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MEMORANDUM

TO: Philip Cherry
Director
Division of Energy & Climate

FROM: Thomas Noyes
Principal Planner for Utility Policy
Division of Energy & Climate

DATE: October 28, 2016

SUBJECT: **Provisional Renewable Energy Portfolio Standards Cost Cap Analysis**

Executive Summary

The Division of Energy & Climate is required to report on the cost of RPS compliance under Section 4.0 of 104 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions (Regulation) promulgated under 26 *Del. C.* § 354(i) & (j). The Director of the Division may, in consultation with the PSC, decide to freeze the RPS as provided in Section 5.0 of the Regulation. In this memorandum, I present the calculations required in Section 4.0 and assess the benefits of the RPS as provided in Section 5.0 of the Regulation.

For Compliance Year 2015/16 (June 1, 2015 to May 31, 2016) our preliminary calculations of benefits effectively equaled the cost of compliance for the RPS and exceeded the cost of compliance of the solar PV carve-out. These calculations should be considered provisional for reasons described below.

The externality benefits and the economic benefits of solar PV used to satisfy DPL's solar carve-out totaled 2.24 percent, far greater than the 1.28 percent cost of solar PV compliance. The externality benefits and the economic benefits of renewable energy used to satisfy DPL's RPS requirement totaled 4.71 percent, which is close to the 4.69 percent cost of RPS compliance. These are preliminary figures and may change slightly as we complete the economic analysis of the solar industry jobs survey.

Pending final completion of this analysis, we reasonably expect to report that you would be justified in deciding not to freeze the RPS. The costs and benefits for the solar PV carve-out and the RPS are presented in detail below.

Solar PV Costs and Benefits

I have calculated the solar PV cost of compliance as follows:

Section 4.3 Solar Renewable Energy Cost of Compliance

The Solar Energy Cost of Compliance in Compliance Year 2015/16 was $8,738,344, or 1.28 percent of the total retail cost of electricity of $682,403,734. (Appendix 3) The statute gives the Director discretion, in consultation with the PSC, to decide whether to freeze the RPS. Section 5.0 of the Regulation directs how the Director will make a determination whether to declare a freeze. I have analyzed the following benefits to be considered in a determination as follows:

Section 5.4.1 Overall energy market conditions

Overall market energy conditions have not changed sufficiently enough to significantly affect this analysis.

Section 5.4.2 Avoided cost benefits from solar PV carve-out

Avoided cost benefits are those market benefits known as price suppression effects attributable to reduced demand because of distributed renewable energy generation in PJM, which leads to lower capacity and energy prices particularly at times of peak demand. The Division has engaged the National Renewable Energy Laboratory (NREL), Delmarva Power and PJM Interconnection LLC to develop methods to calculate the price suppression effects of distributed PV in Delaware. NREL calculated the distributed PV generation for each of 8,760 hours of compliance year 2013/14 and the degree to which this output suppressed market prices based on PJM's monthly locational marginal price curve. NREL calculated the price suppression effect of distributed PV in Delaware to be between 0.05 percent and 0.5 percent of the total retail cost of electricity during compliance year 2013/14. (Appendix 5)

The Division is currently working with NREL and PJM to refine the methods and repeat the calculations for compliance years 2014/15 and 2015/16. Since that calculation has not been performed, no result is presented for your consideration in this report.

Section 5.4.3 Externality benefits due to solar PV carve-out

Externality benefits of the RPS, which are described in more detail below, totaled $20,083,294, or 2.94 percent of the Total Retail Costs of Electricity in CY 2015/16. I apportioned 16.01 percent of these benefits to solar PV based on the ratio of MWh generated of solar PV to all renewable energy generated during the compliance year. (Appendix 4) The solar PV portion of the externality benefits totaled $3,215,949, or 0.47 percent of the total retail cost of electricity.

Section 5.4.4 Economic impacts of the deployment of renewable energy in Delaware.

The Division, working with the Delaware Solar Energy Coalition, has surveyed the solar energy industry to determine the jobs impact of the industry in Delaware. We used an online tool to ensure anonymity. The survey report that 326 jobs in Delaware with total salaries of $17,410,375. Of those, the survey reports that 254 jobs serve the Delaware market. (Appendix 9) The survey included a question about anticipated jobs losses if the RPS was included in the survey in response to comments we received earlier this year. The survey found that 143 jobs would be lost if the RPS were frozen, with a lost salaries of $7,637,066. It should be noted that this is a more conservative approach than was used in the previous survey, and thus the economic impact is lower than was previously reported.

The IMPLAN analysis performed earlier this year resulted in a total multiplier effect (total direct, indirect and induced economic benefits) of 1.58 times salaries. (Appendix 10) When the same multiplier is applied to the total amount of salary lost if the RPS were frozen, the direct, indirect and induced effects total $12,040,396.

