable energy projects would meet that deadline and which would not.

[4] Maryland Department of Natural Resources, Power Plant Research Program, *Long-term Electricity Report for Maryland: Reference Case Update*, May 2013, http://esm.versar.com/pprp/pprac/Docs/LTER_RCU_FINAL.pdf.

[5] Maryland Department of Natural Resources, Power Plant Research Program, *Long-term Electricity Report for Maryland*, December 1, 2011, http://esm.versar.com/pprp/pprac/Longterm_Electricity_Report/Final/LTER%20Final%20Report.pdf.

The Ventyx model allows for imports and exports of energy among zones and the model constructs new generic power plants based on least-cost assumptions to meet load not met by the existing stock of generation resources. Maryland has historically been a large importer of energy and has imported approximately 30 to 40 percent of its energy requirements in recent years. Maryland is also a relatively high-priced zone for power plant construction compared to some of the other PJM zones. Power plant variable operating costs in Maryland are also higher than in most other PJM states since Maryland and Delaware are the only states within PJM that are a party to RGGI. These considerations affect the location and timing of new power plant construction in the Ventyx model.

PJM is represented in the Ventyx model as having 10 zones, as indicated in Table 1. Because this report is focused on Maryland, only the zones in the Ventyx model that contain Maryland utilities are examined. These are bolded in Table 1, below. The zones assessed in this report include PJM-APS, PJM-MidE, and PJM-SW. Because some of the zones include utilities that serve customers outside of Maryland, or utilities with multi-state service territories, the results were adjusted to reflect only the electric demand of Maryland customers.

Table 1. PJM Zones in the Ventyx Model

Zone	Utility Territories Covered
PJM-AEP	American Electric Power, Dayton Power & Light
PJM-APS	**Allegheny Power Systems**
PJM-ATSI	FirstEnergy American Transmission Systems
PJM-CE	Commonwealth Edison
PJM-DEOK	Duke Energy Kentucky, Duke Energy Ohio, East Kentucky Power Cooperative
PJM-S	Virginia Power Company
PJM-MidE	**Atlantic Electric, Delmarva Power & Light (DPL), Jersey Central Power & Light, PECO Energy, Public Service Electric & Gas, Rockland Electric**
PJM-EPA	Metropolitan Edison, Pennsylvania Power & Light, UGI Corporation
PJM-SW	**Baltimore Gas & Electric (BGE) and Potomac Electric Power Company (Pepco)**
PJM-WPA	Pennsylvania Electric

The methodology and assumptions for determining each individual avoided cost element is explained in subsequent chapters. The remainder of this chapter will discuss the overall assumptions and methodologies used in the report.

Load growth: The PJM load growth forecast prepared in December 2012 is used, modified to include the effects of state energy efficiency and conservation programs, and the projected impact of plug-in electric vehicles. For Maryland, the first three years of realized energy and demand reductions (2010 through 2012) are incorporated into the model, followed by projected reductions through 2015. Reduction in energy and demand from energy efficiency programs in other PJM states are also incorporated, with actual data incorporated for the past two years (2011 and 2012).

Projected demand from demand response and advanced metering initiatives (AMI) are also included. Demand response estimates are based on what was bid into PJM's Reliability Pricing Model (RPM) Base Residual Auctions covering the period through May 2017, then held flat afterwards. AMI projections are developed by Ventyx. The Ventyx model treats both demand response and AMI as dispatchable supply-side resources that are included in the supply stack and, therefore, though both ultimately serve to reduce demand, they are not treated as adjustments to the load forecast.

Electric Energy Prices: The avoided costs of electricity prices are primarily from the Ventyx model, except for 2013 and 2014. Market settlements in PJM are used for 2013, while a blend of commodity prices from the NYMEX futures market and Ventyx modeling results are relied upon for 2014. The results are described in Chapter 3. Electricity prices are further adjusted to reflect retail prices and to incorporate marginal distribution losses, as explained below.

Line Losses: Energy efficiency measures help to avoid transmission and distribution (T&D) line losses. Transmission line losses are a part of locational marginal prices (LMPs) and are, therefore, reflected in electricity prices. A multiplier was applied to electricity prices to incorporate distribution line losses. Chapter 3 provides greater detail on the methodology and assumptions.

Electric Generating Capacity Prices: Prices from PJM's RPM capacity auction are used for the current year (2013) and for the next three delivery years through May 2017, since the RPM is a forward capacity market. After 2017, average historical capacity market prices are inflated using the Handy-Whitman Index. The avoided cost of electric generation capacity is also only applicable for energy efficiency that reduces demand during on-peak hours; demand reductions during off-peak hours will result in avoided energy costs only, not avoided capacity costs. Capacity prices are further adjusted to reflect two additional assumptions for this report. During on-peak hours, an avoided MW of capacity from energy efficiency is equivalent to more than one MW of actual capacity, accounting for PJM's reserve requirements and marginal T&D losses. Consequently, capacity prices are first increased by PJM's reserve margin requirement and then increased again to reflect marginal T&D losses. Chapter 4 provides additional information on the methodology and assumptions that were used.

Capital and Operating Costs of Renewable Energy Generation Plants: The assumptions for renewable energy generation in this report are focused on land-based wind and solar. These technologies are assumed to be the marginal renewable energy technologies for meeting the solar and Tier 1 non-solar requirements of the Maryland RPS. Capital cost data are drawn from several publications and correspondence with state and federal agencies and representatives of the solar industry. Fixed O&M costs are from EIA's Annual Energy Outlook 2013; variable costs for wind and solar are assumed to be zero. The capital costs of solar have decreased significantly in recent years, but considerable uncertainty exists as to whether these rapid declines in capital costs will continue. The capital costs of land-based wind, while historically volatile, are projected by several estimates to decrease at a steady rate over time. Chapter 5 describes the assumptions and methodologies for renewable energy generation.

Renewable Energy Certificate Prices: Renewable energy certificate (REC) prices were derived by estimating the REC revenue needed to support a 200-MW wind project and a 10-MW utility-scale solar project to comply with the Tier 1 non-solar and solar requirements of the Maryland RPS, respectively. A "make whole" methodology (also referred to as a "gap analysis" approach) was used to determine the REC price necessary to make a wind or solar project economic after accounting for: (1) the capital cost of the project; (2) the cost of capital; (3) O&M expenses; (4) taxes; (5) revenue obtained from the sale of energy and capacity; and (6) the federal investment tax credit (for solar only). Solar REC prices are capped at $50 per REC in the later years of the analysis period, as modeled solar REC prices are higher than the $50 Maryland Solar Alternative Compliance Payment. The Ventyx model adds new wind and solar facilities annually to meet the higher RPS requirements. More information on the modeling assumptions and methodology are provided in Chapter 5.

Electric T&D Capacity: The avoided T&D cost estimates represent deferred or reduced investments in electric T&D capacity due to energy efficiency or demand response. Estimates included in this report are based on utility-provided data. Chapter 6 includes more information on the assumptions and methodology.

Natural Gas, Propane and Distillate Fuel Oil Assumptions: For natural gas, NYMEX futures prices at Henry Hub (HH) are used for 2014 through 2016, followed by projections from the Ventyx Fall 2012 Reference Case. Natural gas T&D costs are projected using historical Maryland prices and growth rates derived from the AEO 2013's MidAtlantic Reference Case. Chapter 8 describes the methodology in more detail. Projections from AEO 2013 were used for propane and distillate fuel oil, as documented in Chapter 9.

Water and Wastewater: Average residential customer usage of water and wastewater was provided by Baltimore City's Department of Public Works. For commercial and industrial customers, a review of average water use levels for these customer sectors at non-Maryland water utilities was conducted. An assumed growth rate was applied based on a biannual survey of water and wastewater rates at over 200 utilities. Chapter 10 includes more information on the methodology, assumptions, and the avoided cost results.

Environmental Assumptions: The avoided costs of emissions compliance are not provided in this report because they are incorporated into avoided energy costs. The marginal emissions reductions from energy efficiency are based on Ventyx model runs in which small reductions in load are applied to each PJM zone. More information and the results are available in Appendix 1.

Inflation: Prices in this report are presented in real terms, in 2012 dollars. Appendix 2 presents all of the avoided cost estimates in nominal dollars. Inflation rate assumptions are based on consensus projections for the U.S. Gross Domestic Product Chained Price Index.[6]

This report is organized as follows: The following eight chapters (Chapter 3 through 10) discuss the methodologies, assumptions, and the results for avoided electric energy costs; avoided capacity costs; avoided RECs; avoided T&D costs; the demand reduction induced price effects (DRIPE); avoided natural gas costs; avoided propane and distillate fuel oil costs; and avoided water and wastewater costs. An appendix of emissions allowance prices and marginal emissions reductions from energy efficiency is included, as is an appendix showing nominal prices for each avoided cost element by utility and customer class.

[6] Walters Kluwer, *Blue Chip Economic Indicators* (Vol. 38, No. 10), October 10, 2013.

3. Electric Energy

3.1 Electricity Prices

The avoided costs associated with electric energy are primarily based on forecasted annual electricity prices in Maryland. Electricity prices are differentiated into summer and non-summer seasons, on- and off-peak periods, and vary by region. The summer season is defined as the months of June through September; the non-summer season includes all other months. The on-peak and off-peak periods correspond to the PJM on-peak and off-peak period definitions. The on-peak period includes non-holiday weekdays between 7:00 a.m. and 11:00 p.m. All other hours are off-peak. The regional prices correspond to the three transmission zones in Maryland as defined by the topology in the Ventyx model. The electricity prices in Central Maryland (i.e., PJM-SW) are applicable to BGE, Pepco, and SMECO. The electricity prices for the Delmarva Peninsula (i.e., PJM-MidE) correspond to DPL, and the electricity prices in Western Maryland (i.e., PJM-APS) correspond to Potomac Edison.

The 2013 electricity prices reflect actual market settlements in PJM. Electricity prices in 2014 are based on a blend of commodity prices in the NYMEX futures market and the Ventyx modeling results. The remaining years are based only on Ventyx modeling results. The electricity price forecast is presented graphically in Figure 1 and shown in Table 2 and Table 3, below. This forecast reflects energy-only prices delivered to the relevant transmission zone, and, therefore, can be viewed as zonal LMPs.

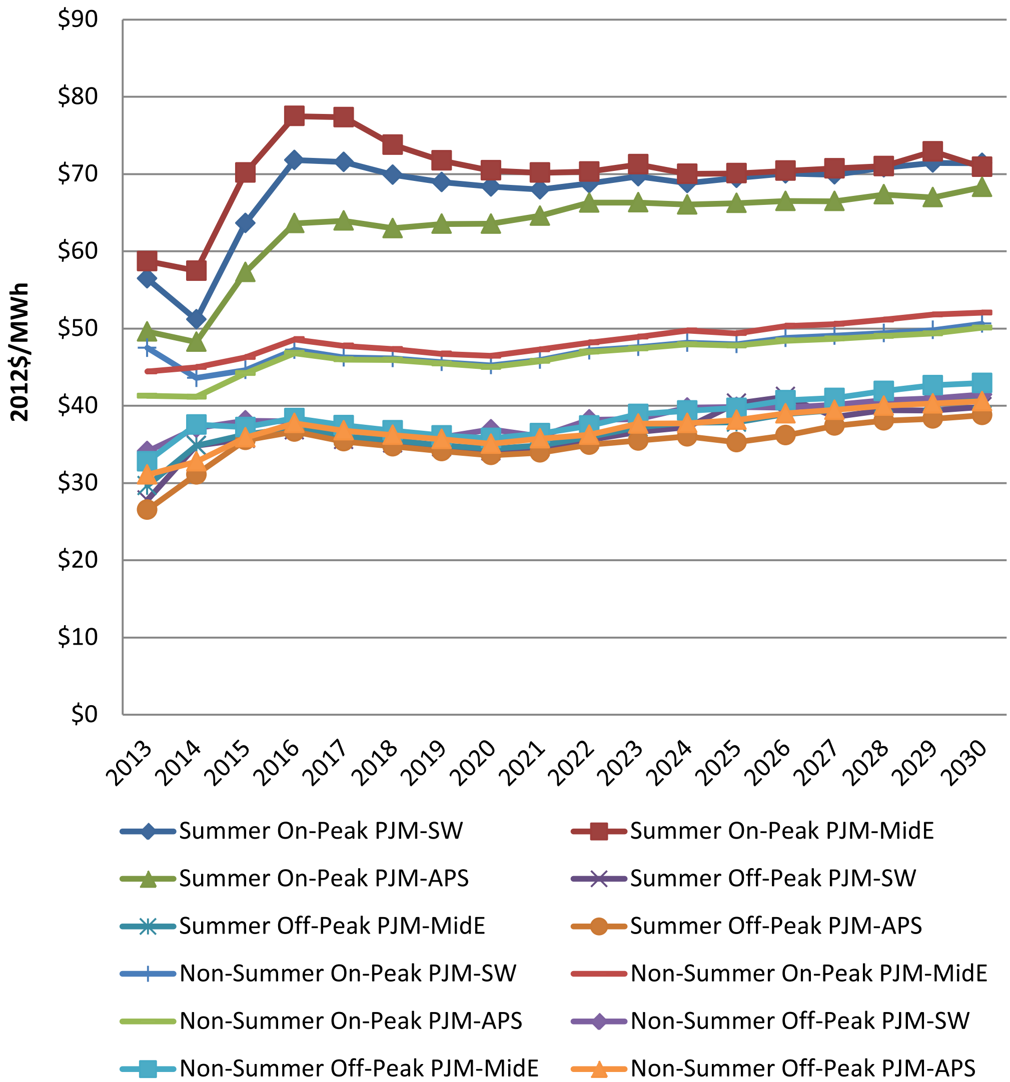
Table 2. Summer Electricity Price Forecast (2012$/MWh)

	On-Peak			Off-Peak		
Year	PJM-SW	PJM-MidE	PJM-APS	PJM-SW	PJM-MidE	PJM-APS
2013	$56.45	$58.70	$49.59	$27.78	$29.64	$26.51
2014	51.15	57.47	48.25	34.83	34.82	31.09
2015	63.62	70.16	57.29	35.72	36.27	35.54
2016	71.79	77.49	63.61	36.82	37.16	36.63
2017	71.54	77.34	63.94	35.59	36.01	35.38
2018	69.90	73.78	62.97	35.13	35.53	34.74
2019	68.93	71.72	63.53	34.65	34.85	34.12
2020	68.36	70.44	63.56	34.11	34.42	33.60
2021	67.98	70.15	64.59	34.59	34.87	33.93
2022	68.77	70.30	66.29	35.55	35.95	34.93
2023	69.68	71.24	66.31	36.61	37.22	35.47
2024	68.80	70.01	66.03	37.22	37.80	36.02
2025	69.46	70.08	66.23	40.30	37.84	35.27
2026	70.06	70.41	66.49	41.16	38.94	36.17
2027	69.91	70.72	66.48	38.56	39.44	37.41
2028	70.82	71.00	67.35	39.43	40.38	38.07
2029	71.45	72.91	66.97	39.38	40.63	38.33
2030	71.41	70.91	68.29	39.84	40.90	38.78

Table 3. Non-Summer Electricity Price Forecast (2012$/MWh)

	On-Peak			Off-Peak		
Year	PJM-SW	PJM-MidE	PJM-APS	PJM-SW	PJM-MidE	PJM-APS
2013	$47.49	$44.42	$41.27	$34.08	$32.79	$31.07
2014	43.60	44.98	41.15	37.11	37.56	32.78
2015	44.61	46.26	44.20	38.06	37.22	35.88
2016	47.23	48.58	46.80	37.99	38.38	37.73
2017	46.26	47.76	45.98	37.01	37.47	36.79
2018	46.14	47.33	45.94	36.41	36.79	36.20
2019	45.65	46.72	45.46	35.92	36.13	35.66
2020	45.22	46.46	45.00	36.92	35.80	35.07
2021	45.94	47.28	45.78	36.01	36.41	35.74
2022	47.15	48.17	46.97	38.18	37.41	36.23
2023	47.59	48.92	47.41	38.26	38.91	37.68
2024	48.15	49.73	47.94	39.74	39.35	37.74
2025	47.95	49.37	47.77	39.83	39.70	38.15
2026	48.77	50.31	48.43	39.76	40.69	38.99
2027	49.06	50.57	48.67	40.11	40.99	39.45
2028	49.40	51.12	49.02	40.69	41.90	39.99
2029	49.78	51.79	49.36	40.97	42.64	40.28
2030	50.62	52.04	50.09	41.44	42.94	40.57

Figure 1. Maryland Electricity Price Forecast (2012$/MWh)



Two adjustments were made to the electricity price forecast to convert the data into avoided electric energy costs. One adjustment entails a gross-up for avoided line losses, as explained below. Additionally, the data shown in Table 2 and Table 3 are the equivalent of wholesale electricity market prices. In order to be characterized as an avoided cost to the retail consumer, these data should reflect retail market prices rather than wholesale LMPs. To convert wholesale power supply to retail power supply, $0.007 per kWh (7 mills) in real 2012 dollars is added to each of the avoided kWh associated with implementation of energy conservation and efficiency projects. This amount reflects the cost of ancillary services and PJM avoidable charges, compensation for business risk, and retail supplier margin. The wholesale-to-retail adder does not vary by electric distribution company service area or customer class.

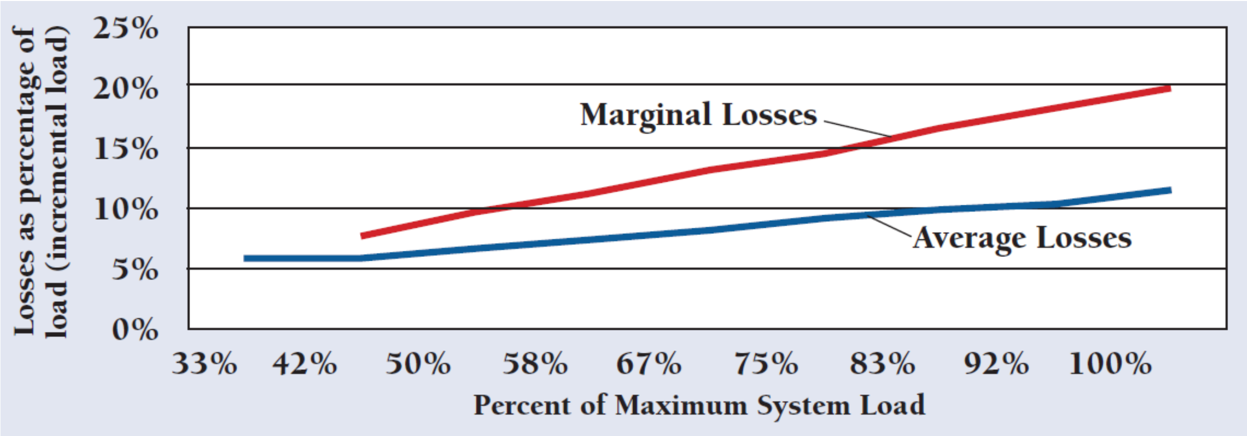
The 7-mill wholesale-to-retail adder was estimated based on review of avoidable PJM charges contained in PJM's Open Access Transmission Tariff and review of confidential contract documents put in place over the past three years related to the provision of retail electric power in the PJM area as well as the Midcontinent Independent System Operator (MISO) area. There is some degree of uncertainty associated with the $0.007 per kWh value since the confidential contract vehicles reviewed included different provisions for the pass-through of cost elements and also included differences in the incurrence of risk and sharing of risk between seller and buyer. We also note that the adder does not include taxes and certain surcharges that are included in retail billings (e.g., the Environmental Surcharge, the Gross Receipts Tax, the EmPOWER Maryland surcharge).

3.2 Line Losses

In addition to the avoided cost of electricity, energy efficiency measures provide a benefit in the form of marginal reductions to T&D line losses. Transmission line losses are a component of LMPs, thus the avoided electric energy costs associated with transmission line losses are embedded in the electricity price forecast.

Distribution line losses vary by utility depending on the characteristics of their distribution system infrastructure (e.g., line distance, system density, voltage levels). The calculation of avoided distribution line losses is based on marginal losses rather than average losses because losses grow exponentially with the amount of load being carried. As shown below in Figure 2, marginal distribution losses are consistently higher than average distribution losses at the same point on a utility's load curve.

Figure 2. Average and Marginal Losses



Source: Jim Lazar and Xavier Baldwin, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*, the Regulatory Assistance Project, August 2011. Assumes 7 percent average losses; losses are assumed to be 25 percent no-load losses, and 75 percent resistive losses.

Based on a 2011 research paper published by the Regulatory Assistance Project, it is assumed that marginal distribution losses are 1.5 times average distribution line losses.[7] Average distribution system losses for each utility are available in annual Federal Energy Regulatory Commission (FERC) Form No. 1 filings. Exeter utilized the most recent three years (2010-2012) of FERC Form No. 1 data from each utility. Marginal distribution line loss estimates are presented in Table 4, below.

Table 4. Distribution Line Losses

Utility	Average Distribution Losses (2010-2012)	Marginal Distribution Line Loss Rate
BGE	6.5%	9.8%
DPL	5.5	8.2
Pepco/SMECO	5.0	7.5
Potomac Edison*	4.5	6.8
Average	5.4	8.1
*There appeared to be an error in Potomac Edison's 2011 FERC Form No. 1 data, so Exeter utilized 2009 data in place of 2011.		

Source: 2010-2012 FERC Form 1 filings, page 401a.

[7] Jim Lazar and Xavier Baldwin, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*, the Regulatory Assistance Project, August 2011.

3.3 Avoided Cost of Electric Energy

Applying marginal distribution system losses to the electricity price forecast (adjusted to reflect retail market prices) results in the avoided electric energy cost estimates provided below in Table 5 and Table 6, and shown graphically in Figure 3 and Figure 4. Avoided electric energy costs are presented, in 2012 dollars per megawatt-hour ($/MWh).