The preliminary results summarized below show that the benefits of the solar PV carve-out exceed the cost of compliance:

Solar PV	Cost in $	% of Retail
Total Retail Costs of Electricity	$ 682,403,734	
GEF used to support PV	$ 1,950,730	
DPL SREC procurement	$ 6,787,614	
Solar Cost of Compliance	$ 8,738,344	1.28%
Offsets		
Market conditions	n/a	n/a
Avoided costs capacity in MW	n/a	n/a
Avoided costs energy in MWh	n/a	n/a
Externalities NOx and SO2	$ 2,349,134	0.34%
Externalities CO2	$ 866,815	0.13%
Economic impacts	$ 12,040,396	1.76%
Total offsets	$ 15,256,344	2.24%
Net Cost (Benefit) of PV Compliance	$ (6,518,000)	-0.96%

Conclusion

The incomplete calculations of the externality benefits and the economic benefits of the solar PV used to satisfy DPL's solar carve-out totaled 2.24 percent, which is greater than the 1.28 percent

cost of solar PV compliance. Therefore, based on the Regulation, we reasonably expect to recommend that you as Director would be justified in deciding not to freeze the solar carve-out.

RPS Costs and Benefits

I have calculated the RPS cost of compliance is calculated as follows:

Section 4.2 Renewable Energy Cost of Compliance

The Cost of RPS Compliance in Compliance Year 2014/15 was $32,035,895, or 4.69 percent of the total retail cost of electricity. (Appendix 3) The statute gives the Director discretion, in consultation with the PSC, to decide whether to freeze the RPS. Section 5.0 of the Regulation directs how the Director will make a determination of whether to freeze the RPS.

I have analyzed the following benefits to be considered in a determination as follows:

Section 5.4.1 Overall energy market conditions

Overall market energy conditions have not changed sufficiently enough to significantly affect this analysis.

Section 5.4.2 Avoided cost benefits from the RPS

Avoided cost benefits are described in more detail above. Since that calculation is provisional and has not been performed for CY 2015/16, no result is presented for your consideration in this report.

Section 5.4.3 Externality benefits due to the RPS

Delmarva Power calculated the externality benefits of renewable energy in its 2014 Integrated Resource Plan (IRP). This externality benefit calculation incorporates the avoided mortality costs for NOx and SO2 and the social cost of CO2 emissions. DPL calculated the externality benefits of reduced emissions of NOx and SO2 due to renewable energy in Delaware to be $14,670,119 based on the assumption that renewable energy displaced 50 percent of the PJM generation mix (which can be considered a conservative estimate due to the efficiency of the grid). (Appendix 6, p. 79)

The cost of CO2 is calculated to be $5,413,175. DPL, in the 2014 IRP, set the cost of CO2 to be $1 per metric ton, the low end of the EPA/OMB range of the social cost of carbon (SCC). This report uses the EPA/OMB calculations of social cost of carbon (SCC), which were updated in July, 2015. I took the figure of $38.00 per metric ton for 2015, which assumes a 3.0 percent discount rate of future costs in 2007 dollars. (Appendix 7) The figure in 2007 dollars has been adjusted using the CPI (Appendix 8), resulting in a SCC of $32.75 in 2016 dollars. As with DPL's externality calculations, it is assumed that renewable energy displaced 50 percent of the PJM generation mix.

The Regulation includes "improvements to habitat" as part of the definition of externality benefits. We have not developed methods for calculating habitat benefits of renewable energy.

Externality benefits of the RPS in Delaware in CY 2015/16 totaled $20,083,294, or 2.94 percent of the total retail costs of electricity.

Section 5.4.4 Economic impacts of the deployment of renewable energy in Delaware.

The economic impacts of solar PV in Delaware are described above.

The results summarized below clearly show that the benefits are nearly equal to the cost of compliance:

All Renewable Resources	Cost in $	% of Retail
Total Retail Costs of Electricity	$ 682,403,734	
GEF to support renewable resources	$ 1,950,730	
DPL REC and SREC procurement	$ 30,085,165	
Renewable Energy Cost of Compliance	$ 32,035,895	4.69%
Offsets		
Market conditions	n/a	n/a
Avoided costs capacity in MW	n/a	n/a
Avoided costs energy in MWh	n/a	n/a
Externalities NOx and SO2	$ 14,670,119	2.15%
Externalities CO2	$ 5,413,175	0.79%
Economic impacts	$ 12,040,396	1.76%
Total offsets	$ 32,123,690	4.71%
Net Cost (Benefit) of RPS Compliance	$ (87,795)	-0.01%

Conclusion

These provisional calculations of externality benefits and economic benefits of renewable energy used to satisfy DPL's RPS requirement total 4.71 percent, compared to the cost of compliance of 4.69 percent. In other words, the benefits are nearly equal to the cost of compliance. Therefore, based on the Regulation, we reasonably expect to report that you would be justified in deciding not to freeze the RPS.

Appendices:

1. Renewable Energy Portfolio Standards Act (REPSA), 26 *Del. C.* Subchapter III-A. Renewable Energy Portfolio Standards

2. Regulation 104 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions

3. DPL RPS Report for Compliance Year 2015/16

4. RPS Costs and Benefits worksheet, Division of Energy & Climate, October 2016

5. "Delaware Solar PV LMP and Capacity Cap Analysis", John Nangle, Kim Peterson & Blaise Stoltenberg, National Renewable Energy Laboratory, November 2014

6. *2014 Integrated Resource Plan*, Delmarva Power, December 2014, pp. 76-90, with Appendices 1-3

7. *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, Interagency Working Group on Social Cost of Carbon, United States Government, Revised July 2015

8. US Department of Labor, CPI Detailed Report

9. Delaware solar industry survey results, October 2016

10. IMPLAN results on solar PV jobs in Delaware

Appendix 1

Title 26

delcode.delaware.gov/title26/c001/sc03/index.shtml

TITLE 26

Public Utilities

CHAPTER 1. PUBLIC SERVICE COMMISSION

Subchapter III-A. Renewable Energy Portfolio Standards

§ 351 Short title; declaration of policy.

(a) This subchapter shall be known and may be cited as the "Renewable Energy Portfolio Standards Act."

(b) The General Assembly finds and declares that the benefits of electricity from renewable energy resources accrue to the public at large, and that electric suppliers and consumers share an obligation to develop a minimum level of these resources in the electricity supply portfolio of the state. These benefits include improved regional and local air quality, improved public health, increased electric supply diversity, increased protection against price volatility and supply disruption, improved transmission and distribution performance, and new economic development opportunities.

(c) It is therefore the purpose and intent of the General Assembly in enacting the Renewable Energy Portfolio Standards Act to establish a market for electricity from these resources in Delaware, and to lower the cost to consumers of electricity from these resources.

75 Del. Laws, c. 205, § 1.;

§ 352 Definitions.

As used in this subchapter:

(1) "Alternative compliance payment" means a payment of a certain dollar amount per megawatt hour, which a retail electricity supplier or municipal electric company may submit in lieu of supplying the minimum percentage from Eligible Energy Resources required under Schedule I in § 354 of this title.

(2) "Commission" means the Delaware Public Service Commission.

(3) "Compliance year" means the calendar year beginning with June 1 and ending with May 31 of the following year, for which a retail electricity supplier or municipal electric company must demonstrate that it has met the requirements of this subchapter.

(4) "Customer-sited generation" means a generation unit that is interconnected on the end-use customer's side of the retail electricity meter in such a manner that it displaces all or part of the metered consumption of the end-use customer.

(5) "DNREC" means Delaware Department of Natural Resources and Environmental Conservation.

(6) "Eligible energy resources" include the following energy sources located within or imported into the PJM region:

a. Solar photovoltaic or solar thermal energy technologies that employ solar radiation to produce electricity or to displace electricity use;

b. Electricity derived from wind energy;

c. Electricity derived from ocean energy including wave or tidal action, currents, or thermal differences;

d. Geothermal energy technologies that generate electricity with a steam turbine, driven by hot water or steam extracted from geothermal reservoirs in the earth's crust;

e. Electricity generated by a fuel cell powered by renewable fuels;

f. Electricity generated by the combustion of gas from the anaerobic digestion of organic material;

g. Electricity generated by a hydroelectric facility that has a maximum design capacity of 30 megawatts or less from all generating units combined that meet appropriate environmental standards as determined by DNREC;

h. Electricity generated from the combustion of biomass that has been cultivated and harvested in a sustainable manner as determined by DNREC, and is not combusted to produce energy in a waste to energy facility or in an incinerator, as that term is defined in Title 7;

i. Electricity generated by the combustion of methane gas captured from a landfill gas recovery system; provided however, that:

1. Increased production of landfill gas from production facilities in operation prior to January 1, 2004, demonstrates a net reduction in total air emissions compared to flaring and leakage;

2. Increased utilization of landfill gas at electric generating facilities in operation prior to January 1, 2004;

A. Is used to offset the consumption of coal, oil, or natural gas at those facilities;

B. Does not result in a reduction in the percentage of landfill gas in the facility's average annual fuel mix when calculated using fuel mix measurements for 12 out of any continuous 15-month period during which the electricity is generated; and

C. Causes no net increase in air emissions from the facility; and

3. Facilities installed on or after January 1, 2004, meet or exceed 2004 federal and state air emission standards, or the federal and state air emission standards in place on the day the facilities are first put into operation, whichever is higher.

(7) "End-use customer" means a person or entity in Delaware that purchases electrical energy at retail prices from a retail electricity supplier or municipal electric company.

(8) "Fund" means the Delaware Green Energy Fund.

(9) "GATS" means the generation attribute tracking system developed by PJM.

(10) "Generation attribute" means a nonprice characteristic of the electrical energy output of a generation unit including, but not limited to, the unit's fuel type, geographic location, emissions, vintage and RPS eligibility.