Table 5. Avoided Electric Energy Costs during Summer Months (2012$/MWh)

	On-Peak				Off-Peak			
Year	BGE	Pepco/ SMECO	DPL	Potomac Edison	BGE	Pepco/ SMECO	DPL	Potomac Edison
2013	$68.21	$69.66	$71.09	$60.42	$37.39	$38.18	$39.65	$35.77
2014	62.51	63.83	69.76	58.98	44.96	45.92	45.25	40.67
2015	75.91	77.53	83.49	68.63	45.92	46.89	46.82	45.41
2016	84.70	86.50	91.43	75.37	47.11	48.11	47.79	46.58
2017	84.42	86.22	91.26	75.73	45.78	46.75	46.54	45.24
2018	82.66	84.42	87.41	74.69	45.29	46.25	46.02	44.56
2019	81.62	83.35	85.19	75.30	44.77	45.72	45.29	43.89
2020	81.01	82.73	83.80	75.32	44.19	45.13	44.82	43.34
2021	80.60	82.31	83.48	76.42	44.70	45.65	45.31	43.69
2022	81.44	83.17	83.64	78.24	45.74	46.71	46.48	44.76
2023	82.43	84.18	84.66	78.26	46.88	47.88	47.85	45.34
2024	81.49	83.22	83.33	77.96	47.54	48.55	48.48	45.92
2025	82.19	83.94	83.41	78.17	50.85	51.93	48.52	45.12
2026	82.84	84.60	83.77	78.45	51.77	52.87	49.72	46.09
2027	82.67	84.43	84.10	78.44	48.98	50.02	50.25	47.41
2028	83.66	85.43	84.40	79.37	49.91	50.97	51.26	48.11
2029	84.33	86.12	86.47	78.96	49.85	50.91	51.54	48.39
2030	84.28	86.07	84.30	80.38	50.35	51.42	51.83	48.87

Figure 3. Avoided Electric Energy Costs during Summer Months (2012$/MWh)

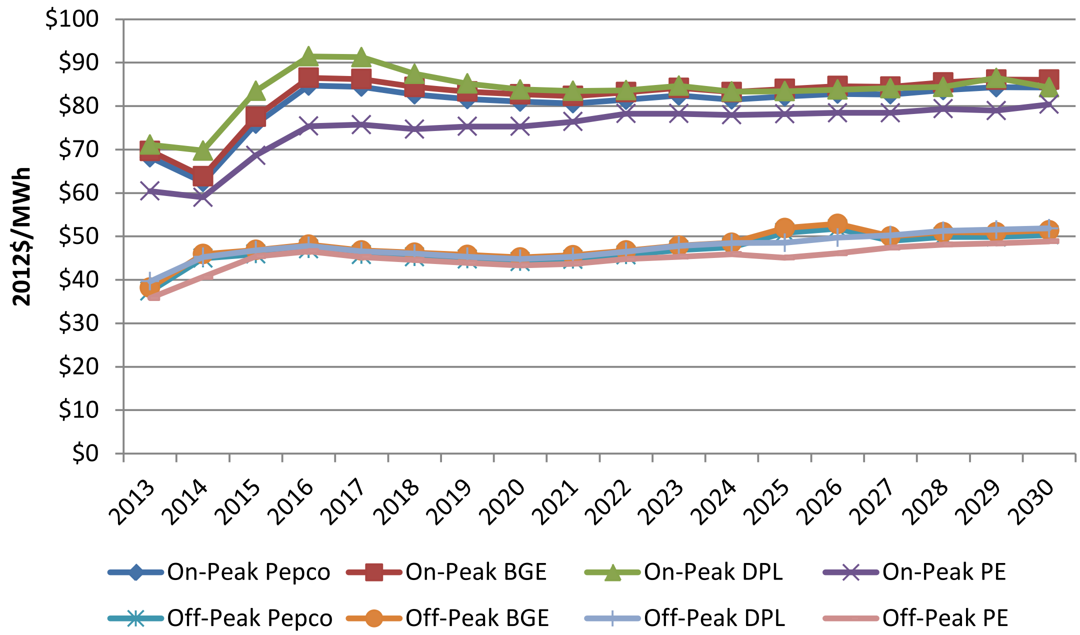


Figure 4. Avoided Electric Energy Costs during Non-Summer Months (2012$/MWh)

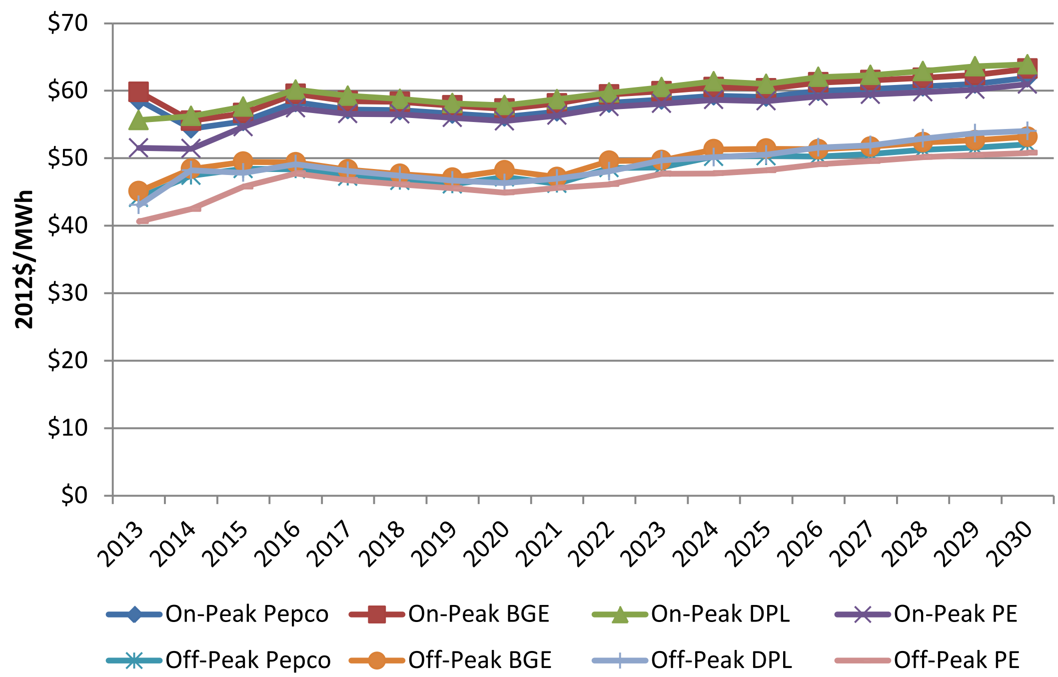


Table 6. Avoided Electric Energy Costs during Non-Summer Months (2012$/MWh)

	On-Peak				Off-Peak			
Year	BGE	Pepco/ SMECO	DPL	Potomac Edison	BGE	Pepco/ SMECO	DPL	Potomac Edison
2013	$58.58	$59.82	$55.64	$51.53	$44.16	$45.10	$43.05	$40.64
2014	54.40	55.55	56.25	51.40	47.42	48.42	48.21	42.46
2015	55.48	56.66	57.63	54.66	48.44	49.47	47.85	45.78
2016	58.30	59.54	60.14	57.43	48.37	49.39	49.11	47.75
2017	57.25	58.46	59.26	56.56	47.31	48.31	48.12	46.75
2018	57.13	58.34	58.79	56.51	46.66	47.65	47.39	46.12
2019	56.60	57.80	58.13	56.00	46.13	47.11	46.67	45.54
2020	56.13	57.33	57.84	55.51	47.21	48.21	46.31	44.91
2021	56.90	58.11	58.73	56.34	46.24	47.22	46.97	45.63
2022	58.21	59.45	59.70	57.61	48.57	49.60	48.06	46.14
2023	58.68	59.92	60.51	58.08	48.65	49.69	49.68	47.70
2024	59.28	60.54	61.38	58.65	50.24	51.31	50.15	47.76
2025	59.07	60.33	61.00	58.47	50.34	51.41	50.53	48.20
2026	59.95	61.23	62.02	59.17	50.26	51.33	51.60	49.09
2027	60.27	61.55	62.30	59.43	50.64	51.72	51.93	49.58
2028	60.63	61.91	62.89	59.80	51.26	52.35	52.92	50.17
2029	61.04	62.33	63.62	60.17	51.56	52.66	53.71	50.48
2030	61.93	63.25	63.89	60.95	52.07	53.18	54.04	50.79

4. Electric Generating Capacity

4.1 Capacity Prices

The avoided costs associated with electric generating capacity are based on PJM's RPM Base Residual Auction (BRA). As the RPM is a forward capacity market, actual capacity prices are known for the current delivery year as well as the next three delivery years. In PJM, a delivery year runs from June through May (e.g., the current delivery year is June 1, 2013 through May 31, 2014). Thus, actual capacity market prices are already set through May 2017.

We note that it was Exeter's original intent to utilize the Ventyx modeling results as the basis for calculating the avoided cost of electric generating capacity beyond May 2017. However, during stakeholder meetings to review the draft of this report, concerns were expressed that Ventyx's modeled capacity prices were unreasonably high. As such, at the direction of MEA, the Ventyx modeling output was replaced with the methodology described below in favor of achieving consensus among the stakeholders.

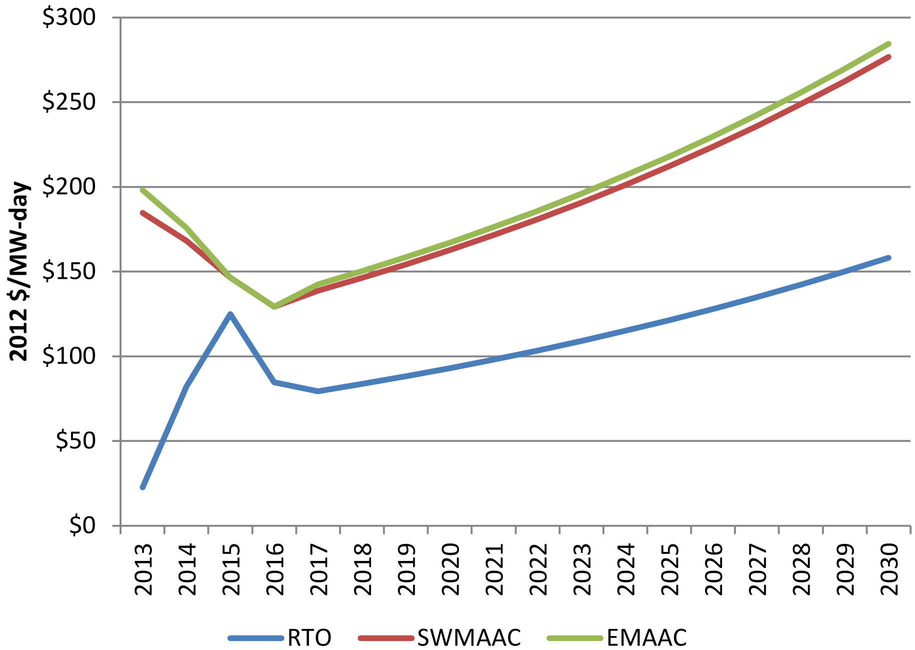
Consistent with the electricity price forecast, there are different capacity prices for the three Ventyx transmission zones in Maryland: PJM-SW, PJM-MidE, and PJM-APS. The capacity prices in the SWMAAC region of PJM correspond to the PJM-SW transmission zone. Similarly, the EMAAC region of PJM corresponds to the PJM-MidE transmission zone, and the RTO capacity prices are used for the PJM-APS transmission zone.

For the purposes of the avoided cost analysis, the delivery year capacity prices were converted to annual values through 2016. The average nominal value of capacity prices from the 2010/11 delivery year through the 2016/17 delivery year is used to represent the value of capacity in 2017 for each zone. This value is then escalated annually at a rate of 7.7 percent to provide nominal capacity prices through 2030. The 7.7 percent figure is based on a five-year average compounded annual growth rate of the Handy-Whitman Index for the North Atlantic Region for "Total Other Production Plant." This index is what PJM uses to escalate the Cost of New Entry (CONE) when developing the Variable Resource Requirement (VRR) curve for each BRA.[8]

The resulting capacity price forecast is presented graphically in Figure 5 in 2012 dollars per MW-day. As described in the next section, two adjustments are necessary to convert capacity prices into the avoided cost of electric generating capacity.

[8] The VRR curve is an administratively determined demand curve (demand for capacity) and the CONE represents a point on the VRR curve.

Figure 5. Capacity Price Forecast (2012$/MW-day)



4.2 Avoided Cost of Electric Generating Capacity

Because one MW of avoided capacity for an end-user is equivalent to more than one MW of avoided generation capacity, two adjustments are made to convert capacity prices into the avoided cost of electric generating capacity. First, capacity prices are increased by approximately 9 percent to account for PJM's unforced capacity (UCAP) reserve margin requirement for electric generating capacity.[9] In addition, another 14.25 percent is added to account for marginal T&D line losses that are avoided at the end-user level. Estimated T&D line losses are based on historical data from the EIA State Electricity Profile for Maryland.[10] Between 1990 and 2010, average T&D losses in Maryland were approximately 9.5 percent, which compares to the national average of about 7 percent. Marginal T&D losses in Maryland are estimated at 14.25 percent based on the assumption described in the avoided energy cost section, i.e., marginal losses are assumed to equal 1.5 times average losses. Based on these two adjustments, the estimated avoided costs of electric generating capacity are provided below in Table 7 in 2012 dollars per megawatt-day (2012$/MW-day).

[9] The UCAP reliability requirement in the 2016/17 BRA was approximately 9 percent of PJM's forecast peak load.
[10] U.S. Energy Information Administration, *Maryland Electricity Profile 2010*, Table 10: Supply and Disposition of Electricity, 1990 through 2010, released January 30, 2012, http://www.eia.gov/electricity/state/maryland/.

Table 7. Avoided Electric Generating Capacity Costs (2012$/MW-day)

Year	Pepco/BGE/ SMECO	DPL	Potomac Edison
2013	$229.81	$246.54	$28.23
2014	209.33	218.78	102.40
2015	182.27	182.27	155.46
2016	160.86	160.86	105.45
2017	172.63	177.38	98.69
2018	182.06	187.07	104.08
2019	192.00	197.29	109.76
2020	202.48	208.06	115.76
2021	213.54	219.42	122.08
2022	225.20	231.40	128.75
2023	237.50	244.04	135.78
2024	250.47	257.37	143.19
2025	264.15	271.42	151.01
2026	278.58	286.25	159.26
2027	293.79	301.88	167.96
2028	309.83	318.36	177.13
2029	326.75	335.75	186.80
2030	344.60	354.08	197.00

5. Avoided Renewable Energy Costs

Energy efficiency and conservation measures provide a benefit in the form of avoided renewable energy costs because under Maryland's RPS, renewable energy compliance requirements are reduced in proportion to energy consumption. That is, when one MWh of electric energy consumption is avoided, the amount of renewable energy (Solar, Tier 1, and Tier 2) required to satisfy the Maryland RPS is reduced in proportion to the percentage required for that year. Table 8 below shows the renewable energy percentage requirement by year established by Maryland's RPS.

Table 8. Maryland RPS Requirements

Year	Solar	Tier I	Tier II
2013	0.25%	7.95%	2.5%
2014	0.35	9.95	2.5
2015	0.50	10.00	2.5
2016	0.70	12.00	2.5
2017	0.95	12.15	2.5
2018	1.40	14.40	2.5
2019	1.75	15.65	--
2020	2.00	16.00	--
2021	2.00	16.70	--
2022	2.00	18.00	--
2023	2.00	18.00	--
2024	2.00	18.00	--
2025	2.00	18.00	--
2026	2.00	18.00	--
2027	2.00	18.00	--
2028	2.00	18.00	--
2029	2.00	18.00	--
2030	2.00	18.00	--

5.1 Renewable Energy Credit Prices

Avoided renewable energy requirements result in cost savings that are estimated by projecting REC prices. Separate REC prices exist for Maryland Tier 1 RECs, Maryland Tier 2 RECs, and Maryland Solar RECs. REC prices represent the costs associated with the renewable energy attributes of one MWh of renewable energy. In the near-term, REC prices relied upon in this analysis are based on the futures market for Maryland RECs. In the long-term, Solar REC prices and Tier I REC prices are estimated through modeling, as explained in further detail in subsequent sections of this chapter. Tier II REC prices are held constant at current levels through the end of 2018, when the Tier II requirement terminates. Exeter's REC price projections are presented in Table 9, below.

Table 9. Renewable Energy Credit Price Projections

	Nominal$/REC			2012$/REC		
Year	**Solar**	**Tier I**	**Tier II**	**Solar**	**Tier I**	**Tier II**
2013	$135	$14	$1	$133	$14	$1
2014	138	14	1	133	14	1
2015	133	14	1	125	13	1
2016	120	16	1	111	15	1
2017	107	19	1	97	17	1
2018	98	21	1	87	18	1
2019	90	23	0	78	20	0
2020	80	20	0	68	17	0
2021	76	18	0	64	15	0
2022	73	16	0	60	13	0
2023	50	14	0	40	11	0
2024	50	12	0	39	9	0
2025	50	9	0	38	7	0
2026	50	7	0	38	5	0
2027	50	4	0	37	3	0
2028	47	2	0	34	1	0
2029	42	0	0	30	0	0
2030	37	0	0	26	0	0

All REC price projections through 2015 are derived from October 2013 futures market settlements.[11] Solar REC prices for 2017 and beyond are based on modeling results; the 2016 price is a bridge between current futures market prices and the modeling results. This bridge reflects an expected continuation of the rapid decline in solar costs and also reflects recognition of the three-year "shelf life" of Maryland RECs.[12]

Tier I REC prices for 2019 and beyond are based on the modeling results; the price projections for 2016 through 2018 are a bridge between current futures market prices and the modeling results. A three-year bridge is used to reflect a larger geographical pool of renewable resources, which can be generated anywhere in PJM or in adjacent RTOs/ISOs if the accompanying renewable energy is imported into PJM, relative to Solar RECs, which must be produced and generated in Maryland to be eligible for the Maryland RPS. The bridge values also reflect the lingering impact of the federal PTC, as the PTC can be taken for 10 years once a PTC-eligible project commences operation, as well as the three-year shelf life of Tier 1 RECs.[13]

[11] Spectrometer, *U.S. Environmental*, October 25, 2013.
[12] A Maryland-qualifying REC can be used to satisfy compliance requirements in the year that the REC was generated or in either of the two following years.
[13] Planned projects that meet IRS criteria by the end of 2013 are eligible for the PTC once the project is in operation, even if the wind facility comes online after 2013.

Finally, note that the nominal Solar REC prices between 2023 and 2027 are shown as equal to $50. This is because the modeled Solar REC prices during those years are higher than the Solar Alternative Compliance Payment (ACP) of $50 established in the Maryland RPS legislation. The ACP acts as a price cap in the Maryland Solar REC market.

5.2 Calculation of Avoided Renewable Energy Costs

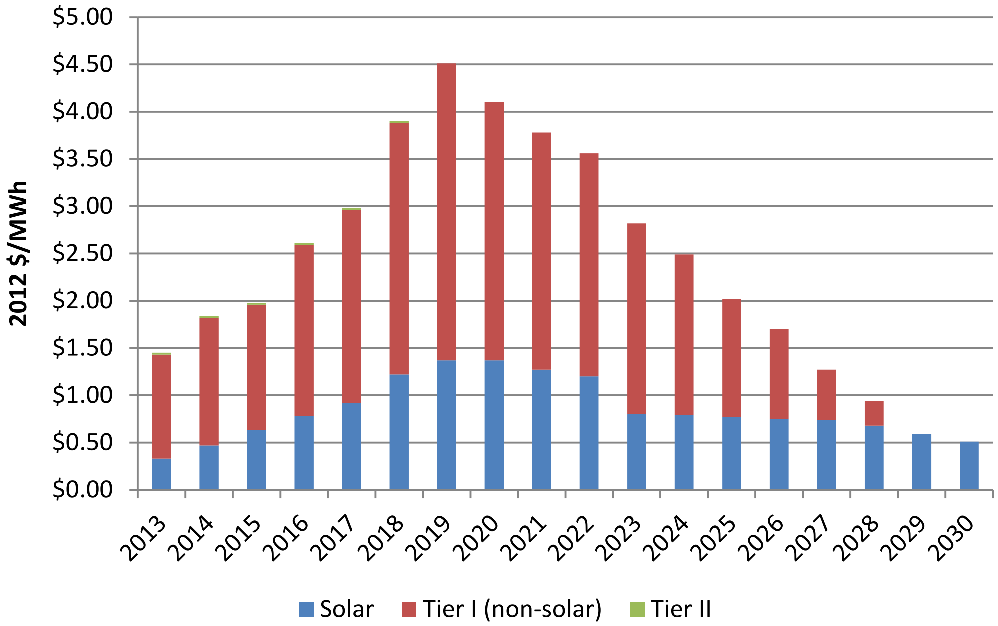
The estimated avoided cost of renewable energy is calculated by multiplying the annual REC price for each relevant category of RECs by the annual percentage requirement for each REC category. The renewable energy cost components (i.e., Solar, Tier 1, and Tier 2) are then summed each year, as shown below in Table 10. The avoided RPS cost in the far right column of Table 10 is representative of the renewable energy cost associated with one MWh of electric energy in Maryland (i.e., the avoided renewable energy cost per MWh of electric energy avoided). The avoided RPS cost is also shown graphically in Figure 6.

Table 10. Avoided Renewable Energy Costs (2012$/MWh)

Year	Solar	Tier I	Tier II	Avoided RPS Cost*
2013	$0.33	$1.10	$0.02	$1.44
2014	0.47	1.35	0.02	1.83
2015	0.63	1.33	0.02	1.98
2016	0.78	1.81	0.02	2.61
2017	0.92	2.04	0.02	2.99
2018	1.22	2.66	0.02	3.90
2019	1.37	3.14	0.00	4.51
2020	1.37	2.73	0.00	4.10
2021	1.27	2.51	0.00	3.78
2022	1.20	2.36	0.00	3.55
2023	0.80	2.02	0.00	2.82
2024	0.79	1.70	0.00	2.48
2025	0.77	1.25	0.00	2.02
2026	0.75	0.95	0.00	1.70
2027	0.74	0.53	0.00	1.27
2028	0.68	0.26	0.00	0.94
2029	0.59	0.00	0.00	0.59
2030	0.51	0.00	0.00	0.51

*Annual totals may not match the sum of the three components due to independent rounding.

Figure 6. Avoided RPS Cost (2012$/MWh)



5.3 REC Price Modeling

Long-term Tier 1 and Solar REC prices are estimated using a "gap analysis" model. The gap analysis model evaluates projected revenue and cost streams over the life of a new renewable energy facility and determines the REC price necessary to make a new renewable energy facility economic. Under this approach, the REC price needs to be sufficient to satisfy the marginal developer's revenue requirement given the capital cost of the project, the cost of capital, O&M expenses, and taxes, net of revenue obtained from the sale of energy and capacity, plus any government subsidies.

There are separate models for Solar and Tier 1 resources. The Tier 1 model assumes that the marginal resource which establishes Tier I REC prices in Maryland is a 200-MW land-based wind facility. For the Solar REC model, the marginal unit is a 10-MW utility-scale solar facility. The gap analysis model assumes that REC prices will be re-established each year with the construction of new renewable energy facilities, which account for declining capital costs and changing energy and capacity prices, among other factors.

Revenue and Cost Assumptions

The revenue stream consists of capacity market revenue, energy market revenue, revenue from the sale of RECs, and the investment tax credit for solar. The near-term value of the federal

PTC is reflected in current Tier 1 REC prices in the futures market. The value of the federal PTC is, therefore, not included in the long-term Tier 1 REC price modeling. The energy and capacity prices presented in the previous chapters are used in revenue projections for the REC price models. Costs include capital costs, O&M costs, debt servicing, and taxes. An overview of the REC price modeling assumptions is presented below in Table 11, and a discussion of these assumptions is provided following the table.