(11) "Generation unit" means a facility that converts a fuel or an energy resource into electrical energy.

(12) "Municipal electric company" means a public corporation created by contract between 2 or more municipalities pursuant to provisions of Chapter 13 of Title 22 and the electric utilities that are municipally owned within the State of Delaware.

(13) "New renewable generation resources" means eligible energy resources first going into commercial operation after December 31, 1997.

(14) "PJM" or "PJM interconnection" means the regional transmission organization (RTO) that coordinates the movement of wholesale electricity in the PJM region, or its successors at law.

(15) "PJM region" means the area within which the movement of wholesale electricity is coordinated by PJM Interconnection. The PJM region is as described in the Amended and Restated Operating Agreement of PJM.

(16) "Qualified fuel cell provider" means an entity that

a. By no later than the commencement date of commercial operation of the full nameplate capacity of a fuel cell project, manufactures fuel cells in Delaware that are capable of being powered by renewable fuels, and

b. Prior to approval of required tariff provisions, is designated by the Director of the Delaware Economic Development Office and the Secretary of DNREC as an economic development opportunity.

(17) "Qualified fuel cell provider project" means a fuel cell power generation project located in Delaware owned and/or operated by a qualified fuel cell provider under a tariff approved by the Commission pursuant to § 364(d) of this title.

(18) "Renewable energy credit" ("REC") means a tradable instrument that is equal to 1 megawatt-hour of retail electricity sales in the State that is derived from eligible energy resources and that is used to track and verify compliance with the provisions of this subchapter.

(19) "Renewable energy portfolio standard" and "RPS" means the percentage of electricity sales at retail in the state that is to be derived from eligible energy resources.

(20) "Renewable fuel" means a fuel that is derived from eligible energy resources. This term does not include a fossil fuel or a waste product from a fossil fuel source.

(21) "Retail electricity product" means an electrical energy offering that is distinguished by its generation attributes and that is offered for sale by a retail electricity supplier or municipal electric company to end-use customers.

(22) "Retail electricity supplier" means a person or entity that sells electrical energy to end-use customers in Delaware, including but not limited to nonregulated power producers, electric utility distribution companies supplying standard offer, default service, or any successor service to end-use customers. A retail electricity supplier does not include a municipal electric company for the purposes of this subchapter.

(23) "Rural electric cooperative" means a nonstock, nonprofit, membership corporation organized pursuant to the federal Rural Electrification Act of 1936 [7 U.S.C § 901 et seq.] and operated under the cooperative form of ownership.

(24) "Solar Alternative Compliance Payment" means a payment of a certain dollar amount per megawatt-hour, which a retail electricity supplier or municipal electric supplier may submit in lieu of supplying the

minimum percentage from solar photovoltaics required under Schedule I in § 354 of this title.

(25) "Solar Renewable Energy Credit" ("SREC") means a tradable instrument that is equal to 1 megawatt-hour of retail electricity sales in the State that is derived from solar photovoltaic energy resources and that is used to track and verify compliance with the provisions of this subchapter.

(26) "Total retail sales" means retail sales of electricity within the State of Delaware exclusive of sales to any industrial customer with a peak demand in excess of 1,500 kilowatts.

§ 353 Renewable energy portfolio standards administration.

(a) The Delaware Public Service Commission shall determine, verify, and assure compliance with renewable energy portfolio standards established pursuant to this subchapter that apply to all retail electricity sales in the State, except retail electricity sales of municipal electric companies. Any rural electric cooperative that is opted-out of Commission regulation by its membership pursuant to § 223 of this title shall, for all purposes of administering and applying the provisions of this subchapter, be treated as a municipal electric company during any period of time that the rural electric cooperative is exempt from Commission regulation.

(b) The Commission shall implement renewable energy portfolio standards pursuant to this subchapter that apply to all retail electricity sales in the state except sales to any industrial customer with a peak demand in excess of 1,500 kilowatts.

(c) The Commission shall develop rules to transition the REC and SREC procurement responsibility set forth in § 354(e) of this title. The purpose of such rules shall be:

(1) To adequately protect electric suppliers that entered into contracts to provide RECs and SRECs to retail electric customers prior to the transition of REC and SREC procurement responsibility under § 354(e) of this title;

(2) To adequately protect against overpayment of the cost of RPS obligations for customers of electric suppliers who are parties to supply contracts that were entered into prior to the transition of REC and SREC procurement responsibility under § 354(e) of this title; and

(3) To adequately protect commission-regulated electric suppliers and customers thereof from having to incur alternative compliance payments or other costs that would have been avoided but for the failure of an electric supplier to continue retiring RECs or SRECs associated with its retail supply contracts existing at the time of the transition of REC and SREC procurement responsibility under § 354(e) of this title. To the extent such protection involves a temporary reduction to the RPS obligation or to the price of an alternative compliance payment required of a commission-regulated electric supplier made necessary by the failure described above, the Commission is authorized to make the necessary temporary reductions notwithstanding the RPS obligations otherwise required by this chapter.