Table 11. REC Price Modeling Assumptions

Assumptions	Solar Facility	Wind Facility
Technical Inputs		
Size of Facility (MW)	10	200
Useful Life of Project (years)	25	25
Capacity Factor	15%	30%
Annual Degradation Rate of Output	0.5%	--
Financial Inputs		
Rate of Inflation	2.1%	2.1%
Project Costs		
Overnight Construction Costs	See Table 12	
Project Financing Parameters		
Equity Ratio	50.0%	50.0%
Cost Rate of Equity	12.0%	12.0%
Cost Rate of Debt	7.0%	7.0%
Weighted Average Cost of Capital	9.5%	9.5%
Effective Tax Rate	40.4%	40.4%
Fixed O&M Costs (2012$/kW-year)	$21.74	$39.54
Variable O&M Costs (2012$/MWh)	$0.00	$0.00
Sources of Revenues for Developer (excluding RECs):		
Energy Market Revenue	Average of PJM-MidE, PJM-SW, and PJM-APS energy prices.	
Capacity Market Revenue	Average of PJM-MidE, PJM-SW, and PJM-APS capacity prices.	
PJM Capacity Derate for Renew. Resource	38.0%	13.0%
Capacity Eligible for PJM Capacity Market	3 MW	26 MW
Investment Tax Credit (as a percent of capital costs)	2013-2016: 30% 2017-2030: 10%	--

Operations and Maintenance Costs

The fixed O&M cost assumptions are based on the AEO 2013.[14] Variable O&M costs are assumed to equal zero for both solar and wind facilities. These cost estimates are held constant (in real terms) during the analysis period.

Capital Costs

Capital cost assumptions are based on a review of recent data from various publications, as well as correspondence with state and federal agencies and representatives from the solar industry. The initial year cost assumptions are based on observed capital costs in 2012. The 2012 costs are extrapolated over the analysis period based on assumptions developed by Exeter. Considerations include historical data, industry expectations, and recent and future developments that affect the uncertainty associated with projections of future capital costs for renewable energy projects.

The capital cost assumptions Exeter developed are shown below in Table 12. There is a high degree of uncertainty associated with projecting capital costs for new renewable energy facilities due to several unpredictable variables. Examples include whether the rapid declines in solar costs will continue and if so, for how long and at what rate; the availability of federal incentives such as the PTC and the investment tax credit; and the impact of the recently imposed U.S. tariff on solar panels imported from China. The methodology and rationale for extrapolating the 2012 costs are explained following Table 12.

[14] U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013, Electricity Market Module*, April 2013. EIA's assumptions were escalated from 2011 dollars to 2012 dollars using the Implicit Price Deflator for Gross Domestic Product (GDP) from the U.S. Department of Commerce, Bureau of Economic Analysis.

Table 12. Capital Cost Assumptions for New Renewable Energy Projects (2012$/kW)

Year	Solar PV Overnight Construction Costs	Solar PV Percent Decline	Land-based Wind Overnight Construction Costs	Land-based Wind Percent Decline
2012	$3,250	--	$2,000	--
2013	3,023	7%	1,980	1%
2014	2,811	7	1,960	1
2015	2,614	7	1,941	1
2016	2,431	7	1,921	1
2017	2,285	6	1,902	1
2018	2,171	5	1,883	1
2019	2,084	4	1,864	1
2020	2,022	3	1,845	1
2021	1,981	2	1,827	1
2022	1,961	1	1,809	1
2023	1,942	1	1,791	1
2024	1,922	1	1,773	1
2025	1,903	1	1,755	1
2026	1,884	1	1,737	1
2027	1,865	1	1,720	1
2028	1,847	1	1,703	1
2029	1,828	1	1,686	1
2030	1,810	1	1,669	1

Solar PV Capital Cost Assumptions

The 2012 capital cost figure for solar PV is based on data gathered by the Lawrence Berkeley National Laboratory (LBNL). The average capital cost for utility-scale (greater than 2 MW) fixed-tilt solar projects installed in 2012 was about $3,200 per kW and $3,300 per kW for crystalline and thin-film systems, respectively.[15]

Installed prices for fixed-tilt solar systems declined by about 7 percent per year between 2010 and 2012 (see Figure 7 below). A review of the existing literature suggests the trend of annually declining solar costs is expected to continue throughout the avoided cost study analysis period. Capital costs for solar PV are projected to decline at or near the historical rate in the near-term, but eventually taper off and decline at a slower rate in the long-term. Figure 8 and Figure 9 on the following page demonstrate this trend. However, as shown in Figure 8 and Figure 9, there is uncertainty associated with the magnitude and timing of these changes (i.e., the rate at which costs decline and the timeframe in which the rate of decline begins to taper).

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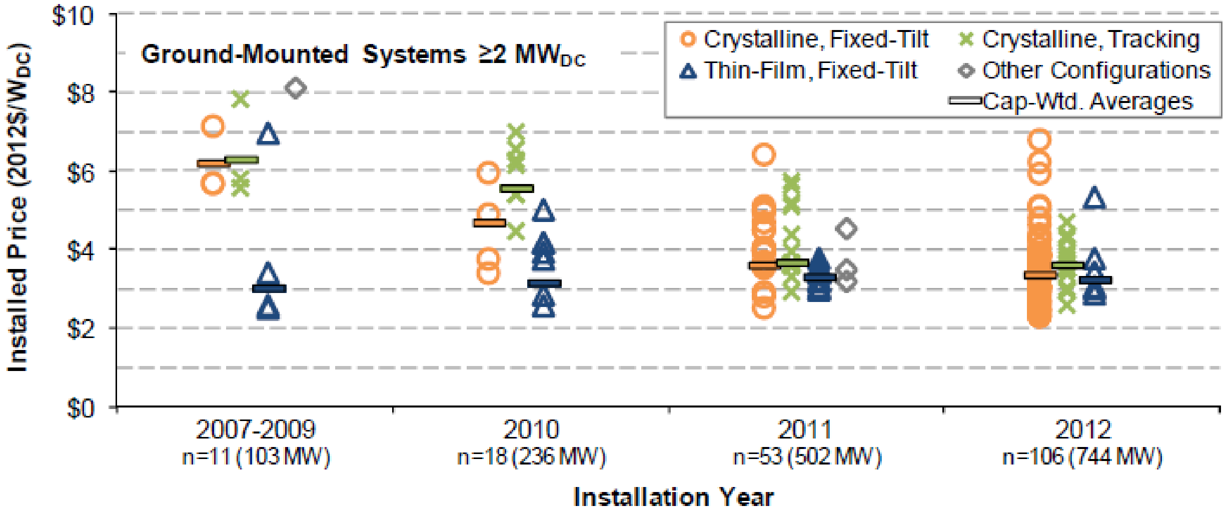
[15] Lawrence Berkeley National Laboratory, *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, July 2013, http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

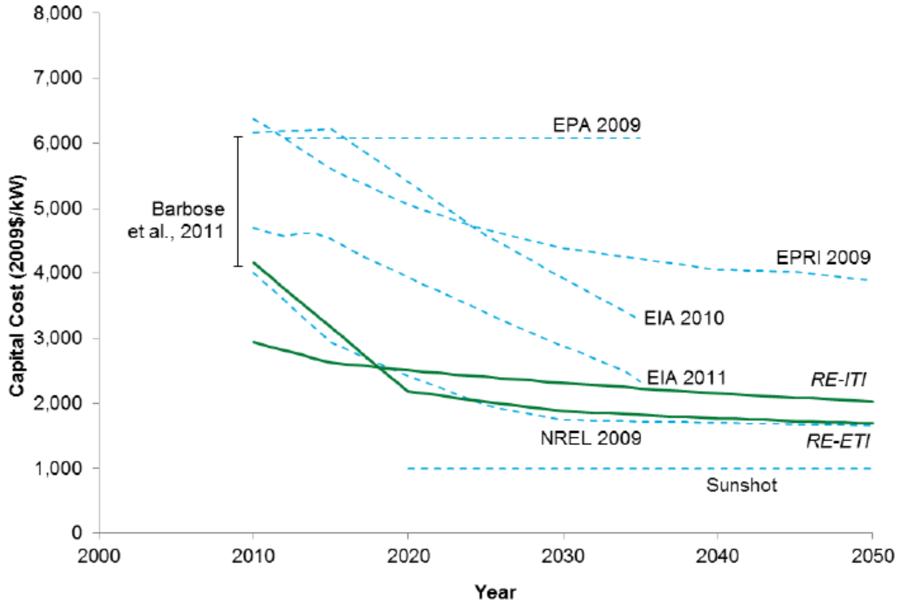
For the avoided cost study assumptions, Exeter extrapolated the observed annual rate of decline in solar capital costs through 2016 based on the historical trend exhibited in Figure 7. Beginning in 2017, the annual decline in solar capital costs is assumed to slow by 1 percent per year, eventually leveling out to an annual decline of 1 percent beginning in 2022, as previously shown in Table 12.

Figure 7. Installed Price of Utility-Scale PV



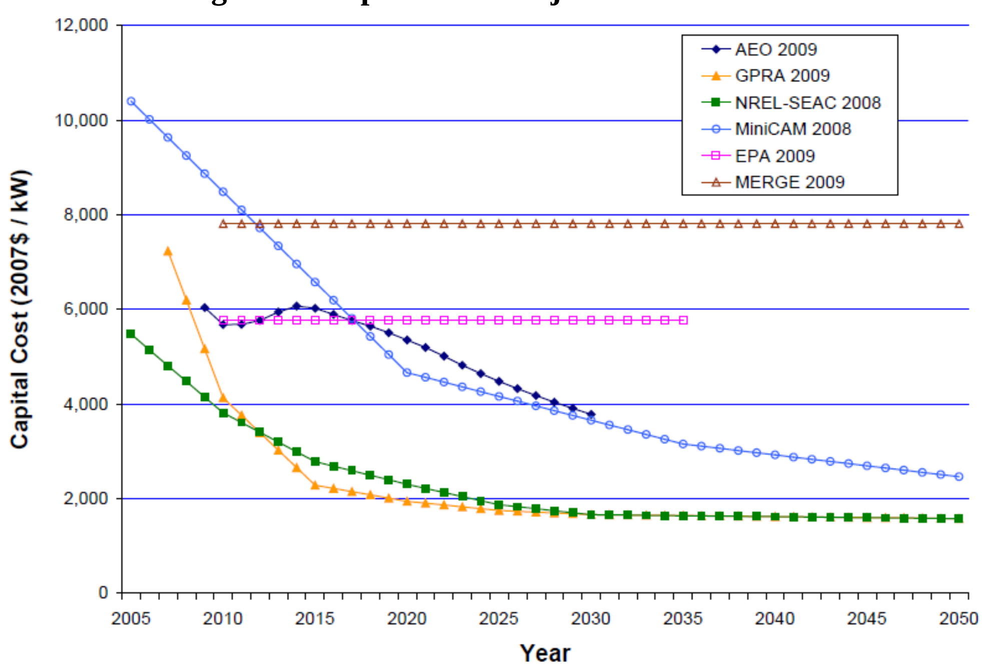
Source: Lawrence Berkeley National Laboratory, *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, July 2013, http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

Figure 8. Capital Cost Projections for Single-Axis Tracking Solar PV



Source: National Renewable Energy Laboratory, *Renewable Electricity Futures Study*, 2012, http://www.nrel.gov/analysis/re_futures/.

Figure 9. Capital Cost Projections for Solar PV



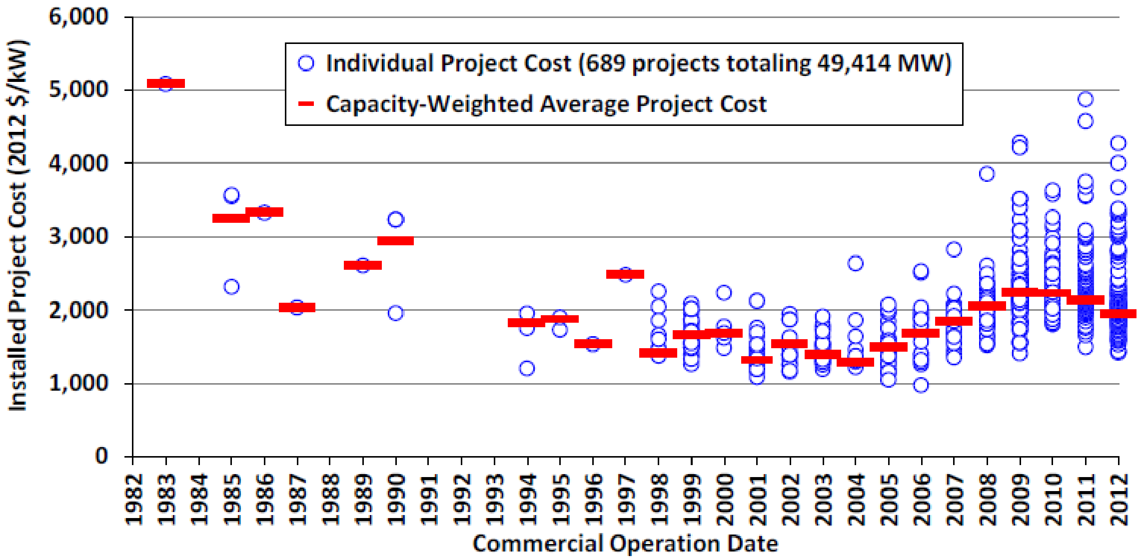
Source: ICF International, *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*, November 2010, http://www.nrel.gov/docs/fy11osti/48595.pdf.

Land-based Wind Capital Cost Assumptions

The 2012 capital cost figure for land-based wind is based on data gathered by LBNL. The average installed land-based wind power project cost in the U.S. Northeast was $2,002 per kW in 2012.[16] Note that the average cost for the entire U.S. was $1,943 per kW; approximately 3 percent below the Northeast cost.

The historical capital costs for land-based wind projects have been volatile (see Figure 10 below), making a trend analysis to project future capital costs for land-based wind unworkable. However, as shown in Figure 11 and Figure 12 on the following page, capital cost projections for future wind facilities are more consistent in terms of magnitude, as compared to capital cost estimates for solar. The projections suggest there is a general consensus that capital costs for land-based wind will decline (in real terms) over time. Furthermore, the annual rate of decline during the avoided cost study period is expected to be less steep and more consistent as compared to projections for solar capital costs. Exeter adopted an assumption of a 1 percent annual reduction in capital costs for new land-based wind facilities (see Table 12 on page 18).

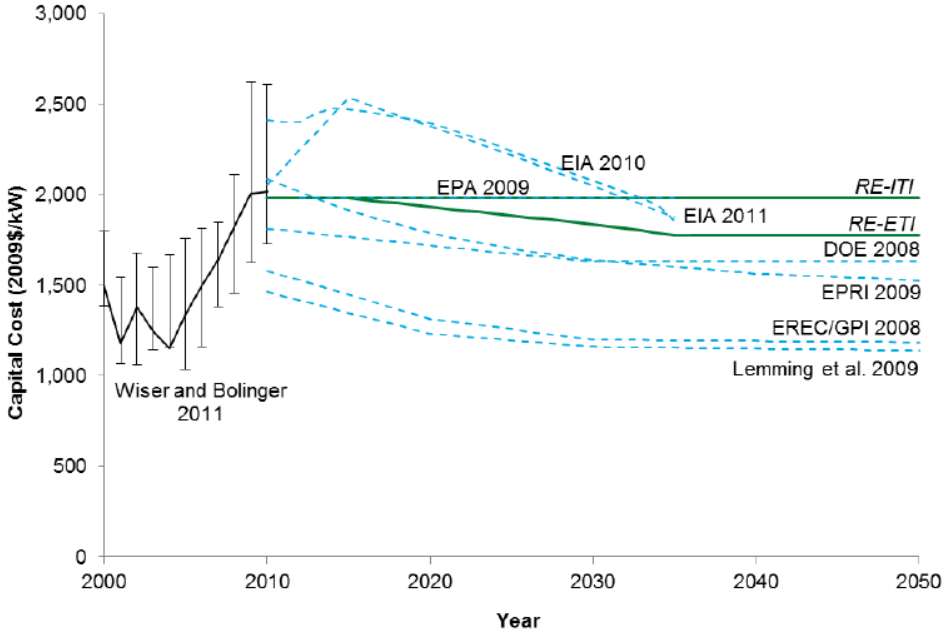
Figure 10. Installed Land-based Wind Power Project Costs



Source: Lawrence Berkeley National Laboratory, 2012 *Wind Technology Market Report*, August 2013, http://emp.lbl.gov/sites/all/files/lbnl-6356e.pdf.

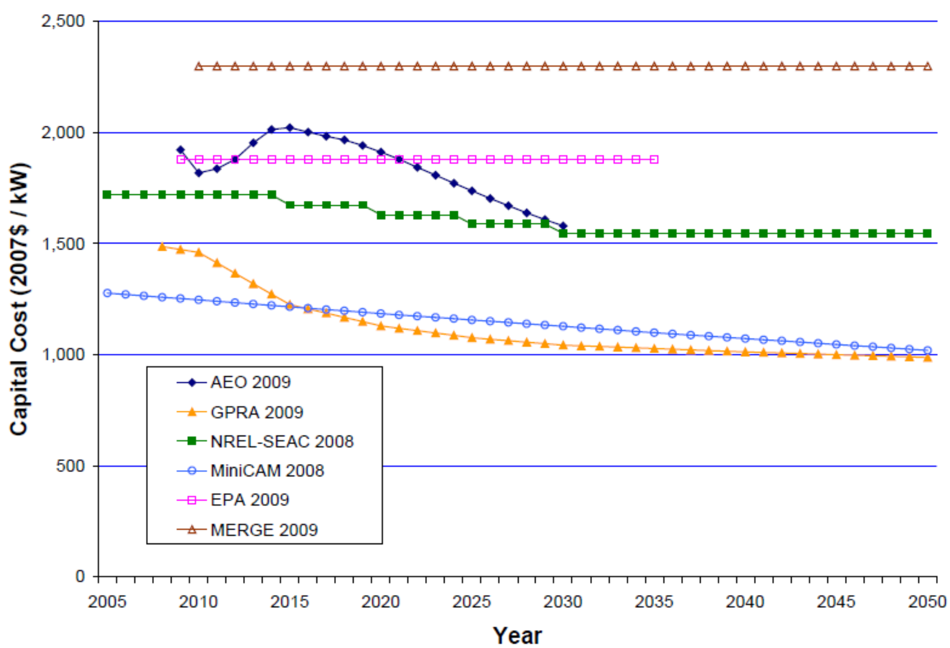
[16] Lawrence Berkeley National Laboratory, *2012 Wind Technology Market Report*, August 2013, http://emp.lbl.gov/sites/all/files/lbnl-6356e.pdf.

Figure 11. Historical and Future Capital Costs for Land-based Wind Energy



Source: National Renewable Energy Laboratory, *Renewable Electricity Futures Study*, 2012, http://www.nrel.gov/analysis/re_futures/.

Figure 12. Capital Cost Projections for Land-based Wind Energy



Source: ICF International, *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*, November 2010, http://www.nrel.gov/docs/fy11osti/48595.pdf.

6. Transmission and Distribution Costs

Avoided T&D costs reflect the deferred or reduced investments in electric T&D systems resulting from energy efficiency or demand response measures in specific areas that would otherwise require such investments. It was Exeter's intention to utilize an approach similar to the methodology employed by Synapse Energy Economics for its New England analysis, based upon a methodology developed by ICF Consulting in 2005. However, concerns arose by Exeter and others that this approach may not be appropriate for Maryland due to slow load growth in the State in recent years, combined with increasing T&D investment for reliability purposes rather than to accommodate load growth. As such, utility-provided estimates have been adopted for this report following discussions with MEA and receipt of feedback from stakeholders.

In 2013, BGE developed avoided T&D cost estimates based on the replacement cost of a distribution substation and the value of importing electricity into its transmission system. These estimates were developed as metrics for BGE's Advanced Metering Infrastructure (AMI) initiative under Case No. 9208 at the Maryland PSC, and are the basis for the values included in Table 13. A more detailed description of the BGE methodology is provided following the table. Using a similar methodology, the PHI utilities are expected to file avoided T&D cost estimates under Case No. 9207 for their own AMI avoided cost metrics.[17] Finally, in comments provided to MEA, Potomac Edison recommended the use of a proxy of $25/kW-year for avoided T&D costs based on the experience of the Statewide Evaluator in Pennsylvania.[18] This proxy value is included in this avoided cost report as a default value for the PHI utilities and Potomac Edison until the utilities perform independent avoided T&D cost analyses.

The utility-provided estimates are presented in 2012 dollars in Table 13. Estimated avoided T&D costs are held constant in real dollars during the avoided cost study analysis period (i.e., avoided T&D costs are assumed to increase with inflation).

Table 13. Avoided T&D Costs (2012$)

Utility	$/kW-year	$/MW-day
BGE	$34.13	$93.49
Potomac Edison	25.00	68.49
Pepco/SMECO	25.00	68.49
DPL	25.00	68.49

[17] Calvin Timmerman, Maryland Public Service Commission, personal communication, February 27, 2014.
[18] Pennsylvania Public Utility Commission, Final Order for the Energy Efficiency and Conservation Program, Docket Nos. M-2012-2289411 and M-2008-2069887, February 20, 2014, p.26.

6.1 BGE's Avoided T&D Cost Estimation Methodology

For avoided transmission costs, BGE first defined transmission as infrastructure providing import capability at the 230 kV and 500 kV level. Next, BGE escalated its actual capital cost of transmission over the last 45 years to 2012 dollars.[19] BGE then estimated the load carrying capability of transmission at the Capacity Emergency Transfer Limit (CETL). For the purposes of this report, BGE's avoided transmission cost is calculated as capital costs divided by CETL, then multiplied by an asset life discount factor for an energy efficiency/conservation project with an asset life of 10.5 years. In BGE's original analysis, the utility estimated asset life discount factors that would provide for different avoided transmission cost estimates for energy efficiency/conservation projects with different lifespans. 10.5 years is used herein because it represents the average estimated useful life for BGE's 2012 EmPOWER Maryland programs.

The methodology BGE used to estimate avoided distribution costs is similar to its avoided transmission cost methodology. First, BGE defined distribution infrastructure as substations only (below the 230 kV level) and escalated its actual capital cost of distribution over the last 45 years to 2012 dollars. Next, BGE estimated the load carrying capability of distribution as the all-time, unrestricted, peak load not normalized for weather. Finally, and in contrast to its avoided transmission cost methodology, BGE utilized a "functionality discount factor" of 1.5 to take into account the fact that energy efficiency measures do not have the ability to be controlled locally to address specific local distribution feeder issues. Avoided distribution costs are calculated herein as capital costs divided by peak load divided by the functionality discount factor, then multiplied by the 10.5 year asset life discount factor. BGE also used varying asset life discount factors for its estimated avoided distribution costs.

[19] This provides an estimate of the replacement cost of the relevant portion of the transmission system.

7. Demand Reduction Induced Price Effects

7.1 Introduction

For electric energy and capacity, the reduced demand for electric power associated with electricity efficiency and conservation program implementation has implications for market prices. A reduction in electric demand means less generation is needed, and savings are realized through the displacement of the more expensive marginal generation plants. This is known as Demand Reduction Induced Price Effects, or DRIPE. The changes in market prices (both for energy and capacity) owing to the changes in the demand for energy and capacity need to then be multiplied by the remaining quantity of electricity and capacity demanded to determine the change in total costs to Marylanders. Energy DRIPE represents the total economic benefit to Maryland consumers (price change times quantity) associated with a 1-MWh reduction in quantity of energy demanded. The capacity DRIPE is the total economic benefit to Maryland customers associated with a 1-MW-day reduction in the amount of capacity demanded, i.e., a 1-MW reduction in peak demand. Note that additional economic benefits would accrue to out-of-state customers associated with reductions in the price of both energy and capacity. For purposes of computing Maryland avoided costs, any benefits that would accrue to customers outside of Maryland have been excluded from this analysis. The methodological equations developed by Exeter to estimate DRIPE are presented in Appendix 3.

7.2 General Methodology

The methodologies used to calculate the energy and capacity components of DRIPE are similar in concept though there are a few mechanical differences that were necessitated to accommodate modeling considerations. For clarity of exposition, the energy DRIPE and capacity DRIPE estimation approaches are discussed separately. DRIPE values differ depending on when an energy efficiency or demand reduction measure is installed. Presented in this report are separate DRIPE value for measures installed in 2015, 2016, and 2017 (i.e., during the next EmPOWER Maryland planning period).

Energy DRIPE

To calculate the energy DRIPE, which differs across zones in Maryland, the following approach was used:

Step 1 – Baseline Electric Energy Costs: The baseline electric energy costs were developed using the Ventyx model, which computes electric energy prices for each hour of the year for the 18-year period from 2013 through 2030 for each relevant transmission zone in the U.S. A description of the model, along with key modeling assumptions, is contained in Chapter 2 addressing the avoided cost estimation methodology. DRIPE was calculated separately for the three Ventyx zones that include portions of Maryland: PJM Southwest (which includes the BGE, Pepco, and SMECO areas); the PJM Mideast zone, which includes the Maryland Eastern Shore (including DPL and the Choptank Electric Cooperative); and the PJM APS zone, which includes Potomac Edison.

Step 2 – Reduced Load Energy Costs: To estimate the change in electric energy prices by zone, the load requirements included in the Avoided Cost Study (ACS) Base Case were marginally reduced in each hour of each year by a fixed amount, which varied by zone. For the PJM-SW zone, load in each hour was reduced by 200 MW; by 150 MW in each hour in the PJM-APS zone; and by 300 MW in each hour in the PJM-MidE zone. Three separate model runs were conducted to accommodate the reduction in each of the zones. That is, to allow for the DRIPE estimation for PJM-SW, for example, a separate model run was made which only differs from the ACS Base Case by placing PJM-SW loads lower by 200 MW in each hour; loads in the remainder of PJM are unchanged. Because the Ventyx model accounts for imports into and exports out of each zone, the changes in load in PJM-SW affect not only prices in the PJM-SW zone but also in other zones within PJM. Reliance on separate runs for marginal decreases in load for each of the three Ventyx transmission zones located in Maryland facilitates the isolation of price impacts associated with energy efficiency/conservation load reductions located within the service areas of each of the electric distribution companies in the State.

The magnitudes of the changes in load in each of the three Ventyx transmission zones located, in part, within Maryland represent small but measurable changes in zonal loads. The PJM-MidE zone, which encompasses not only the Delmarva Peninsula but also New Jersey and the Philadelphia area, is the largest zone in terms of total load and therefore, a larger hourly load reduction (300 MW) was required to ensure meaningful results. Smaller load reductions for the PJM-SW zone and the PJM-APS zone are comparable on a percentage basis to the 300-MW reduction in hourly loads used for PJM-MidE.

Step 3 – Calculate the Energy Price Differentials: The differential electric energy prices were computed by subtracting the reduced load scenario prices from the prices resulting from the ACS Base Case run. This exercise generated hourly energy price differentials for each of the three transmission zones in each of the three load reduction scenarios – one for each transmission zone. The energy price differentials were then averaged separately over on-peak hours and off-peak hours to provide hours-weighted annual average on-peak and off-peak energy price differentials for each of the analysis years for each of the zones.

This methodology is employed to estimate energy DRIPE for measures installed in 2015 and 2016. It would be inappropriate to use this methodology for measures installed in

2017, as that is the first year in which the Ventyx model builds new power plants in the ACS Base Case. Additional modeling runs would have been necessary to use this method to estimate energy DRIPE for measures installed in 2017, but for practical reasons the inclusion of energy DRIPE for multiple implementation years was decided upon near the end of the study process. As a proxy for energy DRIPE for measures installed in 2017, the 2016 energy DRPE values were shifted forward by one year and a 15 percent reduction was applied. This approach was suggested by MEA and adopted by Exeter based on consensus from the stakeholder group.

The modeled energy price differentials are presented in the tables below. Each table shows the change in energy prices in the Maryland transmission zones associated with the load reduction in the transmission zone specified in the title of the relevant table. Note that a positive value indicates a reduction from the ACS Base Case energy price. Likewise, a negative value indicates negative DRIPE, i.e., a price increase relative to the ACS Base Case. For measures installed in 2016, the rows for 2015 should be disregarded. For measures installed in 2017, the energy price differentials are adjusted based on the consensus methodology described above.

Table 14. Energy Price Differentials for a Measure Installed in PJM-SW (2012$/MWh)

	On-Peak			Off-Peak		
	PJM-SW	PJM-MidE	PJM-APS	PJM-SW	PJM-MidE	PJM-APS
2015	$0.42	$0.20	$0.20	$0.07	$0.06	$0.06
2016	0.31	0.18	0.19	0.08	0.06	0.07
2017	0.20	0.17	0.15	0.08	0.06	0.06
2018	0.11	0.13	0.11	0.07	0.05	0.05
2019	0.12	0.07	0.11	0.08	0.05	0.06
2020	(0.01)	(0.03)	0.09	0.08	0.05	0.07
2021	0.04	(0.13)	0.05	0.05	0.00	0.05
2022	(0.03)	(0.20)	0.02	0.03	(0.05)	0.02
2023	0.08	(0.14)	0.02	0.02	(0.10)	(0.02)
2024	0.03	(0.07)	0.05	0.06	(0.11)	(0.03)
2025	0.07	(0.02)	(0.00)	0.08	(0.13)	(0.01)
2026	0.02	(0.09)	(0.05)	0.09	(0.14)	0.02
2027	0.03	(0.08)	(0.08)	0.07	(0.15)	0.04
2028	0.00	(0.12)	(0.04)	0.05	(0.15)	0.06
2029	0.05	(0.08)	(0.03)	0.06	(0.17)	0.05
2030	0.02	(0.12)	(0.04)	0.06	(0.16)	0.04

Table 15. Energy Price Differentials for a Measure Installed in PJM-MidE (2012$/MWh)

	On-Peak			Off-Peak		
	PJM-SW	PJM-MidE	PJM-APS	PJM-SW	PJM-MidE	PJM-APS
2015	$0.21	$0.49	$0.17	$0.07	$0.17	$0.06
2016	0.15	0.48	0.15	0.08	0.19	0.08
2017	0.27	0.33	0.13	0.08	0.19	0.08
2018	0.19	0.20	0.05	0.08	0.16	0.08
2019	0.20	0.18	0.03	0.07	0.14	0.08
2020	0.08	0.12	0.02	0.07	0.13	0.08
2021	(0.03)	0.02	(0.01)	0.05	0.08	0.04
2022	(0.06)	(0.05)	(0.01)	0.04	0.03	0.02
2023	(0.06)	(0.00)	(0.06)	0.00	(0.03)	(0.02)
2024	(0.02)	0.03	(0.08)	(0.01)	(0.03)	(0.01)
2025	(0.08)	(0.01)	(0.17)	(0.03)	(0.04)	(0.01)
2026	(0.17)	(0.06)	(0.20)	(0.03)	(0.03)	(0.01)
2027	(0.15)	(0.03)	(0.20)	(0.03)	(0.03)	(0.01)
2028	(0.14)	(0.01)	(0.15)	(0.03)	(0.03)	(0.01)
2029	(0.08)	0.02	(0.11)	(0.02)	(0.07)	(0.00)
2030	(0.10)	0.03	(0.12)	(0.01)	(0.08)	(0.01)

Table 16. Energy Price Differentials for a Measure Installed in PJM-APS (2012$/MWh)

	On-Peak			Off-Peak		
	PJM-SW	PJM-MidE	PJM-APS	PJM-SW	PJM-MidE	PJM-APS
2015	($0.07)	$0.02	$0.14	$0.05	$0.05	$0.07
2016	0.03	0.04	0.12	0.06	0.06	0.06
2017	0.17	0.25	0.13	0.09	0.10	0.09
2018	0.21	0.21	0.12	0.09	0.09	0.10
2019	0.16	0.12	0.12	0.09	0.10	0.13
2020	0.06	(0.21)	0.07	0.06	0.04	0.10
2021	0.11	(0.15)	0.05	0.05	0.04	0.10
2022	0.16	(0.06)	0.06	0.04	0.03	0.08
2023	0.13	0.11	0.09	0.04	0.03	0.07
2024	0.12	0.10	0.12	0.03	0.03	0.08
2025	0.10	0.13	0.07	0.03	0.03	0.10
2026	0.05	0.05	0.03	0.04	0.03	0.10
2027	0.02	0.07	0.01	0.04	0.02	0.08
2028	(0.10)	(0.15)	0.01	0.02	(0.05)	0.06
2029	(0.10)	(0.18)	(0.02)	0.00	(0.14)	0.06
2030	(0.17)	(0.32)	(0.08)	(0.01)	(0.21)	0.06

Step 4 – Allocate Price Reduction Benefits to Maryland Ratepayers: The energy price differentials were divided by the reduction in MW in each hour (e.g., for PJM-SW during the on-peak period, the denominator is equal to 200 MW times on-peak hours in the year) to obtain an estimate of the price differential that would be associated with the reduction of a single MWh for each zone, for each load reduction scenario, for on-peak and off-peak periods, and for each year of the analysis period. The resulting figures were then multiplied by the total energy consumed in the Maryland portion of each transmission zone to come up with a Maryland-specific energy savings (or cost) per MWh avoided in each zone. For each load reduction scenario, for on-peak and off-peak periods, and for each year of the analysis period, the three zonal energy savings (or cost) per MWh figures were summed to reflect the total energy DRIPE impact in Maryland.

Step 5 – Application of Decay Rate: To recognize that consumers and suppliers will adjust demand and supply in response to changes in prices, we assumed that the impact of the change in the quantity of energy demanded would decay over time. The decay rate employed for the energy DRIPE analysis is 20 percent, i.e., in each year, the weighted average price differential is multiplied by a factor equal to $(1-0.2)^t$ where "t" is equal to 1 in the year that the energy efficiency/conservation measure is assumed to be implemented, and increases by 1 in each year thereafter. The decay scaling factor for a measure installed in 2015, therefore, would be equal to 0.33 by year 5 (2019) and equal to 0.11 by year 10 (2024).

Capacity DRIPE

To calculate the capacity DRIPE, a different approach was employed due to the method by which the Ventyx model computes capacity prices. In the Ventyx model, capacity prices are calculated as the residual revenue stream (i.e., revenue in addition to energy revenue) needed to fully compensate the marginal power plant for all costs. Consequently, a decrease in the energy price resulting from a reduction in the demand for electric energy would have the effect of increasing the modeled capacity price. While the method employed by Ventyx for the estimation of capacity prices is acceptable for longer-term trends and levels in the price of capacity, the reliance on the model for the calculation of capacity DRIPE was determined to introduce conceptual problems which could not be readily resolved. As an alternative, Exeter employed a method whereby the estimated zonal supply elasticities were obtained using the zonal capacity supply curves from the most recent PJM Base Residual Auction (BRA). These supply elasticities were used to determine the change in price for each relevant zone given a change in the quantity of MW required to meet the PJM capacity requirement.

As noted above, the calculation of energy DRIPE considered the changes in the price of energy not only in the zone in which the electric energy reduction took place but also in the other transmission zones that encompass portions of Maryland. For the calculation of the capacity DRIPE, only the capacity price change in the directly affected zone is considered.

Step 1 – Calculation of the Supply Elasticities: Separate supply elasticities were estimated for EMAAC (which corresponds to the PJM-MidE transmission zone defined by Ventyx and includes DPL), SWMAAC (which corresponds to the PJM-SW transmission zone defined by Ventyx and includes BGE and Pepco), and for PJM as a whole (for the APS transmission zone defined by Ventyx). Because the supply elasticity is not constant over the full range of the capacity supply curve, the elasticity was measured for the portion of the supply curve where it intersects the Variable Resource Requirement (VRR) curve (i.e., the PJM administratively determined demand curve). This point of intersection represents market equilibrium, and provides the market clearing price. With the estimation of the supply elasticities, which define the supply relationship between changes in price and changes in quantity, it was possible to calculate the change in the price that would accompany a change in the quantity of capacity required.

Step 2 – Calculation of the Capacity Price Differentials: The change in price for a given change in quantity, obtained from the estimated supply elasticities, was applied to the capacity price forecast for each of the three transmission zones to calculate the change in capacity prices on a dollars per MW-day basis. The derived differentials, expressed in 2012 dollars per MW-day, were then grossed up to account for the PJM reserve margin. This set of calculations provided estimated price differentials, by zone, for the three different transmission zones associated with a one MW-day change in capacity, adjusted for reserve requirements. The estimated capacity price differentials (adjusted for reserve requirements) are shown in Table 17.

Table 17. DRIPE Capacity Price Differentials (2012$/MW-day)

	Pepco/BGE/ SMECO	DPL	Potomac Edison
2015	$0.11	$0.07	$0.02
2016	0.09	0.06	0.01
2017	0.10	0.07	0.01
2018	0.11	0.07	0.01
2019	0.11	0.08	0.01
2020	0.12	0.08	0.02
2021	0.12	0.08	0.02
2022	0.13	0.09	0.02
2023	0.14	0.09	0.02
2024	0.14	0.10	0.02
2025	0.15	0.10	0.02
2026	0.16	0.11	0.02
2027	0.17	0.12	0.02
2028	0.18	0.12	0.02
2029	0.19	0.13	0.03
2030	0.20	0.14	0.03

Step 3 – Application of Decay Rate: To recognize that suppliers will adjust supply in response to changes in prices, Exeter assumed that the impact of the change in the quantity of capacity supplied would decay over time. The decay rate employed for the capacity DRIPE analysis is 20 percent, the same decay rate used for the energy DRIPE. As with the energy DRIPE, in each year, the calculated change in the capacity price is multiplied by a factor equal to $(1\text{-}0.2)^t$ where "t" is equal to 1 in the year that the energy efficiency/conservation measure is assumed to be implemented, and increases by 1 in each year thereafter. The decay scaling factor for a measure installed in 2015, therefore, would be equal to 0.33 by year 5 (2019) and equal to 0.11 by year 10 (2024).

Step 4 – Calculation of Total DRIPE: The final step was to multiply the per-MW-day DRIPE estimates by the number of MW in the Maryland portion of each of the relevant zones to compute the total Maryland capacity-related DRIPE (per MW of demand reduction) associated with an efficiency/conservation program implemented in each zone and for each year. Because of the decay factor, capacity DRIPE differs for measures installed in different years.

7.3 DRIPE Estimation Results

The estimated energy-related, per-MWh savings (or costs) in Maryland associated with DRIPE are shown below, and are provided separately for on-peak and off-peak hours, by implementation year, and by the utility service area in which the energy efficiency/conservation measure is implemented. The energy DRIPE values incorporate the impacts associated with all three of the zones given a program implemented in the specified year and in the designated zone.

Table 18. Total Avoided Cost in Maryland per MWh Saved for Measures Installed in 2015 (2012$/MWh)

	Pepco/SMECO/BGE		DPL		Potomac Edison	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2015	$13.26	$1.83	$5.70	$1.39	$(1.72)	$1.88
2016	8.18	1.61	3.63	1.36	1.55	1.79
2017	4.48	1.28	4.14	1.10	5.52	2.15
2018	2.11	0.98	2.23	0.86	5.14	1.71
2019	1.76	0.83	1.83	0.61	3.04	1.51
2020	0.03	0.66	0.65	0.50	0.59	0.78
2021	0.22	0.33	(0.13)	0.26	0.99	0.59
2022	(0.37)	0.14	(0.28)	0.14	1.36	0.36
2023	0.29	0.02	(0.25)	(0.01)	1.05	0.25
2024	0.13	0.12	(0.07)	(0.03)	0.81	0.21
2025	0.20	0.15	(0.24)	(0.05)	0.57	0.17
2026	(0.00)	0.15	(0.38)	(0.05)	0.20	0.16
2027	0.01	0.09	(0.26)	(0.04)	0.09	0.12
2028	(0.04)	0.05	(0.19)	(0.03)	(0.28)	0.03
2029	0.04	0.04	(0.08)	(0.02)	(0.25)	(0.01)
2030	(0.00)	0.04	(0.09)	(0.01)	(0.34)	(0.03)

Table 19. Total Avoided Cost in Maryland per MWh Saved for Measures Installed in 2016 (2012$/MWh)

	Pepco/SMECO/BGE		DPL		Potomac Edison	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2016	$10.22	$2.01	$4.54	$1.70	$1.94	$2.24
2017	5.60	1.60	5.18	1.38	6.90	2.69
2018	2.64	1.23	2.78	1.07	6.42	2.14
2019	2.20	1.04	2.28	0.76	3.80	1.89
2020	0.04	0.83	0.81	0.63	0.74	0.97
2021	0.27	0.41	(0.16)	0.32	1.23	0.73
2022	(0.46)	0.17	(0.35)	0.17	1.70	0.45
2023	0.36	0.02	(0.31)	(0.02)	1.32	0.32
2024	0.16	0.15	(0.09)	(0.04)	1.01	0.26
2025	0.26	0.18	(0.31)	(0.07)	0.72	0.21
2026	(0.01)	0.18	(0.47)	(0.06)	0.25	0.20
2027	0.02	0.12	(0.33)	(0.05)	0.11	0.14
2028	(0.05)	0.06	(0.24)	(0.04)	(0.35)	0.04
2029	0.05	0.05	(0.11)	(0.02)	(0.31)	(0.02)
2030	(0.00)	0.05	(0.11)	(0.02)	(0.42)	(0.04)

Table 20. Total Avoided Cost in Maryland per MWh Saved for Measures Installed in 2017 (2012$/MWh)

	Pepco/SMECO/BGE		DPL		Potomac Edison	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2017	$8.69	$1.71	$3.86	$1.44	$1.65	$1.90
2018	4.76	1.36	4.40	1.17	5.87	2.29
2019	2.24	1.04	2.37	0.91	5.46	1.82
2020	1.87	0.88	1.94	0.65	3.23	1.60
2021	0.04	0.70	0.69	0.53	0.63	0.83
2022	0.23	0.35	(0.14)	0.28	1.05	0.62
2023	(0.39)	0.15	(0.30)	0.15	1.45	0.38
2024	0.31	0.02	(0.27)	(0.01)	1.12	0.27
2025	0.14	0.12	(0.07)	(0.03)	0.86	0.22
2026	0.22	0.16	(0.26)	(0.06)	0.61	0.18
2027	(0.01)	0.16	(0.40)	(0.05)	0.22	0.17
2028	0.02	0.10	(0.28)	(0.04)	0.09	0.12
2029	(0.04)	0.05	(0.20)	(0.04)	(0.30)	0.04
2030	0.05	0.04	(0.09)	(0.02)	(0.26)	(0.01)

The estimation of capacity-related per MW-day savings in Maryland associated with DRIPE are shown below in Table 21, and are provided for each utility in which the energy efficiency/conservation project is implemented. Values include the adjustment for the PJM reserve margin (approximately 9 percent) and are expressed in 2012 dollars per MW-day.

Table 21. Total Avoided Cost in Maryland per MW-day Saved for Measures Installed in 2015 (2012$/MW-day)

Year	Pepco, SMECO, & BGE	DPL	Potomac Edison
2015	$940.08	$63.44	$25.23
2016	671.54	45.43	13.93
2017	581.79	40.41	10.55
2018	494.25	34.25	8.97
2019	420.37	29.08	7.65
2020	357.71	24.69	6.53
2021	304.01	21.03	5.56
2022	258.25	17.91	4.74
2023	219.55	15.23	4.04
2024	186.42	12.93	3.43
2025	158.48	11.00	2.92
2026	134.62	9.37	2.49
2027	114.32	7.96	2.12
2028	97.03	6.77	1.81
2029	82.41	5.76	1.54
2030	70.00	4.90	1.31

Table 22. Total Avoided Cost in Maryland per MW-day Saved for Measures Installed in 2016 (2012$/MW-day)

Year	Pepco, SMECO, & BGE	DPL	Potomac Edison
2016	$839.43	$56.79	$17.41
2017	727.23	50.51	13.19
2018	617.82	42.81	11.22
2019	525.46	36.35	9.56
2020	447.13	30.87	8.16
2021	380.01	26.29	6.95
2022	322.81	22.38	5.92
2023	274.43	19.03	5.05
2024	233.03	16.17	4.29
2025	198.10	13.75	3.66
2026	168.28	11.71	3.12
2027	142.90	9.95	2.65
2028	121.29	8.47	2.26
2029	103.02	7.20	1.93
2030	87.50	6.13	1.64

Table 23. Total Avoided Cost in Maryland per MW-day Saved for Measures Installed in 2017 (2012$/MW-day)

Year	Pepco, SMECO, & BGE	DPL	Potomac Edison
2017	$909.04	$63.14	$16.49
2018	772.27	53.52	14.02
2019	656.83	45.43	11.95
2020	558.92	38.58	10.20
2021	475.01	32.86	8.69
2022	403.51	27.98	7.40
2023	343.04	23.79	6.31
2024	291.28	20.21	5.37
2025	247.62	17.19	4.57
2026	210.35	14.63	3.90
2027	178.62	12.44	3.32
2028	151.62	10.58	2.83
2029	128.77	9.00	2.41
2030	109.37	7.66	2.05

7.4 DRIPE Issues

There are several issues related to the DRIPE calculations that warrant mention to ensure a full understanding of the limitations of these estimates. As noted previously, the energy and capacity DRIPE numbers are different for projects implemented in different years. The reason for this is that changes in load requirements affect the build-out of power plants (location, timing, and perhaps the type of plant constructed). As such, if we consider an energy conservation project implemented in 2015 that results in reductions in the demand for energy and the need for capacity for all following years, the underlying market infrastructure may be changed. Consequently, the same set of DRIPE numbers simply shifted forward to begin in a later year of project implementation is a simplification that may be better estimated through additional modeling. Further, given changes in underlying market factors (the price of natural gas, environmental regulations, changes in state RPS policies, additional announced power plant retirements, etc.), the avoided cost estimates would need to be periodically updated regardless of the approach employed.

The capacity DRIPE numbers, as noted above, are based on the estimated supply elasticities for the most recent PJM BRA, i.e., the BRA to secure capacity for the 2016/2017 delivery year. We would expect that the elasticities would change from year-to-year depending on a host of underlying factors, but no information on future elasticities is available. Periodic updating of the analysis would largely resolve this issue.