(d) The Commission shall develop procedures for tracking the generation output of qualified fuel cell provider projects such that energy produced by such projects shall fulfill the commission-regulated electric company's state- mandated REC and SREC requirements set forth in § 354 of this title as follows:

(1) Fulfillment of the equivalent of 1 REC for each megawatt-hour of energy produced by a qualified fuel cell provider project.

a. The commission-regulated electric company can use energy output produced by a qualified fuel cell provider project to fulfill a portion of SREC requirements at a ratio of 6MWH of RECs per 1MWH of SRECs. The commission-regulated electric company may utilize a portion of energy output from a

qualified fuel cell provider project in any given year to fulfill no more than 30% of the SREC requirements unless:

1. Due to lack of SREC availability in the market, the alternative would be to incur alternative compliance payments; or

2. The SREC obligations set forth in Schedule I of § 354 of this title are increased, and then only to the extent necessary to fulfill the increased SREC obligations.

b. The Secretary of DNREC may, after coordination with the Commission and a commission-regulated electric company, adjust the requirements of this section including permitting a commission-regulated electric company participating in a commission-approved project to exceed the percentages set forth in this section.

c. The right of a commission-regulated electric company to use energy output produced by a qualified fuel cell provider project to fulfill its REC and SREC requirements in accordance with this section shall not expire until actually applied to fulfill such requirements.

(2) The commission-regulated electric company has the ability to apply the REC and SREC equivalent fulfillment benefits described in this section for 20MW in addition to the 30MW set forth in § 364 of this title for future customer sited applications of qualified fuel cell provider fuel cells. Separate tariff provisions must first be approved by the Commission for such installations above the original 30MW.

75 Del. Laws, c. 205, § 1; 78 Del. Laws, c. 99, § 2.;

§ 354 Renewable energy portfolio standards, eligible energy resources and industrial exemption.

(a) The total retail sales of each Retail Electricity Product delivered to Delaware end-use customers by a retail electricity supplier or municipal electric company during any given compliance year shall include a minimum percentage of electrical energy sales with eligible energy resources and solar photovoltaics as follows:

SCHEDULE I

Compliance Year (beginning June 1st)	Minimum Cumulative Percentage from Eligible Energy Resources	Minimum Cumulative Percentage from Solar Photovoltaics*
2010	5.00%	0.018%
2011	7.00%	0.20%
2012	8.50%	0.40%
2013	10.00%	0.60%
2014	11.50%	0.80%
2015	13.00%	1.00%
2016	14.50%	1.25%
2017	16.00%	1.50%
2018	17.50%	1.75%
2019	19.00%	2.00%

Compliance Year (beginning June 1st)	Minimum Cumulative Percentage from Eligible Energy Resources	Minimum Cumulative Percentage from Solar Photovoltaics*
2020	20.00%	2.25%
2021	21.00%	2.50%
2022	22.00%	2.75%
2023	23.00%	3.00%
2024	24.00%	3.25%
2025	25.00%	3.50%

* Minimum Percentage from Eligible Energy Resources Includes the Minimum Percentage from Solar Photovoltaics.

Any portion of a retail electricity supplier's renewable energy supply portfolio for 2007, 2008 and 2009 compliance years that is acquired under wholesale renewable energy supply entered into pursuant to the 2005 or 2006 Delaware Standard Offer Service (SOS) auctions shall be subject to the provisions of this subchapter, as set forth in Schedule I (Revised) below that were in effect on the date of the 2005 or 2006 SOS auction:

SCHEDULE I (Revised)

Compliance Year (beginning June 1st	Minimum Cumulative Percentage from Solar Photovoltaics	Minimum Cumulative Percentage from Eligible Energy Resources*
2007	—	1.00%
2008	0.011%	1.50%
2009	0.014%	2.00%
2010	0.018%	5.00%
2011	0.048%	7.00%
2012	0.099%	8.50%
2013	0.201%	10.00%
2014	0.354%	11.50%
2015	0.559%	13.00%
2016	0.803%	14.50%
2017	1.112%	16.00%
2018	1.547%	18.00%
2019	2.005%	20.00%

* Minimum Percentage from Eligible Energy Resources Includes the Minimum Percentage from Solar Photovoltaics.

(b) Cumulative minimum percentage requirements of eligible energy resources and solar photovoltaics

shall be established by Commission rules for compliance year 2026 and each subsequent year. In no case shall the minimum percentages established by Commission rules be lower than those required for compliance year 2025 in Schedule I, subsection (a) of this section. Each of the rules setting such minimum percentage shall be adopted at least 2 years prior to the minimum percentage being required.

(c) Beginning in compliance year 2010, and in each compliance year thereafter, the Commission may review the status of Schedule I and report to the legislature on the status of the pace of the scheduled percentage increases toward the goal of 25% from eligible energy resources. If the Commission concludes at this time that the schedule either needs to be accelerated or decelerated, it may also make recommendations to the General Assembly for legislative changes to the RPS.