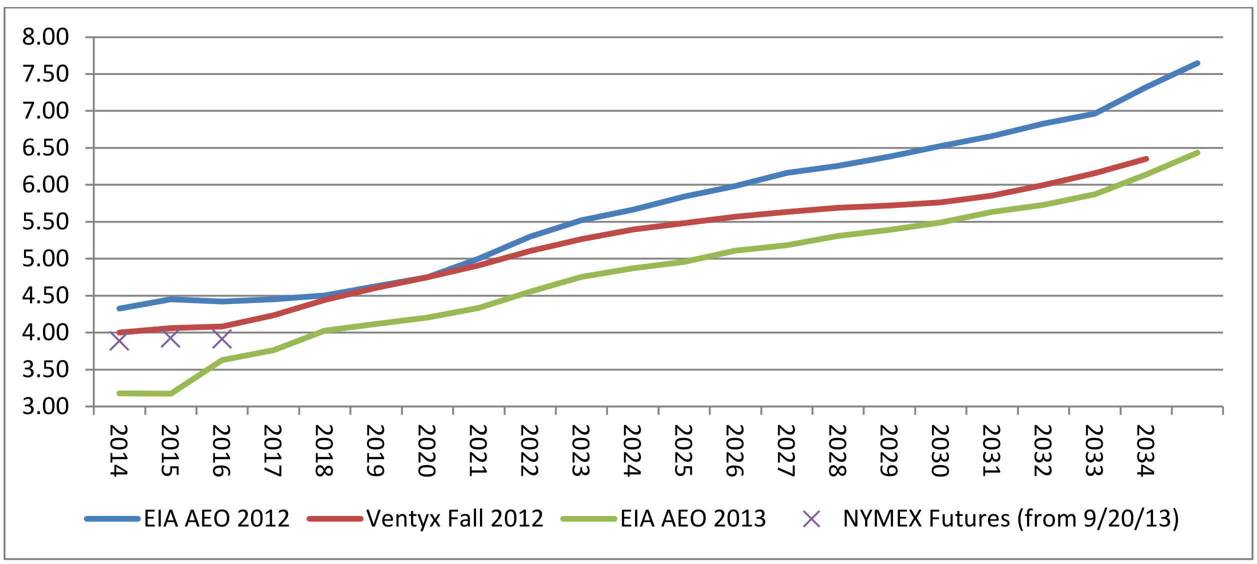
Finally, we note that some of the energy DRIPE numbers are negative, i.e., the implementation of an energy efficiency conservation project results in energy prices higher than before the project was implemented. This result occurred in several years in all three transmission zones. In general, negative DRIPE impacts associated with program implementation in a specific zone relate to changes in energy imports and exports between zones and the short-term elimination of the availability of lower cost power to serve load at the margin in that zone. However, for certain years in the PJM-APS and PJM-MidE transmission zones, a negative DRIPE is the result of a price increase in the PJM-SW zone, even as prices decrease in the zone with a modeled load reduction. This occurs because of the magnitude of consumers in Maryland that are located in PJM-SW relative to PJM-APS or PJM-MidE. This result is especially prominent, for example, in 2015 in PJM-APS during the on-peak period.

8. Natural Gas

Avoided natural gas costs are based on three components: projected Henry Hub (HH) wholesale gas prices; projected transmission costs; and projected distribution costs. Separate avoided natural gas costs are estimated for residential, commercial, and industrial customers in Maryland.

The HH price for 2013 is based on prices published in *Natural Gas Weekly*. Exeter selected one representative HH price for each month from January through October and averaged these values. HH price projections for 2014 through 2016 are based on the annual average value of monthly NYMEX futures. Projections of wholesale natural gas prices post-2016 are not based on futures prices due to a lack of liquidity in the wholesale markets for periods beyond a few years. For long-term HH price projections, Exeter considered three sources: the EIA's Annual Energy Outlook for 2012 (AEO 2012), AEO 2013, and the Ventyx Fall 2012 Reference Case natural gas price assumptions. Exeter compared these values through 2016 with average annual NYMEX values. As shown in Figure 13 below, the Ventyx values are closest to the short-term NYMEX futures.

Figure 13. Henry Hub Gas Price Comparison (2012$/MMBtu)



Based on this comparison, and because the Ventyx projections tend to be between the AEO 2012 and AEO 2013 projections, Exeter has opted to rely on Ventyx's projections of long-term wholesale natural gas prices. A straight-line bridge smooth's the transition between the NYMEX projection for 2016 and the Ventyx projection for 2019.

Transmission and distribution (T&D) costs are first projected together. These projections rely on historical T&D costs for Maryland residential, commercial, and industrial customers as a starting point. Because 2011 is the most recent year for which the EIA has retail prices on record for each sector, Exeter subtracted 2011 HH prices from these values to isolate Maryland-specific T&D costs.

These baseline T&D values are adjusted using regional growth rates derived from the AEO 2013 Mid-Atlantic Reference Case.[20] Once again, both recent and projected regional T&D costs are derived by subtracting HH prices from retail prices for each sector. Annual regional growth rates for T&D are then calculated and applied to the 2011 Maryland T&D costs to create a set of Maryland-specific T&D cost projections.

A final set of steps is used to distinguish between transmission and distribution cost projections. Regressing 16 years of historical Maryland citygate prices against historical HH prices establishes a strong linear relationship between the two (R^2=0.8389).[21] This relationship is used to project Maryland citygate prices based on projected HH prices. For each year, the difference between these two values is attributed to transmission. In turn, the difference between each yearly transmission cost projection and its corresponding T&D cost projection is then attributed to distribution (see Table 24 and Table 25, below).

[20] Maryland officially belongs to the AEO 2013's South Atlantic Region. However, the AEO's groupings are based on Census divisions, not commodity markets. At MEA's August 7, 2013 stakeholder meeting to review Exeter's plans for calculating avoided energy costs, the Maryland PSC Staff recommended using the Mid-Atlantic Reference Case, which includes New Jersey, New York, and Pennsylvania. Both MEA and Exeter concurred.
[21] Both data sets are available from the EIA. See http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_smd_a.htm for historical Maryland citygate prices and http://tonto.eia.gov/dnav/ng/hist/rngwhhda.htm for historical Henry Hub prices.

Table 24. Natural Gas Avoided Cost Components (2012$/MMBtu)

Year	Henry Hub	Transmission	Distribution Costs: Residential	Distribution Costs: Commercial	Distribution Costs: Industrial
2013	$3.56	$2.01	$6.20	$4.41	$1.30
2014	3.89	1.99	6.19	4.29	1.29
2015	3.92	1.99	6.03	4.14	1.32
2016	3.91	1.99	6.02	4.06	1.19
2017	4.14	1.98	6.12	4.10	1.19
2018	4.37	1.97	6.21	4.13	1.18
2019	4.61	1.96	6.29	4.16	1.19
2020	4.75	1.95	6.36	4.18	1.20
2021	4.91	1.94	6.36	4.12	1.10
2022	5.11	1.93	6.38	4.08	1.04
2023	5.26	1.92	6.39	4.03	0.98
2024	5.40	1.92	6.43	4.02	0.96
2025	5.48	1.91	6.47	4.00	0.93
2026	5.57	1.91	6.60	4.10	1.03
2027	5.63	1.91	6.60	4.04	0.96
2028	5.69	1.90	6.63	4.01	0.92
2029	5.72	1.90	6.69	4.02	0.92
2030	5.76	1.90	6.73	4.00	0.89

Table 25. Total Natural Gas Avoided Cost[22] (2012$/MMBtu)

Year	Residential	Commercial	Industrial
2013	$11.77	$9.98	$6.87
2014	12.07	10.17	7.17
2015	11.94	10.05	7.23
2016	11.92	9.96	7.09
2017	12.24	10.22	7.31
2018	12.55	10.47	7.52
2019	12.86	10.73	7.76
2020	13.06	10.88	7.90
2021	13.21	10.97	7.95
2022	13.42	11.12	8.08
2023	13.57	11.21	8.16
2024	13.75	11.34	8.28
2025	13.86	11.39	8.32
2026	14.08	11.58	8.51
2027	14.14	11.58	8.50
2028	14.22	11.60	8.51
2029	14.31	11.64	8.54
2030	14.39	11.66	8.55

[22] Total costs may differ from the sum of cost components due to rounding.

9. Propane and Distillate Fuel Oil

Propane and distillate fuel oil costs are drawn from the AEO 2013 Mid-Atlantic Reference Case. The avoided costs shown below in Table 26 are categorized by class of user: residential, commercial, and industrial.

Table 26. Propane and Distillate Fuel Oil Avoided Cost (2012$/MMBtu)

	Propane			Fuel Oil		
Year	Residential	Commercial	Industrial	Residential	Commercial	Industrial
2013	$26.46	$20.68	$19.39	$26.18	$25.11	$26.00
2014	25.91	20.07	18.78	26.08	23.03	23.43
2015	25.16	19.25	17.97	26.07	23.09	23.54
2016	25.27	19.37	18.08	26.45	23.48	23.94
2017	26.10	20.28	18.98	26.90	23.97	24.46
2018	26.62	20.87	19.57	27.25	24.37	24.89
2019	27.12	21.43	20.12	27.67	24.83	25.39
2020	27.59	21.96	20.65	28.05	25.18	25.72
2021	27.92	22.35	21.03	28.47	25.67	26.26
2022	28.29	22.77	21.45	28.88	26.19	26.86
2023	28.61	23.15	21.83	29.32	26.60	27.24
2024	28.90	23.48	22.16	29.77	27.02	27.65
2025	29.17	23.80	22.48	30.25	27.49	28.10
2026	29.44	24.12	22.80	30.69	27.90	28.49
2027	29.67	24.39	23.07	31.13	28.31	28.88
2028	29.89	24.65	23.33	31.59	28.73	29.28
2029	30.09	24.89	23.57	32.04	29.14	29.66
2030	30.29	25.13	23.81	32.46	29.52	30.00

10. Water and Wastewater

Avoided water-related costs include two components: water fees and wastewater fees. Costs after 2013 are projected for residential, commercial, and industrial customers. Costs for 2013 are based on fees charged by a representative water utility from each electric utility's service area. These pairings are shown below in Table 27.

Table 27. Electric Utility – Water Utility Pairings

Electric Utility	Representative Water and Wastewater Utility in Electric Utility's Service Region
BGE	City of Baltimore*
DPL	City of Salisbury**
Pepco/SMECO	Washington Suburban Sanitary Commission***
Potomac Edison	City of Hagerstown****

*2013 rates available at: http://publicworks.baltimorecity.gov/Bureaus/WaterWastewater/CustomerCare/Rates.aspx.
**2013 rates available at: http://www.ci.salisbury.md.us/?page_id=2203.
***2013 rates available at: http://www.wsscwater.com/home/jsp/content/rates.faces.
****2013 rates available at: http://www.hagerstownmd.org/index.aspx?NID=205.

Since water and wastewater charges are based on block rates (i.e., rates vary by usage levels), assumptions must be made about each customer class's water use. Residential customers are assumed to use 172 gallons per day, the average load for customers in Baltimore according to Baltimore City's Department of Public Works.[23] To estimate commercial and industrial water usage, Exeter reviewed average water use levels provided by non-Maryland water utilities. Commercial customers are assumed to use 10,000 gallons per day. This value lies between the amount of water used by a representative shopping mall and the amount used by a typical motel. Industrial customers are assumed to use 100,000 gallons per day. This value lies between the amount of water used by a typical college and the amount used by a light industrial facility.[24]

Water costs for all Maryland customers are assumed to grow at 1.5 times the projected annual rate of inflation, with the exception of Baltimore City.[25] The assumed growth rate is based on the *2012 Water and Wastewater Rate Survey*, a biannual survey of water and wastewater rates at over 200 U.S. utilities. According to the Survey, over the past 14 years, water and wastewater charges for residential customers using 1,000 cubic feet per month have

[23] "City of Baltimore Water and Wastewater Rates," http://publicworks.baltimorecity.gov/Bureaus/WaterWastewater/CustomerCare/Rates.aspx.
[24] For example, see Epcor, "Average Commercial Water Use," http://www.epcor.com/efficiency-conservation/small-business/Pages/commercial-water-use.aspx.
[25] Baltimore's Department of Public Works provides current rates, rates for FY 2015 (which begins 7/1/2014), and rates for FY 2016 (which begins 7/1/2015). In Table 28 and Table 29, Baltimore's current rate has been used for 2013 and 2014; the FY 2015 rate has been used for 2015; and the FY 2016 rate has been used for 2016. After this point, rates are assumed to rise at 1.5 times the projected annual rate of inflation.

increased by 4.90 percent and 5.19 percent annually, respectively, while the CPI has increased by 2.50 percent annually.[26] Residential water and wastewater rates nationwide, therefore, have grown at roughly two times the rate of inflation. A slightly lower growth rate is assumed to be a reasonable approximation for all customers in Maryland.[27] Estimated avoided water costs, based on these assumptions, are shown below in Table 28 (residential) and on the following page in Table 29 (commercial and industrial). The commercial avoided costs and the industrial avoided costs are the same since usage for the two categories of customers are contained in the same marginal rate block.

Table 28. Avoided Cost of Water and Wastewater for Residential Customers
Assumed Usage – 172 Gallons per Day
(2012$/1,000 gallons)

	Service Region			
Year	BGE	DPL	Pepco/ SMECO	Potomac Edison
2013	$11.35	$4.84	$10.26	$5.74
2014	11.65	4.97	10.54	5.89
2015	12.02	5.13	10.87	6.08
2016	12.40	5.29	11.21	6.27
2017	12.79	5.46	11.56	6.47
2018	13.19	5.63	11.93	6.67
2019	13.61	5.81	12.30	6.88
2020	14.04	5.99	12.69	7.10
2021	14.48	6.18	13.09	7.32
2022	14.93	6.38	13.50	7.55
2023	15.41	6.58	13.93	7.79
2024	15.89	6.78	14.37	8.04
2025	16.39	7.00	14.82	8.29
2026	16.91	7.22	15.29	8.55
2027	17.44	7.44	15.77	8.82
2028	17.99	7.68	16.26	9.10
2029	18.56	7.92	16.78	9.39
2030	19.14	8.17	17.30	9.68

[26] Raftelis Consulting, Inc. and the American Water Works Association, *2012 Water and Wastewater Rate Survey Highlights and Observations*, February 2013, www.awwa.org/portals/0/files/publications/documents/samples/2012waterandwastewaterratesurvey.pdf.
[27] National averages include states in the West, where water scarcity tends to drive prices up more quickly than in the country as a whole.

Table 29. Avoided Cost of Water and Wastewater for Commercial and Industrial Customers
Assumed Usage – 10,000-100,000 Gallons per Day
(2012$/1,000 gallons)

	Service Region			
Year	BGE	DPL	Pepco/ SMECO	Potomac Edison
2013	$8.55	$2.26	$16.79	$5.56
2014	8.78	2.33	17.24	5.71
2015	9.06	2.40	17.78	5.89
2016	9.35	2.47	18.34	6.08
2017	9.64	2.55	18.92	6.27
2018	9.94	2.63	19.52	6.47
2019	10.26	2.72	20.13	6.67
2020	10.58	2.80	20.76	6.88
2021	10.91	2.89	21.42	7.10
2022	11.26	2.98	22.09	7.32
2023	11.61	3.07	22.79	7.55
2024	11.98	3.17	23.51	7.79
2025	12.35	3.27	24.25	8.04
2026	12.74	3.37	25.01	8.29
2027	13.15	3.48	25.80	8.55
2028	13.56	3.59	26.61	8.82
2029	13.99	3.70	27.45	9.10
2030	14.43	3.82	28.32	9.38

11. Results of the Avoided Cost Analysis

Results are compiled into two categories: regional (i.e., utility-specific) avoided costs associated with electricity and water/wastewater, and Maryland-wide avoided energy costs for other fuels. The regional avoided cost components include electric energy, electric generating capacity, renewable energy, T&D, DRIPE, and water and wastewater. The avoided costs of other fuels are differentiated by customer class and include natural gas, propane, and fuel oil. All avoided costs are presented in constant 2012 dollars in this section. Avoided costs in nominal terms are included in the appendix.

11.1 Regional Avoided Costs

Utility-specific avoided costs associated with electricity and water/wastewater are presented in the tables below. As explained in the DRIPE chapter, DRIPE differs depending upon when an energy efficiency or demand reduction measure is installed. Thus, there are three tables for each investor-owned utility in Maryland—one for each implementation year included in this analysis (2015, 2016, and 2017).

Table 30. Avoided Cost per Unit Reduced in the Pepco Maryland and SMECO Service Territory, 2015 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	69.66	38.18	59.82	45.10	229.81	1.44	68.49	N/A	N/A	N/A	10.26	16.79
2014	63.83	45.92	55.55	48.42	209.33	1.83	68.49	N/A	N/A	N/A	10.54	17.24
2015	77.53	46.89	56.66	49.47	182.27	1.98	68.49	13.26	1.83	940.08	10.87	17.78
2016	86.50	48.11	59.54	49.39	160.86	2.61	68.49	8.18	1.61	671.54	11.21	18.34
2017	86.22	46.75	58.46	48.31	172.63	2.99	68.49	4.48	1.28	581.79	11.56	18.92
2018	84.42	46.25	58.34	47.65	182.06	3.90	68.49	2.11	0.98	494.25	11.93	19.52
2019	83.35	45.72	57.80	47.11	192.00	4.51	68.49	1.76	0.83	420.37	12.30	20.13
2020	82.73	45.13	57.33	48.21	202.48	4.10	68.49	0.03	0.66	357.71	12.69	20.76
2021	82.31	45.65	58.11	47.22	213.54	3.78	68.49	0.22	0.33	304.01	13.09	21.42
2022	83.17	46.71	59.45	49.60	225.20	3.55	68.49	(0.37)	0.14	258.25	13.50	22.09
2023	84.18	47.88	59.92	49.69	237.50	2.82	68.49	0.29	0.02	219.55	13.93	22.79
2024	83.22	48.55	60.54	51.31	250.47	2.48	68.49	0.13	0.12	186.42	14.37	23.51
2025	83.94	51.93	60.33	51.41	264.15	2.02	68.49	0.20	0.15	158.48	14.82	24.25
2026	84.60	52.87	61.23	51.33	278.58	1.70	68.49	0.00	0.15	134.62	15.29	25.01
2027	84.43	50.02	61.55	51.72	293.79	1.27	68.49	0.01	0.09	114.32	15.77	25.80
2028	85.43	50.97	61.91	52.35	309.83	0.94	68.49	(0.04)	0.05	97.03	16.26	26.61
2029	86.12	50.91	62.33	52.66	326.75	0.59	68.49	0.04	0.04	82.41	16.78	27.45
2030	86.07	51.42	63.25	53.18	344.60	0.51	68.49	0.00	0.04	70.00	17.30	28.32

Table 31. Avoided Cost per Unit Reduced in the Pepco Maryland and SMECO Service Territory, 2016 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	69.66	38.18	59.82	45.10	229.81	1.44	68.49	N/A	N/A	N/A	10.26	16.79
2014	63.83	45.92	55.55	48.42	209.33	1.83	68.49	N/A	N/A	N/A	10.54	17.24
2015	77.53	46.89	56.66	49.47	182.27	1.98	68.49	N/A	N/A	N/A	10.87	17.78
2016	86.50	48.11	59.54	49.39	160.86	2.61	68.49	10.22	2.01	839.43	11.21	18.34
2017	86.22	46.75	58.46	48.31	172.63	2.99	68.49	5.60	1.60	727.23	11.56	18.92
2018	84.42	46.25	58.34	47.65	182.06	3.90	68.49	2.64	1.23	617.82	11.93	19.52
2019	83.35	45.72	57.80	47.11	192.00	4.51	68.49	2.20	1.04	525.46	12.30	20.13
2020	82.73	45.13	57.33	48.21	202.48	4.10	68.49	0.04	0.83	447.13	12.69	20.76
2021	82.31	45.65	58.11	47.22	213.54	3.78	68.49	0.27	0.41	380.01	13.09	21.42
2022	83.17	46.71	59.45	49.60	225.20	3.55	68.49	(0.46)	0.17	322.81	13.50	22.09
2023	84.18	47.88	59.92	49.69	237.50	2.82	68.49	0.36	0.02	274.43	13.93	22.79
2024	83.22	48.55	60.54	51.31	250.47	2.48	68.49	0.16	0.15	233.03	14.37	23.51
2025	83.94	51.93	60.33	51.41	264.15	2.02	68.49	0.26	0.18	198.10	14.82	24.25
2026	84.60	52.87	61.23	51.33	278.58	1.70	68.49	(0.01)	0.18	168.28	15.29	25.01
2027	84.43	50.02	61.55	51.72	293.79	1.27	68.49	0.02	0.12	142.90	15.77	25.80
2028	85.43	50.97	61.91	52.35	309.83	0.94	68.49	(0.05)	0.06	121.29	16.26	26.61
2029	86.12	50.91	62.33	52.66	326.75	0.59	68.49	0.05	0.05	103.02	16.78	27.45
2030	86.07	51.42	63.25	53.18	344.60	0.51	68.49	0.00	0.05	87.50	17.30	28.32

Table 32. Avoided Cost per Unit Reduced in the Pepco Maryland and SMECO Service Territory, 2017 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	69.66	38.18	59.82	45.10	229.81	1.44	68.49	N/A	N/A	N/A	10.26	16.79
2014	63.83	45.92	55.55	48.42	209.33	1.83	68.49	N/A	N/A	N/A	10.54	17.24
2015	77.53	46.89	56.66	49.47	182.27	1.98	68.49	N/A	N/A	N/A	10.87	17.78
2016	86.50	48.11	59.54	49.39	160.86	2.61	68.49	N/A	N/A	N/A	11.21	18.34
2017	86.22	46.75	58.46	48.31	172.63	2.99	68.49	8.69	1.71	909.04	11.56	18.92
2018	84.42	46.25	58.34	47.65	182.06	3.90	68.49	4.76	1.36	772.27	11.93	19.52
2019	83.35	45.72	57.80	47.11	192.00	4.51	68.49	2.24	1.04	656.83	12.30	20.13
2020	82.73	45.13	57.33	48.21	202.48	4.10	68.49	1.87	0.88	558.92	12.69	20.76
2021	82.31	45.65	58.11	47.22	213.54	3.78	68.49	0.04	0.70	475.01	13.09	21.42
2022	83.17	46.71	59.45	49.60	225.20	3.55	68.49	0.23	0.35	403.51	13.50	22.09
2023	84.18	47.88	59.92	49.69	237.50	2.82	68.49	(0.39)	0.15	343.04	13.93	22.79
2024	83.22	48.55	60.54	51.31	250.47	2.48	68.49	0.31	0.02	291.28	14.37	23.51
2025	83.94	51.93	60.33	51.41	264.15	2.02	68.49	0.14	0.12	247.62	14.82	24.25
2026	84.60	52.87	61.23	51.33	278.58	1.70	68.49	0.22	0.16	210.35	15.29	25.01
2027	84.43	50.02	61.55	51.72	293.79	1.27	68.49	(0.01)	0.16	178.62	15.77	25.80
2028	85.43	50.97	61.91	52.35	309.83	0.94	68.49	0.02	0.10	151.62	16.26	26.61
2029	86.12	50.91	62.33	52.66	326.75	0.59	68.49	(0.04)	0.05	128.77	16.78	27.45
2030	86.07	51.42	63.25	53.18	344.60	0.51	68.49	0.05	0.04	109.37	17.30	28.32