(d) Beginning in compliance year 2014, and in each compliance year thereafter, the Commission may, in the event of circumstances specified in this subsection and after conducting hearings, accelerate or slow the scheduled percentage increases towards meeting the goal of 25%. The Commission may only slow the increases if the Commission finds that at least 30% of RPS compliance has been met through the alternative compliance payment for 3 consecutive years, despite adequate planning by the commission-regulated electric companies and, where applicable, the retail electricity suppliers with existing contractual electric supply obligations. The Commission may only accelerate the scheduled percentage increases after finding that the average price for renewable energy credits eligible for RPS compliance has, for 2 consecutive years, been below a predetermined market-based price threshold to be established by the Commission. The Commission shall establish the predetermined market-based price threshold in consultation with the Delaware Energy Office. Rules that would alter the percentage targets shall be promulgated at least 2 years before the percentage change takes effect. In no event shall the Commission reduce the percentage target below any level reached to that point.

(e) Beginning with compliance year 2012, commission-regulated electric companies shall be responsible for procuring RECs, SRECs and any other attributes needed to comply with subsection (a) of this section with respect to all energy delivered to such companies' end use customers.

(f) For each commission-regulated electric company, retail electricity supplier with existing contractual electric supply obligation or municipal electric company, no more than 1% of each year's total retail sales may be met from eligible energy resources that are not new renewable generation resources. In compliance year 2026, and for each compliance year thereafter, all eligible energy resources used to meet cumulative minimum percentage requirements set by the Commission rules shall be new renewable generation resources.

(g) A retail electricity supplier or municipal electric company shall not use energy used to satisfy another state's renewable energy portfolio requirements for compliance with Schedule I of subsection (a) of this section.

(h) An applicant's compliance with Schedule I of subsection (a) of this section shall be based on historical data, collected in a manner consistent with industry standard and, with respect to retail electricity suppliers, Commission regulations. A retail electricity supplier or municipal electric company shall meet the renewable energy portfolio standards by accumulating the equivalent amount of renewable energy credits and solar renewable energy credits that equal the percentage required under this section.

(i) The State Energy Coordinator in consultation with the Commission, may freeze the minimum cumulative solar photovoltaics requirement for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement during a compliance year exceeds 1% of the total retail cost of electricity for retail electricity suppliers during the same compliance year. In the event of a freeze, the minimum cumulative percentage from solar photovoltaics shall remain at the percentage for the year in which the freeze is instituted. The freeze shall be lifted upon a finding by the Coordinator, in

consultation with the Commission, that the total cost of compliance can reasonably be expected to be under the 1% threshold. The total cost of compliance shall include the costs associated with any ratepayer funded state solar rebate program, SREC purchases, and solar alternative compliance payments.

(j) The State Energy Coordinator in consultation with the Commission, may freeze the minimum cumulative eligible energy resources requirement for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement during a compliance year exceeds 3% of the total retail cost of electricity for retail electricity suppliers during the same compliance year. In the event of a freeze, the minimum cumulative percentage from eligible energy resources shall remain at the percentage for the year in which the freeze is instituted. The freeze shall be lifted upon a finding by the Coordinator, in consultation with the Commission, that the total cost of compliance can reasonably be expected to be under the 3% threshold. The total cost of compliance shall include the costs associated with any ratepayer funded state renewable energy rebate program, REC purchases, and alternative compliance payments.

75 Del. Laws, c. 205, § 1 ; 76 Del. Laws, c. 165, §§ 4(a), (b), 5 ; 77 Del. Laws, c. 451, §§ 1, 2, 4-11 ; 78 Del. Laws, c. 99, §§ 3-6.;

§ 355 Renewable energy credits.

(a) Energy sold or displaced by customer-sited generation on or after June 1, 2006, may be used to create and accumulate renewable energy credits for the purposes of calculating compliance with the renewable energy portfolio standards established pursuant to this subchapter.

(b) Energy production from customer-sited eligible energy resource may also be used to demonstrate compliance, provided that the facilities are physically located in Delaware.

(c) Aggregate generation from small eligible energy sources, 100 kilowatts of capacity or less, may be used to meet the requirements of Schedule I of § 354(a) of this title, provided that the generators or their agents document the level of generation, as recorded by appropriate metering and power sales, on an annual basis.

75 Del. Laws, c. 205, § 1.;

§ 356 Multiple credits for specific energy sources.

(a) A retail electricity supplier or municipal electric company shall receive 300% credit toward meeting the minimum percentage from Eligible Energy Resources of Schedule I of the renewable energy portfolio standards established pursuant to this subchapter for energy derived from the following sources installed on or before December 31, 2014:

(1) Customer-sited solar photovoltaic physically located in Delaware; or

(2) A fuel cell powered by renewable fuels.

(b) A retail electricity supplier or municipal electric company shall receive 150% credit toward meeting the renewable energy portfolio standards established pursuant to this subchapter for wind energy installations sited in Delaware on or before December 31, 2012.

(c) A Commission-regulated electric company shall receive 350% credit toward meeting the renewable energy portfolio standards established pursuant to this subchapter for energy derived from off-shore wind energy installations sited off the Delaware coast on or before May 31, 2017.

(1) To be entitled to 350% credit, contracts for energy and renewable energy credits from such off-shore

wind energy installations must be executed by Commission-regulated electric companies prior to commencement of construction of such installations.

(2) Commission-regulated electric companies shall be entitled to such multiple credits for the life of contracts for renewable energy credits from off-shore wind installations executed pursuant to this subsection.

(d) A retail electricity supplier shall receive an additional 10% credit toward meeting the renewable energy portfolio standards established pursuant to this subchapter for solar or wind energy installations sited in Delaware provided that a minimum of 50% of the cost of renewable energy equipment, inclusive of mounting components, are manufactured in Delaware.

(e) A retail electricity supplier shall receive an additional 10% credit toward meeting the renewable energy portfolio standards established pursuant to this subchapter for solar or wind energy installations sited in Delaware provided that the facility is constructed and/or installed with a minimum of 75% in-state workforce.

§ 357 Proportional credit for eligible landfill gas and biogas.

A retail electricity supplier or municipal electric company shall receive credit toward meeting renewable energy portfolio standards established pursuant to this subchapter for electricity derived from the fraction of eligible landfill gas or biogas combined with other fuels.

75 Del. Laws, c. 205, § 1.;

§ 358 Issuance of renewable energy credits; reporting requirement; alternative compliance payment.

(a) The Commission shall establish by regulation the mechanisms under which a REC and SREC shall be created and recorded with respect to the entity generating electricity using eligible energy resources for use in complying with the renewable energy portfolio standards of this subchapter. Once the GATS system is operational and the PJM Interconnection, or a related organization currently known as PJM Environmental Services, Inc. (PJM-ESI), begins issuing RECs and SRECs, the Commission may issue an order approving the use of RECs and SRECs issued by the PJM Interconnection or PJM-ESI for compliance with the renewable energy portfolio Standards of this subchapter.

(b) Beginning June 1, 2007, each retail electricity supplier shall submit an annual report to the Commission, on a form and by a date specified by the Commission, that:

(1) Demonstrates that the retail electricity supplier has complied with the renewable energy portfolio standards established pursuant to this subchapter and includes the submission of the required amount of renewable energy credits; or

(2) Demonstrates the amount of electricity sales for the compliance year by which the retail electricity supplier failed to meet the renewable energy portfolio standard.

(c) Beginning June 1, 2007, each municipal electric company shall submit an annual report to the Delaware Energy Office and the Controller General that:

(1) Demonstrates that the municipal electric company has complied with the RPS established pursuant to this subchapter and includes the submission of the required amount of renewable energy credits; or

(2) Demonstrates the amount of electricity sales for the compliance year by which the municipal electric company failed to meet the RPS.

(d) In lieu of standard means of compliance with this statute, any retail electricity supplier may pay into the Fund an alternative compliance payment of $25 for each megawatt-hour deficiency between the credits available and used by a retail electricity supplier in a given compliance year and the credits necessary for such retail electricity supplier to meet year's renewable energy portfolio standard. A municipal electric company may pay the alternative compliance payment into a fund established by its municipal members. In subsequent years, the alternative compliance payments for any retail electricity supplier or municipal electricity company shall increase as follows:

(1) If a retail electricity supplier has paid an alternative compliance payment of $25 for each megawatt-hour in any previous year, then the alternative compliance payment shall be $50 for each megawatt-hour.

(2) If a retail electricity supplier has paid an alternative compliance payment of $50 for each megawatt-hour in any previous year, then the alternative compliance payment shall be $80 for each megawatt-hour.

(3) Alternative compliance payments shall not be more than $80 for each megawatt-hour.

(4) The State Energy Coordinator shall have the authority to review the alternative compliance payment on an as needed or annual basis to determine reasonableness compared to market REC prices. Following an analysis conducted by the Delaware Energy Office, the State Energy Coordinator shall also have the authority to adjust the alternative compliance payment by 10% in order to achieve reasonableness.

(e) In lieu of standard means of compliance with this statute, any retail electricity supplier may pay into the Fund a Solar Alternative Compliance Payment of $400 for each megawatt-hour deficiency between the credits available and used by a retail electricity supplier in a given compliance year and the credits necessary for such retail electricity supplier to meet the year's Renewable Energy Portfolio Standard. A municipal electric company may pay the solar alternative compliance payment into a fund established by its municipal members. In subsequent years, the solar alternative compliance payments for any retail electricity supplier or municipal electricity company shall increase as follows:

(1) If a retail electricity supplier has paid a Solar Alternative Compliance Payment of $400 for each megawatt-hour in any previous year, then the solar alternative compliance payment shall be $450 for each megawatt-hour.