Table 33. Avoided Cost per Unit Reduced in the BGE Service Territory, 2015 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	68.21	37.39	58.58	44.16	229.81	1.44	93.49	N/A	N/A	N/A	11.35	8.55
2014	62.51	44.96	54.40	47.42	209.33	1.83	93.49	N/A	N/A	N/A	11.65	8.78
2015	75.91	45.92	55.48	48.44	182.27	1.98	93.49	13.26	1.83	940.08	12.02	9.06
2016	84.70	47.11	58.30	48.37	160.86	2.61	93.49	8.18	1.61	671.54	12.40	9.35
2017	84.42	45.78	57.25	47.31	172.63	2.99	93.49	4.48	1.28	581.79	12.79	9.64
2018	82.66	45.29	57.13	46.66	182.06	3.90	93.49	2.11	0.98	494.25	13.19	9.94
2019	81.62	44.77	56.60	46.13	192.00	4.51	93.49	1.76	0.83	420.37	13.61	10.26
2020	81.01	44.19	56.13	47.21	202.48	4.10	93.49	0.03	0.66	357.71	14.04	10.58
2021	80.60	44.70	56.90	46.24	213.54	3.78	93.49	0.22	0.33	304.01	14.48	10.91
2022	81.44	45.74	58.21	48.57	225.20	3.55	93.49	(0.37)	0.14	258.25	14.93	11.26
2023	82.43	46.88	58.68	48.65	237.50	2.82	93.49	0.29	0.02	219.55	15.41	11.61
2024	81.49	47.54	59.28	50.24	250.47	2.48	93.49	0.13	0.12	186.42	15.89	11.98
2025	82.19	50.85	59.07	50.34	264.15	2.02	93.49	0.20	0.15	158.48	16.39	12.35
2026	82.84	51.77	59.95	50.26	278.58	1.70	93.49	0.00	0.15	134.62	16.91	12.74
2027	82.67	48.98	60.27	50.64	293.79	1.27	93.49	0.01	0.09	114.32	17.44	13.15
2028	83.66	49.91	60.63	51.26	309.83	0.94	93.49	(0.04)	0.05	97.03	17.99	13.56
2029	84.33	49.85	61.04	51.56	326.75	0.59	93.49	0.04	0.04	82.41	18.56	13.99
2030	84.28	50.35	61.93	52.07	344.60	0.51	93.49	0.00	0.04	70.00	19.14	14.43

Table 34. Avoided Cost per Unit Reduced in the BGE Service Territory, 2016 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	68.21	37.39	58.58	44.16	229.81	1.44	93.49	N/A	N/A	N/A	11.35	8.55
2014	62.51	44.96	54.40	47.42	209.33	1.83	93.49	N/A	N/A	N/A	11.65	8.78
2015	75.91	45.92	55.48	48.44	182.27	1.98	93.49	N/A	N/A	N/A	12.02	9.06
2016	84.70	47.11	58.30	48.37	160.86	2.61	93.49	10.22	2.01	839.43	12.40	9.35
2017	84.42	45.78	57.25	47.31	172.63	2.99	93.49	5.60	1.60	727.23	12.79	9.64
2018	82.66	45.29	57.13	46.66	182.06	3.90	93.49	2.64	1.23	617.82	13.19	9.94
2019	81.62	44.77	56.60	46.13	192.00	4.51	93.49	2.20	1.04	525.46	13.61	10.26
2020	81.01	44.19	56.13	47.21	202.48	4.10	93.49	0.04	0.83	447.13	14.04	10.58
2021	80.60	44.70	56.90	46.24	213.54	3.78	93.49	0.27	0.41	380.01	14.48	10.91
2022	81.44	45.74	58.21	48.57	225.20	3.55	93.49	(0.46)	0.17	322.81	14.93	11.26
2023	82.43	46.88	58.68	48.65	237.50	2.82	93.49	0.36	0.02	274.43	15.41	11.61
2024	81.49	47.54	59.28	50.24	250.47	2.48	93.49	0.16	0.15	233.03	15.89	11.98
2025	82.19	50.85	59.07	50.34	264.15	2.02	93.49	0.26	0.18	198.10	16.39	12.35
2026	82.84	51.77	59.95	50.26	278.58	1.70	93.49	(0.01)	0.18	168.28	16.91	12.74
2027	82.67	48.98	60.27	50.64	293.79	1.27	93.49	0.02	0.12	142.90	17.44	13.15
2028	83.66	49.91	60.63	51.26	309.83	0.94	93.49	(0.05)	0.06	121.29	17.99	13.56
2029	84.33	49.85	61.04	51.56	326.75	0.59	93.49	0.05	0.05	103.02	18.56	13.99
2030	84.28	50.35	61.93	52.07	344.60	0.51	93.49	0.00	0.05	87.50	19.14	14.43

Table 35. Avoided Cost per Unit Reduced in the BGE Service Territory, 2017 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	68.21	37.39	58.58	44.16	229.81	1.44	93.49	N/A	N/A	N/A	11.35	8.55
2014	62.51	44.96	54.40	47.42	209.33	1.83	93.49	N/A	N/A	N/A	11.65	8.78
2015	75.91	45.92	55.48	48.44	182.27	1.98	93.49	N/A	N/A	N/A	12.02	9.06
2016	84.70	47.11	58.30	48.37	160.86	2.61	93.49	N/A	N/A	N/A	12.40	9.35
2017	84.42	45.78	57.25	47.31	172.63	2.99	93.49	8.69	1.71	909.04	12.79	9.64
2018	82.66	45.29	57.13	46.66	182.06	3.90	93.49	4.76	1.36	772.27	13.19	9.94
2019	81.62	44.77	56.60	46.13	192.00	4.51	93.49	2.24	1.04	656.83	13.61	10.26
2020	81.01	44.19	56.13	47.21	202.48	4.10	93.49	1.87	0.88	558.92	14.04	10.58
2021	80.60	44.70	56.90	46.24	213.54	3.78	93.49	0.04	0.70	475.01	14.48	10.91
2022	81.44	45.74	58.21	48.57	225.20	3.55	93.49	0.23	0.35	403.51	14.93	11.26
2023	82.43	46.88	58.68	48.65	237.50	2.82	93.49	(0.39)	0.15	343.04	15.41	11.61
2024	81.49	47.54	59.28	50.24	250.47	2.48	93.49	0.31	0.02	291.28	15.89	11.98
2025	82.19	50.85	59.07	50.34	264.15	2.02	93.49	0.14	0.12	247.62	16.39	12.35
2026	82.84	51.77	59.95	50.26	278.58	1.70	93.49	0.22	0.16	210.35	16.91	12.74
2027	82.67	48.98	60.27	50.64	293.79	1.27	93.49	(0.01)	0.16	178.62	17.44	13.15
2028	83.66	49.91	60.63	51.26	309.83	0.94	93.49	0.02	0.10	151.62	17.99	13.56
2029	84.33	49.85	61.04	51.56	326.75	0.59	93.49	(0.04)	0.05	128.77	18.56	13.99
2030	84.28	50.35	61.93	52.07	344.60	0.51	93.49	0.05	0.04	109.37	19.14	14.43

Table 36. Avoided Cost per Unit Reduced in the DPL Maryland Service Territory, 2015 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	71.09	39.65	55.64	43.05	246.54	1.44	68.49	N/A	N/A	N/A	4.84	2.26
2014	69.76	45.25	56.25	48.21	218.78	1.83	68.49	N/A	N/A	N/A	4.97	2.33
2015	83.49	46.82	57.63	47.85	182.27	1.98	68.49	5.70	1.39	63.44	5.13	2.40
2016	91.43	47.79	60.14	49.11	160.86	2.61	68.49	3.63	1.36	45.43	5.29	2.47
2017	91.26	46.54	59.26	48.12	177.38	2.99	68.49	4.14	1.10	40.41	5.46	2.55
2018	87.41	46.02	58.79	47.39	187.07	3.90	68.49	2.23	0.86	34.25	5.63	2.63
2019	85.19	45.29	58.13	46.67	197.29	4.51	68.49	1.83	0.61	29.08	5.81	2.72
2020	83.80	44.82	57.84	46.31	208.06	4.10	68.49	0.65	0.50	24.69	5.99	2.80
2021	83.48	45.31	58.73	46.97	219.42	3.78	68.49	(0.13)	0.26	21.03	6.18	2.89
2022	83.64	46.48	59.70	48.06	231.40	3.55	68.49	(0.28)	0.14	17.91	6.38	2.98
2023	84.66	47.85	60.51	49.68	244.04	2.82	68.49	(0.25)	(0.01)	15.23	6.58	3.07
2024	83.33	48.48	61.38	50.15	257.37	2.48	68.49	(0.07)	(0.03)	12.93	6.78	3.17
2025	83.41	48.52	61.00	50.53	271.42	2.02	68.49	(0.24)	(0.05)	11.00	7.00	3.27
2026	83.77	49.72	62.02	51.60	286.25	1.70	68.49	(0.38)	(0.05)	9.37	7.22	3.37
2027	84.10	50.25	62.30	51.93	301.88	1.27	68.49	(0.26)	(0.04)	7.96	7.44	3.48
2028	84.40	51.26	62.89	52.92	318.36	0.94	68.49	(0.19)	(0.03)	6.77	7.68	3.59
2029	86.47	51.54	63.62	53.71	335.75	0.59	68.49	(0.08)	(0.02)	5.76	7.92	3.70
2030	84.30	51.83	63.89	54.04	354.08	0.51	68.49	(0.09)	(0.01)	4.90	8.17	3.82

Table 37. Avoided Cost per Unit Reduced in the DPL Maryland Service Territory, 2016 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	71.09	39.65	55.64	43.05	246.54	1.44	68.49	N/A	N/A	N/A	4.84	2.26
2014	69.76	45.25	56.25	48.21	218.78	1.83	68.49	N/A	N/A	N/A	4.97	2.33
2015	83.49	46.82	57.63	47.85	182.27	1.98	68.49	N/A	N/A	N/A	5.13	2.40
2016	91.43	47.79	60.14	49.11	160.86	2.61	68.49	4.54	1.70	56.79	5.29	2.47
2017	91.26	46.54	59.26	48.12	177.38	2.99	68.49	5.18	1.38	50.51	5.46	2.55
2018	87.41	46.02	58.79	47.39	187.07	3.90	68.49	2.78	1.07	42.81	5.63	2.63
2019	85.19	45.29	58.13	46.67	197.29	4.51	68.49	2.28	0.76	36.35	5.81	2.72
2020	83.80	44.82	57.84	46.31	208.06	4.10	68.49	0.81	0.63	30.87	5.99	2.80
2021	83.48	45.31	58.73	46.97	219.42	3.78	68.49	(0.16)	0.32	26.29	6.18	2.89
2022	83.64	46.48	59.70	48.06	231.40	3.55	68.49	(0.35)	0.17	22.38	6.38	2.98
2023	84.66	47.85	60.51	49.68	244.04	2.82	68.49	(0.31)	(0.02)	19.03	6.58	3.07
2024	83.33	48.48	61.38	50.15	257.37	2.48	68.49	(0.09)	(0.04)	16.17	6.78	3.17
2025	83.41	48.52	61.00	50.53	271.42	2.02	68.49	(0.31)	(0.07)	13.75	7.00	3.27
2026	83.77	49.72	62.02	51.60	286.25	1.70	68.49	(0.47)	(0.06)	11.71	7.22	3.37
2027	84.10	50.25	62.30	51.93	301.88	1.27	68.49	(0.33)	(0.05)	9.95	7.44	3.48
2028	84.40	51.26	62.89	52.92	318.36	0.94	68.49	(0.24)	(0.04)	8.47	7.68	3.59
2029	86.47	51.54	63.62	53.71	335.75	0.59	68.49	(0.11)	(0.02)	7.20	7.92	3.70
2030	84.30	51.83	63.89	54.04	354.08	0.51	68.49	(0.11)	(0.02)	6.13	8.17	3.82

Table 38. Avoided Cost per Unit Reduced in the DPL Maryland Service Territory, 2017 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	71.09	39.65	55.64	43.05	246.54	1.44	68.49	N/A	N/A	N/A	4.84	2.26
2014	69.76	45.25	56.25	48.21	218.78	1.83	68.49	N/A	N/A	N/A	4.97	2.33
2015	83.49	46.82	57.63	47.85	182.27	1.98	68.49	N/A	N/A	N/A	5.13	2.40
2016	91.43	47.79	60.14	49.11	160.86	2.61	68.49	N/A	N/A	N/A	5.29	2.47
2017	91.26	46.54	59.26	48.12	177.38	2.99	68.49	3.86	1.44	63.14	5.46	2.55
2018	87.41	46.02	58.79	47.39	187.07	3.90	68.49	4.40	1.17	53.52	5.63	2.63
2019	85.19	45.29	58.13	46.67	197.29	4.51	68.49	2.37	0.91	45.43	5.81	2.72
2020	83.80	44.82	57.84	46.31	208.06	4.10	68.49	1.94	0.65	38.58	5.99	2.80
2021	83.48	45.31	58.73	46.97	219.42	3.78	68.49	0.69	0.53	32.86	6.18	2.89
2022	83.64	46.48	59.70	48.06	231.40	3.55	68.49	(0.14)	0.28	27.98	6.38	2.98
2023	84.66	47.85	60.51	49.68	244.04	2.82	68.49	(0.30)	0.15	23.79	6.58	3.07
2024	83.33	48.48	61.38	50.15	257.37	2.48	68.49	(0.27)	(0.01)	20.21	6.78	3.17
2025	83.41	48.52	61.00	50.53	271.42	2.02	68.49	(0.07)	(0.03)	17.19	7.00	3.27
2026	83.77	49.72	62.02	51.60	286.25	1.70	68.49	(0.26)	(0.06)	14.63	7.22	3.37
2027	84.10	50.25	62.30	51.93	301.88	1.27	68.49	(0.40)	(0.05)	12.44	7.44	3.48
2028	84.40	51.26	62.89	52.92	318.36	0.94	68.49	(0.28)	(0.04)	10.58	7.68	3.59
2029	86.47	51.54	63.62	53.71	335.75	0.59	68.49	(0.20)	(0.04)	9.00	7.92	3.70
2030	84.30	51.83	63.89	54.04	354.08	0.51	68.49	(0.09)	(0.02)	7.66	8.17	3.82

Table 39. Avoided Cost per Unit Reduced in the Potomac Edison Maryland Service Territory, 2015 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	60.42	35.77	51.53	40.64	28.23	1.44	68.49	N/A	N/A	N/A	5.74	5.56
2014	58.98	40.67	51.40	42.46	102.40	1.83	68.49	N/A	N/A	N/A	5.89	5.71
2015	68.63	45.41	54.66	45.78	155.46	1.98	68.49	(1.72)	1.88	25.23	6.08	5.89
2016	75.37	46.58	57.43	47.75	105.45	2.61	68.49	1.55	1.79	13.93	6.27	6.08
2017	75.73	45.24	56.56	46.75	98.69	2.99	68.49	5.52	2.15	10.55	6.47	6.27
2018	74.69	44.56	56.51	46.12	104.08	3.90	68.49	5.14	1.71	8.97	6.67	6.47
2019	75.30	43.89	56.00	45.54	109.76	4.51	68.49	3.04	1.51	7.65	6.88	6.67
2020	75.32	43.34	55.51	44.91	115.76	4.10	68.49	0.59	0.78	6.53	7.10	6.88
2021	76.42	43.69	56.34	45.63	122.08	3.78	68.49	0.99	0.59	5.56	7.32	7.10
2022	78.24	44.76	57.61	46.14	128.75	3.55	68.49	1.36	0.36	4.74	7.55	7.32
2023	78.26	45.34	58.08	47.70	135.78	2.82	68.49	1.05	0.25	4.04	7.79	7.55
2024	77.96	45.92	58.65	47.76	143.19	2.48	68.49	0.81	0.21	3.43	8.04	7.79
2025	78.17	45.12	58.47	48.20	151.01	2.02	68.49	0.57	0.17	2.92	8.29	8.04
2026	78.45	46.09	59.17	49.09	159.26	1.70	68.49	0.20	0.16	2.49	8.55	8.29
2027	78.44	47.41	59.43	49.58	167.96	1.27	68.49	0.09	0.12	2.12	8.82	8.55
2028	79.37	48.11	59.80	50.17	177.13	0.94	68.49	(0.28)	0.03	1.81	9.10	8.82
2029	78.96	48.39	60.17	50.48	186.80	0.59	68.49	(0.25)	(0.01)	1.54	9.39	9.10
2030	80.38	48.87	60.95	50.79	197.00	0.51	68.49	(0.34)	(0.03)	1.31	9.68	9.38

Table 40. Avoided Cost per Unit Reduced in the Potomac Edison Maryland Service Territory, 2016 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	60.42	35.77	51.53	40.64	28.23	1.44	68.49	N/A	N/A	N/A	5.74	5.56
2014	58.98	40.67	51.40	42.46	102.40	1.83	68.49	N/A	N/A	N/A	5.89	5.71
2015	68.63	45.41	54.66	45.78	155.46	1.98	68.49	N/A	N/A	N/A	6.08	5.89
2016	75.37	46.58	57.43	47.75	105.45	2.61	68.49	1.94	2.24	17.41	6.27	6.08
2017	75.73	45.24	56.56	46.75	98.69	2.99	68.49	6.90	2.69	13.19	6.47	6.27
2018	74.69	44.56	56.51	46.12	104.08	3.90	68.49	6.42	2.14	11.22	6.67	6.47
2019	75.30	43.89	56.00	45.54	109.76	4.51	68.49	3.80	1.89	9.56	6.88	6.67
2020	75.32	43.34	55.51	44.91	115.76	4.10	68.49	0.74	0.97	8.16	7.10	6.88
2021	76.42	43.69	56.34	45.63	122.08	3.78	68.49	1.23	0.73	6.95	7.32	7.10
2022	78.24	44.76	57.61	46.14	128.75	3.55	68.49	1.70	0.45	5.92	7.55	7.32
2023	78.26	45.34	58.08	47.70	135.78	2.82	68.49	1.32	0.32	5.05	7.79	7.55
2024	77.96	45.92	58.65	47.76	143.19	2.48	68.49	1.01	0.26	4.29	8.04	7.79
2025	78.17	45.12	58.47	48.20	151.01	2.02	68.49	0.72	0.21	3.66	8.29	8.04
2026	78.45	46.09	59.17	49.09	159.26	1.70	68.49	0.25	0.20	3.12	8.55	8.29
2027	78.44	47.41	59.43	49.58	167.96	1.27	68.49	0.11	0.14	2.65	8.82	8.55
2028	79.37	48.11	59.80	50.17	177.13	0.94	68.49	(0.35)	0.04	2.26	9.10	8.82
2029	78.96	48.39	60.17	50.48	186.80	0.59	68.49	(0.31)	(0.02)	1.93	9.39	9.10
2030	80.38	48.87	60.95	50.79	197.00	0.51	68.49	(0.42)	(0.04)	1.64	9.68	9.38

Table 41. Avoided Cost per Unit Reduced in the Potomac Edison Maryland Service Territory, 2017 DRIPE (2012$)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	60.42	35.77	51.53	40.64	28.23	1.44	68.49	N/A	N/A	N/A	5.74	5.56
2014	58.98	40.67	51.40	42.46	102.40	1.83	68.49	N/A	N/A	N/A	5.89	5.71
2015	68.63	45.41	54.66	45.78	155.46	1.98	68.49	N/A	N/A	N/A	6.08	5.89
2016	75.37	46.58	57.43	47.75	105.45	2.61	68.49	N/A	N/A	N/A	6.27	6.08
2017	75.73	45.24	56.56	46.75	98.69	2.99	68.49	1.65	1.90	16.49	6.47	6.27
2018	74.69	44.56	56.51	46.12	104.08	3.90	68.49	5.87	2.29	14.02	6.67	6.47
2019	75.30	43.89	56.00	45.54	109.76	4.51	68.49	5.46	1.82	11.95	6.88	6.67
2020	75.32	43.34	55.51	44.91	115.76	4.10	68.49	3.23	1.60	10.20	7.10	6.88
2021	76.42	43.69	56.34	45.63	122.08	3.78	68.49	0.63	0.83	8.69	7.32	7.10
2022	78.24	44.76	57.61	46.14	128.75	3.55	68.49	1.05	0.62	7.40	7.55	7.32
2023	78.26	45.34	58.08	47.70	135.78	2.82	68.49	1.45	0.38	6.31	7.79	7.55
2024	77.96	45.92	58.65	47.76	143.19	2.48	68.49	1.12	0.27	5.37	8.04	7.79
2025	78.17	45.12	58.47	48.20	151.01	2.02	68.49	0.86	0.22	4.57	8.29	8.04
2026	78.45	46.09	59.17	49.09	159.26	1.70	68.49	0.61	0.18	3.90	8.55	8.29
2027	78.44	47.41	59.43	49.58	167.96	1.27	68.49	0.22	0.17	3.32	8.82	8.55
2028	79.37	48.11	59.80	50.17	177.13	0.94	68.49	0.09	0.12	2.83	9.10	8.82
2029	78.96	48.39	60.17	50.48	186.80	0.59	68.49	(0.30)	0.04	2.41	9.39	9.10
2030	80.38	48.87	60.95	50.79	197.00	0.51	68.49	(0.26)	(0.01)	2.05	9.68	9.38

11.2 Avoided Cost of Other Fuels in Maryland

In addition to avoided electricity costs, energy efficiency measures can reduce the consumption of other fuels, including natural gas, propane, and distillate fuel oil. The delivered costs for these fuels vary by customer class, and avoided cost estimates are presented in the following tables for residential, commercial, and industrial customers.

Table 42. Avoided Cost of Other Fuels for Residential Customers (2012$/MMBtu)

Year	Natural Gas	Propane	Fuel Oil
2013	$11.77	$26.46	$26.18
2014	12.07	25.91	26.08
2015	11.94	25.16	26.07
2016	11.92	25.27	26.45
2017	12.24	26.10	26.90
2018	12.55	26.62	27.25
2019	12.86	27.12	27.67
2020	13.06	27.59	28.05
2021	13.21	27.92	28.47
2022	13.42	28.29	28.88
2023	13.57	28.61	29.32
2024	13.75	28.90	29.77
2025	13.86	29.17	30.25
2026	14.08	29.44	30.69
2027	14.14	29.67	31.13
2028	14.22	29.89	31.59
2029	14.31	30.09	32.04
2030	14.39	30.29	32.46

Table 43. Avoided Cost of Other Fuels for Commercial Customers (2012$/MMBtu)

Year	Natural Gas	Propane	Fuel Oil
2013	$9.98	$20.68	$25.11
2014	10.17	20.07	23.03
2015	10.05	19.25	23.09
2016	9.96	19.37	23.48
2017	10.22	20.28	23.97
2018	10.47	20.87	24.37
2019	10.73	21.43	24.83
2020	10.88	21.96	25.18
2021	10.97	22.35	25.67
2022	11.12	22.77	26.19
2023	11.21	23.15	26.60
2024	11.34	23.48	27.02
2025	11.39	23.80	27.49
2026	11.58	24.12	27.90
2027	11.58	24.39	28.31
2028	11.60	24.65	28.73
2029	11.64	24.89	29.14
2030	11.66	25.13	29.52

Table 44. Avoided Cost of Other Fuels for Industrial Customers (2012$/MMBtu)

Year	Natural Gas	Propane	Fuel Oil
2013	$6.87	$19.39	$26.00
2014	7.17	18.78	23.43
2015	7.23	17.97	23.54
2016	7.09	18.08	23.94
2017	7.31	18.98	24.46
2018	7.52	19.57	24.89
2019	7.76	20.12	25.39
2020	7.90	20.65	25.72
2021	7.95	21.03	26.26
2022	8.08	21.45	26.86
2023	8.16	21.83	27.24
2024	8.28	22.16	27.65
2025	8.32	22.48	28.10
2026	8.51	22.80	28.49
2027	8.50	23.07	28.88
2028	8.51	23.33	29.28
2029	8.54	23.57	29.66
2030	8.55	23.81	30.00

Appendix 1. Avoided Emissions and Emissions Allowance Costs

The avoided costs of emissions compliance are not separately calculated in the body of this report because they are embodied in the avoided energy costs. The price of electricity includes the costs that generators incur to comply with federal and state emissions statutes and regulations. To provide additional and potentially useful information to stakeholders, Table 45 below provides the emissions allowance prices embedded in the Ventyx model and used to compute the electric energy prices. Prices for SO_2 and NO_x emissions are based on the Clean Air Interstate Rule (CAIR), and CO_2 prices reflect the current RGGI cap for CO_2. As noted in the report, states participating in RGGI voted in 2013 to reduce the RGGI CO_2 cap by 45 percent. Most states are already in compliance with CAIR, resulting in depressed prices for SO_2 and NO_x relative to historical data.[28]

Table 45. Projected Emissions Allowance Prices (2012$/ton)

Pollutant:	CO_2	SO_2	NO_x
Program:	RGGI	CAIR	CAIR
2013	$2.95	$0	$35.00
2014	3.94	0	35.00
2015	5.91	0	35.00
2016	6.89	0	35.00
2017	8.86	0	35.00
2018	8.86	0	35.00
2019	9.85	0	35.00
2020	9.85	0	35.00
2021	9.85	0	35.00
2022	9.85	0	35.00
2023	10.83	0	35.00
2024	10.83	0	35.00
2025	10.83	0	35.00
2026	10.83	0	35.00
2027	11.81	0	35.00
2028	11.81	0	35.00
2029	11.81	0	35.00
2030	11.81	0	35.00

[28] The Ventyx model inputs used have changed from those used for the 2011 LTER Reference Case (RC) in light of new environmental regulations that govern SO_2, NO_x, and ozone emissions. The RC assumed that the Clean Air Transport Rule (CATR), which had been approved by the EPA, would be implemented. However, federal courts vacated the EPA replacement for CATR, the Cross-State Air Pollution Rule (CSAPR) in August 2012. As a result, the current rule for SO_2, NO_x, and ozone emissions is the Clean Air Interstate Rule (CAIR), which was the rule in place prior to CATR.

Table 46, Table 47, and Table 48 summarize the marginal emissions reductions in Maryland associated with energy efficiency in the PJM-APS, PJM-SW, and PJM-MidE transmission zones, respectively. The values are based on Ventyx model runs in which small (1 to 3 percent) reductions in load were applied to each PJM region independently. The associated change in annual emissions by plants in Maryland was then divided by the annual load reduction to show emissions savings per MWh of energy saved. An analogous approach was used to create Table 49, Table 50, and Table 51, which summarize the marginal emissions reductions throughout PJM associated with energy efficiency in the PJM-APS, PJM-SW, and PJM-MidE, respectively.

Importantly, even if one were to use these emissions allowance prices and marginal emissions values to estimate the marginal cost of emissions embedded in energy costs, the resulting marginal costs are not intended to encompass environmental externalities or the value of life.

Table 46. Marginal Emissions Reductions in Maryland from a Load Reduction in PJM-APS

Pollutant:	CO_2	SO_2	NO_x
Year	tons/MWh reduced	tons/MWh reduced	tons/MWh reduced
2013	0.045982	0.000035	0.000033
2014	0.066979	0.000060	0.000041
2015	0.080957	0.000058	0.000047
2016	0.058866	0.000057	0.000022
2017	-0.018333	-0.000016	-0.000026
2018	0.229901	0.000183	0.000103
2019	0.077148	0.000049	0.000030
2020	0.072563	0.000072	0.000033
2021	0.053780	0.000041	0.000008
2022	0.086588	0.000073	0.000046
2023	0.077824	0.000059	0.000038
2024	0.038413	0.000027	0.000013
2025	0.038411	-0.000008	0.000011
2026	0.040661	0.000028	0.000021
2027	0.039028	0.000075	0.000022
2028	0.048266	0.000047	0.000021
2029	-0.056400	-0.000065	-0.000041
2030	-0.010030	-0.000022	-0.000009

Table 47. Marginal Emissions Reductions in Maryland from a Load Reduction in PJM-SW

Pollutant:	CO_2	SO_2	NO_x
Year	tons/MWh reduced	tons/MWh reduced	tons/MWh reduced
2013	0.091664	0.000050	0.000050
2014	0.089561	0.000038	0.000038
2015	0.051606	0.000031	0.000031
2016	0.057181	0.000023	0.000023
2017	0.046507	0.000008	0.000008
2018	0.099938	0.000056	0.000056
2019	0.106824	0.000050	0.000050
2020	0.091469	0.000049	0.000049
2021	0.059459	0.000030	0.000030
2022	0.033541	0.000015	0.000015
2023	0.008373	0.000010	0.000010
2024	0.009138	-0.000001	-0.000001
2025	0.043484	0.000029	0.000029
2026	0.024389	0.000021	0.000021
2027	0.000044	0.000005	0.000005
2028	0.033621	0.000029	0.000029
2029	0.037320	0.000029	0.000029
2030	0.036172	0.000020	0.000020

Table 48. Marginal Emissions Reductions in Maryland from a Load Reduction in PJM-MidE

Pollutant:	CO_2	SO_2	NO_x
Year	tons/MWh reduced	tons/MWh reduced	tons/MWh reduced
2013	0.037269	0.000037	0.000027
2014	0.059243	0.000050	0.000029
2015	0.062656	0.000051	0.000037
2016	0.057283	0.000046	0.000030
2017	0.055516	0.000049	0.000021
2018	0.092298	0.000063	0.000048
2019	0.089634	0.000069	0.000036
2020	0.076113	0.000040	0.000041
2021	0.060691	0.000026	0.000029
2022	0.030191	0.000027	0.000014
2023	-0.003791	0.000000	-0.000003
2024	-0.026922	-0.000022	-0.000016
2025	-0.022839	-0.000013	-0.000011
2026	-0.045205	-0.000027	-0.000020
2027	-0.039475	-0.000026	-0.000019
2028	-0.022658	-0.000017	-0.000009
2029	-0.018736	-0.000022	-0.000011
2030	-0.023059	-0.000011	-0.000012

Table 49. Marginal Emissions Reductions in PJM from a Load Reduction in PJM-APS

Pollutant:	CO_2	SO_2	NO_x
Year	tons/MWh reduced	tons/MWh reduced	tons/MWh reduced
2013	0.468175	0.001839	0.000475
2014	0.463933	0.000896	0.000454
2015	0.497435	0.000462	0.000406
2016	0.414724	0.000367	0.000355
2017	0.411229	0.000031	0.000290
2018	0.566108	0.001052	0.000354
2019	0.538502	0.000013	0.000332
2020	0.523521	0.000154	0.000359
2021	0.442903	-0.000045	0.000274
2022	0.331347	0.000204	-0.000101
2023	0.298604	0.000385	-0.000060
2024	0.322789	0.000340	-0.000094
2025	0.347478	0.001024	-0.000048
2026	0.753393	0.000410	-0.000149
2027	0.773744	-0.000136	-0.000069
2028	0.959991	0.000149	0.000052
2029	1.084922	-0.000140	0.000122
2030	0.651483	-0.000681	-0.000012

Table 50. Marginal Emissions Reductions in PJM from a Load Reduction in PJM-SW

Pollutant:	CO_2	SO_2	NO_x
Year	tons/MWh reduced	tons/MWh reduced	tons/MWh reduced
2013	0.513008	0.001543	0.000356
2014	0.500256	0.000739	0.000340
2015	0.435634	0.000491	0.000304
2016	0.442288	0.000489	0.000266
2017	0.380508	0.000287	0.000217
2018	0.477764	0.000420	0.000265
2019	0.483077	0.000268	0.000249
2020	0.480017	0.000308	0.000270
2021	0.389844	0.000025	0.000205
2022	0.227033	0.000159	-0.000076
2023	0.279783	-0.000069	-0.000045
2024	0.279645	0.000067	-0.000070
2025	0.267995	-0.000044	-0.000036
2026	0.605269	-0.000477	-0.000112
2027	0.701522	-0.000310	-0.000052
2028	0.848989	0.000054	0.000039
2029	0.861441	0.000049	0.000091
2030	0.722058	-0.000194	-0.000009

Table 51. Marginal Emissions Reductions in PJM from a Load Reduction in PJM-MidE

Pollutant:	CO_2	SO_2	NO_x
Year	tons/MWh reduced	tons/MWh reduced	tons/MWh reduced
2013	0.451938	0.001246	0.000291
2014	0.434454	0.000544	0.000260
2015	0.429598	0.000432	0.000275
2016	0.406109	0.000329	0.000213
2017	0.488413	0.000277	0.000237
2018	0.483371	0.000235	0.000231
2019	0.483248	0.000266	0.000215
2020	0.464014	0.000205	0.000204
2021	0.417617	0.000141	0.000137
2022	0.391382	0.000060	0.000031
2023	0.342052	0.000033	-0.000002
2024	0.514230	-0.000318	-0.000087
2025	0.493279	-0.000541	-0.000050
2026	0.695826	-0.000641	-0.000098
2027	0.759948	-0.000593	-0.000075
2028	0.822815	-0.000384	-0.000033
2029	0.826855	-0.000220	-0.000010
2030	0.847424	-0.000439	-0.000048

Throughout PJM as a whole, marginal emissions reductions in CO_2 occur every year. In some model years, load reductions are associated with other marginal emissions increases (represented by negative values in the tables above). Projected emissions levels in Maryland and throughout PJM are the result of a complex combination of factors, including: the timing of construction of new, cleaner generating plants; the amount of energy imported into, or exported from, a given transmission zone (versus generated within the transmission zone); and the order in which plants are dispatched to meet load. A reduction in load can reduce generation from newer, cleaner generation facilities and result in increases in emissions at the margin.

Appendix 2. Summary of Results in Nominal Dollars

Table 52. Avoided Cost per Unit Reduced in the Pepco Maryland and SMECO Service Territory, 2015 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	70.77	38.79	60.78	45.82	233.49	1.47	69.59	N/A	N/A	N/A	10.42	17.06
2014	66.02	47.49	57.45	50.08	216.51	1.89	70.84	N/A	N/A	N/A	10.90	17.83
2015	81.87	49.52	59.83	52.24	192.48	2.09	72.33	14.00	1.93	992.73	11.48	18.78
2016	93.26	51.87	64.20	53.25	173.44	2.81	73.85	8.82	1.74	724.04	12.09	19.77
2017	94.91	51.46	64.35	53.18	190.04	3.29	75.40	4.93	1.41	640.45	12.73	20.83
2018	94.88	51.98	65.57	53.56	204.63	4.38	76.98	2.37	1.10	555.51	13.41	21.94
2019	95.65	52.47	66.33	54.06	220.33	5.17	78.60	2.02	0.95	482.39	14.11	23.10
2020	96.93	52.88	67.17	56.48	237.23	4.80	80.25	0.04	0.77	419.11	14.87	24.32
2021	98.46	54.61	69.51	56.49	255.45	4.53	81.93	0.26	0.39	363.67	15.66	25.62
2022	101.58	57.05	72.61	60.58	275.05	4.34	83.66	(0.45)	0.17	315.42	16.49	26.98
2023	104.97	59.71	74.72	61.96	296.17	3.52	85.41	0.36	0.02	273.78	17.37	28.42
2024	105.96	61.81	77.08	65.33	318.90	3.16	87.21	0.17	0.15	237.35	18.30	29.93
2025	109.12	67.51	78.43	66.83	343.38	2.62	89.04	0.26	0.19	206.02	19.27	31.52
2026	112.28	70.17	81.27	68.13	369.74	2.26	90.91	0.00	0.20	178.67	20.29	33.19
2027	114.41	67.78	83.41	70.09	398.12	1.72	92.82	0.01	0.12	154.92	21.37	34.96
2028	118.20	70.52	85.66	72.43	428.67	1.30	94.77	(0.06)	0.07	134.25	22.50	36.82
2029	121.66	71.92	88.05	74.39	461.58	0.84	96.76	0.06	0.06	116.41	23.70	38.78
2030	124.14	74.16	91.23	76.70	497.01	0.74	98.79	0.00	0.06	100.96	24.95	40.85

Table 53. Avoided Cost per Unit Reduced in the Pepco Maryland and SMECO Service Territory, 2016 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	70.77	38.79	60.78	45.82	233.49	1.47	69.59	N/A	N/A	N/A	10.42	17.06
2014	66.02	47.49	57.45	50.08	216.51	1.89	70.84	N/A	N/A	N/A	10.90	17.83
2015	81.87	49.52	59.83	52.24	192.48	2.09	72.33	N/A	N/A	N/A	11.48	18.78
2016	93.26	51.87	64.20	53.25	173.44	2.81	73.85	11.02	2.17	905.06	12.09	19.77
2017	94.91	51.46	64.35	53.18	190.04	3.29	75.40	6.16	1.76	800.55	12.73	20.83
2018	94.88	51.98	65.57	53.56	204.63	4.38	76.98	2.97	1.38	694.39	13.41	21.94
2019	95.65	52.47	66.33	54.06	220.33	5.17	78.60	2.52	1.19	602.99	14.11	23.10
2020	96.93	52.88	67.17	56.48	237.23	4.80	80.25	0.05	0.97	523.88	14.87	24.32
2021	98.46	54.61	69.51	56.49	255.45	4.53	81.93	0.32	0.49	454.59	15.66	25.62
2022	101.58	57.05	72.61	60.58	275.05	4.34	83.66	(0.56)	0.21	394.27	16.49	26.98
2023	104.97	59.71	74.72	61.96	296.17	3.52	85.41	0.45	0.02	342.22	17.37	28.42
2024	105.96	61.81	77.08	65.33	318.90	3.16	87.21	0.20	0.19	296.70	18.30	29.93
2025	109.12	67.51	78.43	66.83	343.38	2.62	89.04	0.34	0.23	257.52	19.27	31.52
2026	112.28	70.17	81.27	68.13	369.74	2.26	90.91	(0.01)	0.24	223.35	20.29	33.19
2027	114.41	67.78	83.41	70.09	398.12	1.72	92.82	0.03	0.16	193.65	21.37	34.96
2028	118.20	70.52	85.66	72.43	428.67	1.30	94.77	(0.07)	0.08	167.81	22.50	36.82
2029	121.66	71.92	88.05	74.39	461.58	0.84	96.76	0.07	0.07	145.53	23.70	38.78
2030	124.14	74.16	91.23	76.70	497.01	0.74	98.79	0.00	0.07	126.20	24.95	40.85

Table 54. Avoided Cost per Unit Reduced in the Pepco Maryland and SMECO Service Territory, 2017 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	70.77	38.79	60.78	45.82	233.49	1.47	69.59	N/A	N/A	N/A	10.42	17.06
2014	66.02	47.49	57.45	50.08	216.51	1.89	70.84	N/A	N/A	N/A	10.90	17.83
2015	81.87	49.52	59.83	52.24	192.48	2.09	72.33	N/A	N/A	N/A	11.48	18.78
2016	93.26	51.87	64.20	53.25	173.44	2.81	73.85	N/A	N/A	N/A	12.09	19.77
2017	94.91	51.46	64.35	53.18	190.04	3.29	75.40	9.57	1.88	1000.69	12.73	20.83
2018	94.88	51.98	65.57	53.56	204.63	4.38	76.98	5.35	1.53	867.99	13.41	21.94
2019	95.65	52.47	66.33	54.06	220.33	5.17	78.60	2.57	1.19	753.74	14.11	23.10
2020	96.93	52.88	67.17	56.48	237.23	4.80	80.25	2.19	1.03	654.86	14.87	24.32
2021	98.46	54.61	69.51	56.49	255.45	4.53	81.93	0.05	0.84	568.23	15.66	25.62
2022	101.58	57.05	72.61	60.58	275.05	4.34	83.66	0.28	0.43	492.84	16.49	26.98
2023	104.97	59.71	74.72	61.96	296.17	3.52	85.41	(0.49)	0.19	427.78	17.37	28.42
2024	105.96	61.81	77.08	65.33	318.90	3.16	87.21	0.39	0.03	370.86	18.30	29.93
2025	109.12	67.51	78.43	66.83	343.38	2.62	89.04	0.18	0.16	321.89	19.27	31.52
2026	112.28	70.17	81.27	68.13	369.74	2.26	90.91	0.29	0.21	279.19	20.29	33.19
2027	114.41	67.78	83.41	70.09	398.12	1.72	92.82	(0.01)	0.22	242.05	21.37	34.96
2028	118.20	70.52	85.66	72.43	428.67	1.30	94.77	0.03	0.14	209.78	22.50	36.82
2029	121.66	71.92	88.05	74.39	461.58	0.84	96.76	(0.06)	0.07	181.90	23.70	38.78
2030	124.14	74.16	91.23	76.70	497.01	0.74	98.79	0.07	0.06	157.74	24.95	40.85

Table 55. Avoided Cost per Unit Reduced in the BGE Service Territory, 2015 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	69.30	37.99	59.52	44.87	233.49	1.47	94.99	N/A	N/A	N/A	11.53	8.69
2014	64.65	46.50	56.27	49.05	216.51	1.89	96.70	N/A	N/A	N/A	12.05	9.08
2015	80.16	48.49	58.59	51.15	192.48	2.09	98.73	14.00	1.93	992.73	12.69	9.57
2016	91.32	50.79	62.86	52.15	173.44	2.81	100.80	8.82	1.74	724.04	13.37	10.08
2017	92.93	50.40	63.02	52.08	190.04	3.29	102.92	4.93	1.41	640.45	14.08	10.61
2018	92.91	50.90	64.21	52.44	204.63	4.38	105.08	2.37	1.10	555.51	14.83	11.18
2019	93.66	51.38	64.95	52.94	220.33	5.17	107.29	2.02	0.95	482.39	15.62	11.77
2020	94.91	51.77	65.76	55.31	237.23	4.80	109.54	0.04	0.77	419.11	16.45	12.40
2021	96.42	53.47	68.07	55.31	255.45	4.53	111.84	0.26	0.39	363.67	17.32	13.05
2022	99.47	55.87	71.10	59.32	275.05	4.34	114.19	(0.45)	0.17	315.42	18.24	13.75
2023	102.79	58.46	73.18	60.67	296.17	3.52	116.59	0.36	0.02	273.78	19.21	14.48
2024	103.75	60.53	75.48	63.97	318.90	3.16	119.04	0.17	0.15	237.35	20.23	15.25
2025	106.84	66.10	76.79	65.44	343.38	2.62	121.54	0.26	0.19	206.02	21.31	16.06
2026	109.95	68.71	79.57	66.71	369.74	2.26	124.09	0.00	0.20	178.67	22.44	16.91
2027	112.03	66.37	81.67	68.62	398.12	1.72	126.69	0.01	0.12	154.92	23.63	17.81
2028	115.75	69.05	83.89	70.92	428.67	1.30	129.35	(0.06)	0.07	134.25	24.89	18.76
2029	119.13	70.42	86.23	72.84	461.58	0.84	132.07	0.06	0.06	116.41	26.21	19.76
2030	121.56	72.62	89.32	75.10	497.01	0.74	134.84	0.00	0.06	100.96	27.61	20.81

Table 56. Avoided Cost per Unit Reduced in the BGE Service Territory, 2016 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	69.30	37.99	59.52	44.87	233.49	1.47	94.99	N/A	N/A	N/A	11.53	8.69
2014	64.65	46.50	56.27	49.05	216.51	1.89	96.70	N/A	N/A	N/A	12.05	9.08
2015	80.16	48.49	58.59	51.15	192.48	2.09	98.73	N/A	N/A	N/A	12.69	9.57
2016	91.32	50.79	62.86	52.15	173.44	2.81	100.80	11.02	2.17	905.06	13.37	10.08
2017	92.93	50.40	63.02	52.08	190.04	3.29	102.92	6.16	1.76	800.55	14.08	10.61
2018	92.91	50.90	64.21	52.44	204.63	4.38	105.08	2.97	1.38	694.39	14.83	11.18
2019	93.66	51.38	64.95	52.94	220.33	5.17	107.29	2.52	1.19	602.99	15.62	11.77
2020	94.91	51.77	65.76	55.31	237.23	4.80	109.54	0.05	0.97	523.88	16.45	12.40
2021	96.42	53.47	68.07	55.31	255.45	4.53	111.84	0.32	0.49	454.59	17.32	13.05
2022	99.47	55.87	71.10	59.32	275.05	4.34	114.19	(0.56)	0.21	394.27	18.24	13.75
2023	102.79	58.46	73.18	60.67	296.17	3.52	116.59	0.45	0.02	342.22	19.21	14.48
2024	103.75	60.53	75.48	63.97	318.90	3.16	119.04	0.20	0.19	296.70	20.23	15.25
2025	106.84	66.10	76.79	65.44	343.38	2.62	121.54	0.34	0.23	257.52	21.31	16.06
2026	109.95	68.71	79.57	66.71	369.74	2.26	124.09	(0.01)	0.24	223.35	22.44	16.91
2027	112.03	66.37	81.67	68.62	398.12	1.72	126.69	0.03	0.16	193.65	23.63	17.81
2028	115.75	69.05	83.89	70.92	428.67	1.30	129.35	(0.07)	0.08	167.81	24.89	18.76
2029	119.13	70.42	86.23	72.84	461.58	0.84	132.07	0.07	0.07	145.53	26.21	19.76
2030	121.56	72.62	89.32	75.10	497.01	0.74	134.84	0.00	0.07	126.20	27.61	20.81

Table 57. Avoided Cost per Unit Reduced in the BGE Service Territory, 2017 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	69.30	37.99	59.52	44.87	233.49	1.47	94.99	N/A	N/A	N/A	11.53	8.69
2014	64.65	46.50	56.27	49.05	216.51	1.89	96.70	N/A	N/A	N/A	12.05	9.08
2015	80.16	48.49	58.59	51.15	192.48	2.09	98.73	N/A	N/A	N/A	12.69	9.57
2016	91.32	50.79	62.86	52.15	173.44	2.81	100.80	N/A	N/A	N/A	13.37	10.08
2017	92.93	50.40	63.02	52.08	190.04	3.29	102.92	9.57	1.88	1000.69	14.08	10.61
2018	92.91	50.90	64.21	52.44	204.63	4.38	105.08	5.35	1.53	867.99	14.83	11.18
2019	93.66	51.38	64.95	52.94	220.33	5.17	107.29	2.57	1.19	753.74	15.62	11.77
2020	94.91	51.77	65.76	55.31	237.23	4.80	109.54	2.19	1.03	654.86	16.45	12.40
2021	96.42	53.47	68.07	55.31	255.45	4.53	111.84	0.05	0.84	568.23	17.32	13.05
2022	99.47	55.87	71.10	59.32	275.05	4.34	114.19	0.28	0.43	492.84	18.24	13.75
2023	102.79	58.46	73.18	60.67	296.17	3.52	116.59	(0.49)	0.19	427.78	19.21	14.48
2024	103.75	60.53	75.48	63.97	318.90	3.16	119.04	0.39	0.03	370.86	20.23	15.25
2025	106.84	66.10	76.79	65.44	343.38	2.62	121.54	0.18	0.16	321.89	21.31	16.06
2026	109.95	68.71	79.57	66.71	369.74	2.26	124.09	0.29	0.21	279.19	22.44	16.91
2027	112.03	66.37	81.67	68.62	398.12	1.72	126.69	(0.01)	0.22	242.05	23.63	17.81
2028	115.75	69.05	83.89	70.92	428.67	1.30	129.35	0.03	0.14	209.78	24.89	18.76
2029	119.13	70.42	86.23	72.84	461.58	0.84	132.07	(0.06)	0.07	181.90	26.21	19.76
2030	121.56	72.62	89.32	75.10	497.01	0.74	134.84	0.07	0.06	157.74	27.61	20.81

Table 58. Avoided Cost per Unit Reduced in the DPL Maryland Service Territory, 2015 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	72.23	40.28	56.53	43.74	250.48	1.47	69.59	N/A	N/A	N/A	4.92	2.30
2014	72.15	46.80	58.18	49.86	226.28	1.89	70.84	N/A	N/A	N/A	5.14	2.41
2015	88.17	49.44	60.86	50.53	192.48	2.09	72.33	6.02	1.47	66.99	5.42	2.53
2016	98.58	51.53	64.84	52.95	173.44	2.81	73.85	3.91	1.47	48.98	5.70	2.66
2017	100.46	51.23	65.23	52.97	195.26	3.29	75.40	4.56	1.21	44.48	6.01	2.81
2018	98.24	51.72	66.08	53.26	210.26	4.38	76.98	2.51	0.97	38.50	6.33	2.96
2019	97.76	51.97	66.71	53.56	226.40	5.17	78.60	2.10	0.70	33.37	6.67	3.12
2020	98.18	52.51	67.77	54.26	243.77	4.80	80.25	0.76	0.59	28.93	7.02	3.28
2021	99.86	54.20	70.26	56.19	262.48	4.53	81.93	(0.16)	0.31	25.16	7.39	3.46
2022	102.16	56.77	72.92	58.70	282.63	4.34	83.66	(0.34)	0.17	21.87	7.79	3.64
2023	105.57	59.67	75.46	61.95	304.32	3.52	85.41	(0.31)	(0.01)	18.99	8.21	3.83
2024	106.10	61.73	78.15	63.85	327.69	3.16	87.21	(0.09)	(0.04)	16.46	8.63	4.04
2025	108.43	63.07	79.30	65.69	352.83	2.62	89.04	(0.31)	(0.06)	14.30	9.10	4.25
2026	111.18	65.99	82.32	68.49	379.92	2.26	90.91	(0.50)	(0.07)	12.44	9.58	4.47
2027	113.97	68.09	84.42	70.37	409.08	1.72	92.82	(0.35)	(0.05)	10.79	10.08	4.72
2028	116.77	70.92	87.01	73.22	440.47	1.30	94.77	(0.26)	(0.04)	9.37	10.63	4.97
2029	122.15	72.81	89.87	75.87	474.29	0.84	96.76	(0.11)	(0.03)	8.14	11.19	5.23
2030	121.59	74.75	92.15	77.94	510.69	0.74	98.79	(0.13)	(0.01)	7.07	11.78	5.51

Table 59. Avoided Cost per Unit Reduced in the DPL Maryland Service Territory, 2016 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	72.23	40.28	56.53	43.74	250.48	1.47	69.59	N/A	N/A	N/A	4.92	2.30
2014	72.15	46.80	58.18	49.86	226.28	1.89	70.84	N/A	N/A	N/A	5.14	2.41
2015	88.17	49.44	60.86	50.53	192.48	2.09	72.33	N/A	N/A	N/A	5.42	2.53
2016	98.58	51.53	64.84	52.95	173.44	2.81	73.85	4.89	1.83	61.23	5.70	2.66
2017	100.46	51.23	65.23	52.97	195.26	3.29	75.40	5.70	1.52	55.60	6.01	2.81
2018	98.24	51.72	66.08	53.26	210.26	4.38	76.98	3.12	1.20	48.12	6.33	2.96
2019	97.76	51.97	66.71	53.56	226.40	5.17	78.60	2.62	0.87	41.71	6.67	3.12
2020	98.18	52.51	67.77	54.26	243.77	4.80	80.25	0.95	0.74	36.17	7.02	3.28
2021	99.86	54.20	70.26	56.19	262.48	4.53	81.93	(0.19)	0.38	31.45	7.39	3.46
2022	102.16	56.77	72.92	58.70	282.63	4.34	83.66	(0.43)	0.21	27.33	7.79	3.64
2023	105.57	59.67	75.46	61.95	304.32	3.52	85.41	(0.39)	(0.02)	23.73	8.21	3.83
2024	106.10	61.73	78.15	63.85	327.69	3.16	87.21	(0.11)	(0.05)	20.59	8.63	4.04
2025	108.43	63.07	79.30	65.69	352.83	2.62	89.04	(0.40)	(0.09)	17.87	9.10	4.25
2026	111.18	65.99	82.32	68.49	379.92	2.26	90.91	(0.62)	(0.08)	15.54	9.58	4.47
2027	113.97	68.09	84.42	70.37	409.08	1.72	92.82	(0.45)	(0.07)	13.48	10.08	4.72
2028	116.77	70.92	87.01	73.22	440.47	1.30	94.77	(0.33)	(0.06)	11.72	10.63	4.97
2029	122.15	72.81	89.87	75.87	474.29	0.84	96.76	(0.16)	(0.03)	10.17	11.19	5.23
2030	121.59	74.75	92.15	77.94	510.69	0.74	98.79	(0.16)	(0.03)	8.84	11.78	5.51

Table 60. Avoided Cost per Unit Reduced in the DPL Maryland Service Territory, 2017 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	72.23	40.28	56.53	43.74	250.48	1.47	69.59	N/A	N/A	N/A	4.92	2.30
2014	72.15	46.80	58.18	49.86	226.28	1.89	70.84	N/A	N/A	N/A	5.14	2.41
2015	88.17	49.44	60.86	50.53	192.48	2.09	72.33	N/A	N/A	N/A	5.42	2.53
2016	98.58	51.53	64.84	52.95	173.44	2.81	73.85	N/A	N/A	N/A	5.70	2.66
2017	100.46	51.23	65.23	52.97	195.26	3.29	75.40	4.25	1.59	69.51	6.01	2.81
2018	98.24	51.72	66.08	53.26	210.26	4.38	76.98	4.95	1.32	60.15	6.33	2.96
2019	97.76	51.97	66.71	53.56	226.40	5.17	78.60	2.72	1.04	52.13	6.67	3.12
2020	98.18	52.51	67.77	54.26	243.77	4.80	80.25	2.27	0.76	45.20	7.02	3.28
2021	99.86	54.20	70.26	56.19	262.48	4.53	81.93	0.83	0.63	39.31	7.39	3.46
2022	102.16	56.77	72.92	58.70	282.63	4.34	83.66	(0.17)	0.34	34.17	7.79	3.64
2023	105.57	59.67	75.46	61.95	304.32	3.52	85.41	(0.37)	0.19	29.67	8.21	3.83
2024	106.10	61.73	78.15	63.85	327.69	3.16	87.21	(0.34)	(0.01)	25.73	8.63	4.04
2025	108.43	63.07	79.30	65.69	352.83	2.62	89.04	(0.09)	(0.04)	22.35	9.10	4.25
2026	111.18	65.99	82.32	68.49	379.92	2.26	90.91	(0.35)	(0.08)	19.42	9.58	4.47
2027	113.97	68.09	84.42	70.37	409.08	1.72	92.82	(0.54)	(0.07)	16.86	10.08	4.72
2028	116.77	70.92	87.01	73.22	440.47	1.30	94.77	(0.39)	(0.06)	14.64	10.63	4.97
2029	122.15	72.81	89.87	75.87	474.29	0.84	96.76	(0.28)	(0.06)	12.71	11.19	5.23
2030	121.59	74.75	92.15	77.94	510.69	0.74	98.79	(0.13)	(0.03)	11.05	11.78	5.51

Table 61. Avoided Cost per Unit Reduced in the Potomac Edison Maryland Service Territory, 2015 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	61.39	36.34	52.35	41.29	28.68	1.47	69.59	N/A	N/A	N/A	5.83	5.65
2014	61.00	42.06	53.16	43.92	105.91	1.89	70.84	N/A	N/A	N/A	6.09	5.91
2015	72.47	47.95	57.72	48.34	164.17	2.09	72.33	(1.82)	1.99	26.64	6.42	6.22
2016	81.26	50.22	61.92	51.48	113.69	2.81	73.85	1.67	1.93	15.02	6.76	6.56
2017	83.37	49.80	62.26	51.46	108.64	3.29	75.40	6.08	2.37	11.61	7.12	6.90
2018	83.95	50.08	63.51	51.84	116.98	4.38	76.98	5.78	1.92	10.08	7.50	7.27
2019	86.41	50.37	64.26	52.26	125.95	5.17	78.60	3.49	1.73	8.78	7.90	7.65
2020	88.25	50.78	65.04	52.62	135.63	4.80	80.25	0.69	0.91	7.65	8.32	8.06
2021	91.42	52.26	67.40	54.58	146.04	4.53	81.93	1.18	0.71	6.65	8.76	8.49
2022	95.56	54.67	70.36	56.35	157.25	4.34	83.66	1.66	0.44	5.79	9.22	8.94
2023	97.59	56.54	72.43	59.48	169.32	3.52	85.41	1.31	0.31	5.04	9.71	9.41
2024	99.26	58.47	74.67	60.81	182.31	3.16	87.21	1.03	0.27	4.37	10.24	9.92
2025	101.62	58.65	76.01	62.66	196.30	2.62	89.04	0.74	0.22	3.80	10.78	10.45
2026	104.12	61.17	78.53	65.15	211.38	2.26	90.91	0.27	0.21	3.30	11.35	11.00
2027	106.30	64.25	80.53	67.19	227.61	1.72	92.82	0.12	0.16	2.87	11.95	11.59
2028	109.81	66.56	82.74	69.41	245.07	1.30	94.77	(0.39)	0.04	2.50	12.59	12.20
2029	111.54	68.36	85.00	71.31	263.88	0.84	96.76	(0.35)	(0.01)	2.18	13.26	12.85
2030	115.93	70.48	87.91	73.25	284.13	0.74	98.79	(0.49)	(0.04)	1.89	13.96	13.53

Table 62. Avoided Cost per Unit Reduced in the Potomac Edison Maryland Service Territory, 2016 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	61.39	36.34	52.35	41.29	28.68	1.47	69.59	N/A	N/A	N/A	5.83	5.65
2014	61.00	42.06	53.16	43.92	105.91	1.89	70.84	N/A	N/A	N/A	6.09	5.91
2015	72.47	47.95	57.72	48.34	164.17	2.09	72.33	N/A	N/A	N/A	6.42	6.22
2016	81.26	50.22	61.92	51.48	113.69	2.81	73.85	2.09	2.42	18.77	6.76	6.56
2017	83.37	49.80	62.26	51.46	108.64	3.29	75.40	7.60	2.96	14.52	7.12	6.90
2018	83.95	50.08	63.51	51.84	116.98	4.38	76.98	7.22	2.41	12.61	7.50	7.27
2019	86.41	50.37	64.26	52.26	125.95	5.17	78.60	4.36	2.17	10.97	7.90	7.65
2020	88.25	50.78	65.04	52.62	135.63	4.80	80.25	0.87	1.14	9.56	8.32	8.06
2021	91.42	52.26	67.40	54.58	146.04	4.53	81.93	1.47	0.87	8.31	8.76	8.49
2022	95.56	54.67	70.36	56.35	157.25	4.34	83.66	2.08	0.55	7.23	9.22	8.94
2023	97.59	56.54	72.43	59.48	169.32	3.52	85.41	1.65	0.40	6.30	9.71	9.41
2024	99.26	58.47	74.67	60.81	182.31	3.16	87.21	1.29	0.33	5.46	10.24	9.92
2025	101.62	58.65	76.01	62.66	196.30	2.62	89.04	0.94	0.27	4.76	10.78	10.45
2026	104.12	61.17	78.53	65.15	211.38	2.26	90.91	0.33	0.27	4.14	11.35	11.00
2027	106.30	64.25	80.53	67.19	227.61	1.72	92.82	0.15	0.19	3.59	11.95	11.59
2028	109.81	66.56	82.74	69.41	245.07	1.30	94.77	(0.48)	0.06	3.13	12.59	12.20
2029	111.54	68.36	85.00	71.31	263.88	0.84	96.76	(0.44)	(0.03)	2.73	13.26	12.85
2030	115.93	70.48	87.91	73.25	284.13	0.74	98.79	(0.61)	(0.06)	2.37	13.96	13.53

Table 63. Avoided Cost per Unit Reduced in the Potomac Edison Maryland Service Territory, 2017 DRIPE (Nominal $)

	Summer Electric Energy ($/MWh)		Non-Summer Electric Energy ($/MWh)		Electric Generating Capacity ($/MW-day)	Renewable Energy ($/MWh)	Transmission and Distribution ($/MW-day)	DRIPE Energy ($/MWh)		DRIPE Capacity ($/MW-day)	Water and Wastewater ($/kgal)	
	On-Peak	Off-Peak	On-Peak	Off-Peak				On-Peak	Off-Peak		Residential	C&I
2013	61.39	36.34	52.35	41.29	28.68	1.47	69.59	N/A	N/A	N/A	5.83	5.65
2014	61.00	42.06	53.16	43.92	105.91	1.89	70.84	N/A	N/A	N/A	6.09	5.91
2015	72.47	47.95	57.72	48.34	164.17	2.09	72.33	N/A	N/A	N/A	6.42	6.22
2016	81.26	50.22	61.92	51.48	113.69	2.81	73.85	N/A	N/A	N/A	6.76	6.56
2017	83.37	49.80	62.26	51.46	108.64	3.29	75.40	1.82	2.09	18.15	7.12	6.90
2018	83.95	50.08	63.51	51.84	116.98	4.38	76.98	6.60	2.57	15.76	7.50	7.27
2019	86.41	50.37	64.26	52.26	125.95	5.17	78.60	6.27	2.09	13.71	7.90	7.65
2020	88.25	50.78	65.04	52.62	135.63	4.80	80.25	3.78	1.87	11.95	8.32	8.06
2021	91.42	52.26	67.40	54.58	146.04	4.53	81.93	0.75	0.99	10.40	8.76	8.49
2022	95.56	54.67	70.36	56.35	157.25	4.34	83.66	1.28	0.76	9.04	9.22	8.94
2023	97.59	56.54	72.43	59.48	169.32	3.52	85.41	1.81	0.47	7.87	9.71	9.41
2024	99.26	58.47	74.67	60.81	182.31	3.16	87.21	1.43	0.34	6.84	10.24	9.92
2025	101.62	58.65	76.01	62.66	196.30	2.62	89.04	1.12	0.29	5.94	10.78	10.45
2026	104.12	61.17	78.53	65.15	211.38	2.26	90.91	0.81	0.24	5.18	11.35	11.00
2027	106.30	64.25	80.53	67.19	227.61	1.72	92.82	0.30	0.23	4.50	11.95	11.59
2028	109.81	66.56	82.74	69.41	245.07	1.30	94.77	0.12	0.17	3.92	12.59	12.20
2029	111.54	68.36	85.00	71.31	263.88	0.84	96.76	(0.42)	0.06	3.40	13.26	12.85
2030	115.93	70.48	87.91	73.25	284.13	0.74	98.79	(0.37)	(0.01)	2.96	13.96	13.53

Table 64. Avoided Cost of Other Fuels for Residential Customers (Nominal $/MMBtu)

Year	Natural Gas	Propane	Fuel Oil
2013	$11.96	$26.88	$26.60
2014	12.48	26.80	26.98
2015	12.61	26.57	27.53
2016	12.85	27.25	28.52
2017	13.48	28.73	29.61
2018	14.11	29.92	30.63
2019	14.76	31.12	31.75
2020	15.31	32.32	32.87
2021	15.81	33.40	34.06
2022	16.39	34.55	35.28
2023	16.93	35.68	36.56
2024	17.50	36.79	37.90
2025	18.02	37.92	39.32
2026	18.68	39.08	40.73
2027	19.16	40.21	42.19
2028	19.68	41.36	43.71
2029	20.21	42.50	45.27
2030	20.75	43.69	46.81

Table 65. Avoided Cost of Other Fuels for Commercial Customers (Nominal $/MMBtu)

Year	Natural Gas	Propane	Fuel Oil
2013	$10.14	$21.01	$25.52
2014	10.52	20.76	23.82
2015	10.61	20.33	24.38
2016	10.73	20.88	25.31
2017	11.25	22.33	26.39
2018	11.76	23.46	27.39
2019	12.31	24.59	28.50
2020	12.75	25.73	29.51
2021	13.12	26.73	30.71
2022	13.58	27.82	31.99
2023	13.98	28.87	33.17
2024	14.43	29.90	34.41
2025	14.81	30.94	35.73
2026	15.36	32.02	37.03
2027	15.69	33.05	38.36
2028	16.05	34.11	39.76
2029	16.44	35.16	41.17
2030	16.82	36.25	42.57

Table 66. Avoided Cost of Other Fuels for Industrial Customers (Nominal $/MMBtu)

Year	Natural Gas	Propane	Fuel Oil
2013	$6.97	$19.70	$26.42
2014	7.41	19.42	24.23
2015	7.63	18.97	24.86
2016	7.65	19.50	25.81
2017	8.05	20.90	26.92
2018	8.46	21.99	27.98
2019	8.91	23.09	29.14
2020	9.26	24.19	30.13
2021	9.51	25.16	31.41
2022	9.87	26.20	32.81
2023	10.17	27.22	33.97
2024	10.54	28.22	35.20
2025	10.82	29.22	36.53
2026	11.29	30.26	37.81
2027	11.51	31.26	39.13
2028	11.77	32.28	40.51
2029	12.06	33.29	41.90
2030	12.33	34.34	43.27

Appendix 3. Demand Reduction Induced Price Effects (DRIPE) Methodological Equations

Energy DRIPE

(1) For each transmission zone:

$$D_{ht}^{i} = BCPE_{ht}^{i} - RLPE_{ht}^{i}$$

Where: BCPE is the price of energy calculated with the Ventyx Model from the hourly loads used in the Avoided Cost Study Base Case.

RLPE is the price of energy calculated with the Ventyx Model from hourly loads reduced for the zone relative to the Avoided Cost Base Case scenario. For the PJM-SW zone (which includes BGE, Pepco, and SMECO) load in each hour of each year was reduced by 200 MW; for the PJM-APS zone (which includes PE), load was reduced by 150 MW; and load was reduced by 300 MW in each hour for the PJM-MidE zone (which encompasses DPL).

h denotes hour of the year
t denotes the year
i denotes the zone

(2a) For all on-peak hours in each year:

$$\mathrm{ONPEAKD}_{t}^{i} = \left(\sum_{h=1}^{N} \mathrm{D}_{ht}^{i}\right)/\mathrm{N}$$

Where: ONPEAKD = the annual average on-peak energy price differential.

N is the number of on-peak hours in the year.

(2b) For all off-peak hours in each year:

$$OFFPEAKD_t^i = \left(\sum_{h=1}^{M} D_{ht}^i\right)/M$$

Where: OFFPEAKD = the annual average off-peak energy price differential.

M is the number of off-peak hours in the year.

(3a) For each transmission zone:

$$ONPEAKMDEDRIPE_t^i = \sum_{i=1}^{3}\left[\frac{\left(ONPEAKD_t^i(1-R)^t\ x\ ONPEAKMWH_t^i\ x\ MDSHARE^i\right)}{\left(N\ x\ RLMW_t^i\right)}\right]$$

Where: ONPEAKMDEDRIPE is the total on-peak Maryland per MWH reduction in revenues from the three Ventyx transmission zones covering parts of Maryland.

ONPEAKMWH is total on-peak MWH sales in the zone.

MDSHARE is the share of MWH sales in the zone going to Maryland customers.

R is the assumed decay factor set to 0.2.

$RLMW_t$ is the number of MW of reduced load in relevant zone for the Ventyx load reduction scenario.

(3b) For each transmission zone:

$$OFFPEAKMDEDRIPE_t^i = \sum_{i=1}^{3}\left[\frac{\left(OFFPEAKD_t^i(1-R)^t\ x\ OFFPEAKMWH_t^i\ x\ MDSHARE^i\right)}{\left(M\ x\ RLMW_t^i\right)}\right]$$

Where: OFFPEAKMDEDRIPE is the total off-peak Maryland per MWH reduction in revenues for the three Ventyx transmission zones covering parts of Maryland.

OFFPEAKMWH is total off-peak MWH sales in the zone.

(4a) For Maryland:

$$TOTALONPEAKMDEDRIPE_{\mathrm{t}} = \sum_{\mathrm{i}=1}^{3} \left(ONPEAKMDEDRIPE_{\mathrm{t}}^{\mathrm{i}}\right)$$

Where: *TOTALONPEAKMDEDRIPE* is the average on-peak per MWH DRIPE in Maryland during time t.

(4a) For Maryland:

$$TOTALOFFPEAKMDEDR\mathrm{IPE}_{\mathrm{t}} = \sum_{\mathrm{i}=1}^{3} \left(OFFPE\mathrm{AKMDEDRIPE}_{\mathrm{t}}^{\mathrm{i}}\right)$$

Where: *TOTALOFFPEAKMDEDRIPE* is the average off-peak per MWH DRIPE in Maryland during time t.

Capacity DRIPE

(5) For each transmission zone:

$$\mathrm{CAPACITYDIFF}_t^i = \frac{\left(\mathrm{CAPRICE}_t^i \text{ x } \mathrm{PJMRR} \text{ x } \mathcal{E}_i \text{ x } (1 - \mathrm{R})^t\right)}{(\mathrm{CAPACITY}_i \text{ x } 0.01)}$$

Where: CAPACITYDIFF is the estimated change in price for a given change in quantity.

CAPRICE is the Avoided Cost Study Base Case capacity price in zone i during year t.

PJMRR is the PJM UCAP reserve requirement of 1.09.

Ɛ is the estimated price elasticity of supply in transmission zone i.

CAPACITY is the number of MW that cleared PJM's capacity market in zone i during the most recent capacity auction.

(6) For each transmission zone:

$$CAPACITYDRIPE_t^i = \left(CAPACITYDIFF_t^i \ x \ DEMAND_i\right)$$

Where: CAPACITYDRIPE is the estimated annual capacity-related DRIPE in zone i during year t, in terms of dollars per MW-day.

DEMAND is the number of MW in the Maryland portion of each transmission zone.