(2) If a retail electricity supplier has paid a Solar Alternative Compliance Payment of $450 for each megawatt-hour in any previous year, then the Solar Alternative Compliance Payment shall be $500 for each megawatt-hour.

(3) The State Energy Coordinator shall have the authority to review the Solar Alternative Compliance Payment on an as needed or annual basis to determine reasonableness compared to market-based SREC prices. Following an analysis conducted by the Delaware Energy Office, the State Energy Coordinator shall also have the authority to adjust the Solar Alternative Compliance Payment by 20% in order to achieve reasonableness, but not higher than 20% of the competitive market cost of an SREC, determined by the quarterly weighted average cost of meeting the requirement through purchase of an SREC as analyzed by the Delaware Energy Office.

(f)(1) *Recovery of costs* — A retail electricity supplier or municipal electric company may recover, through a nonbypassable surcharge, actual dollar for dollar costs incurred in complying with a state mandated renewable energy portfolio standard, except that any compliance fee assessed pursuant to subsection (d) of this section shall be recoverable only to the extent authorized by paragraph (f)(2) of this section.

(2) A retail electricity supplier or municipal electric company may recover any alternative compliance payment if:

a. The payment of an alternative compliance payment is the least cost measure to ratepayers as compared to the purchase of eligible energy resources to comply with a renewable energy portfolio standard; or

b. There are insufficient eligible energy resources available for the electric supplier to comply with a renewable energy portfolio standard.

(3) Any cost recovered under this section shall be disclosed to customers at least annually on inserts accompanying customer bills.

§ 359 Renewable energy tracking system.

(a) The Commission shall establish, maintain or participate in a market-based renewable energy tracking system to facilitate the creation, and transfer of renewable energy credits among retail electricity suppliers. A municipal electric company may elect to participate in the tracking system established by the Commission and may elect to participate in the GATS system once it is operational.

(b) The Commission may contract with a for-profit or a nonprofit entity to administer, or assist in the administration of, the renewable energy tracking system required pursuant to this section.

(c) The renewable energy tracking system shall include a registry of information regarding all:

(1) Available renewable energy credits; and

(2) Renewable energy credit transactions among electric suppliers in the State, including:

a. The creation and application of renewable energy credits; and

b. The number of renewable energy credits sold or transferred.

(d) The renewable energy tracking system registry shall provide current aggregated information to retail electricity suppliers and the public on the status of renewable energy credits created, sold, or transferred in the State. Information contained in the renewable energy tracking system registry shall be available by computer network access through the Internet; provided, however, that the Commission may establish reasonable limitation on the disclosure of commercially-sensitive information.

75 Del. Laws, c. 205, § 1.;

§ 360 Renewable energy trading.

(a) A retail electricity supplier or municipal electric company may use accumulated renewable energy credits or solar renewable energy credits to meet the renewable energy portfolio standard established pursuant to this subchapter, and may sell or transfer any renewable energy credit or solar renewable energy credit not needed to meet said standards.

(b) An unused renewable energy credit or solar renewable energy credit shall exist for 3 years from the date created.

(c) The 3-year period referred in subsection (b) of this section above shall be tolled during any period that a renewable energy credit or solar renewable energy credit is held by the SEU as defined in § 8059 of Title 29.

(d) The Renewable Energy Taskforce shall be formed for the purpose of making recommendations about the establishment of trading mechanisms and other structures to support the growth of renewable energy

markets in Delaware.

(1) The Taskforce shall comprise the following appointments:

a. Four appointments by the Secretary of DNREC, which shall include 1 representative from the renewable energy research and development industry, 1 representative from the local renewable energy manufacturing industry, and 1 representative from an environmental advocacy organization;

b. One appointment by the Commission;

c. One appointment by Delmarva Power & Light;

d. One appointment by the Delaware Electric Cooperative;

e. One appointment by municipal electric companies;

f. One appointment by the Sustainable Energy Utility;

g. One appointment by the Delaware Public Advocate; and

h. One appointment by the Delaware Solar Energy Coalition.

(2) The Taskforce shall be charged with making recommendations about and reporting on the following and matters related thereto:

a. Establishing balanced markets mechanisms for REC and SREC trading;

b. Establishing REC and SREC aggregation mechanisms and other devices to encourage the deployment of renewable, distributed renewable, and solar energy technologies in Delaware with the least impact on retail electricity suppliers, municipal electric companies and rural electric cooperatives;

c. After an analysis by the Taskforce, the annual progress towards achieving the minimum cumulative percentages for all renewable energy resources including, but not limited to, solar and other eligible energy resources and making appropriate recommendations based upon deliberate and factual analysis and study;

d. Minimizing the cost for complying with any portion of this subchapter based upon deliberate and factual analysis and study;

e. Establishing revenue certainty for appropriate investment in renewable energy technologies, including, but not limited to, consideration of long-term contracts and auction mechanisms;

f. Establishing mechanisms to maximize in-state renewable energy generation and local manufacturing; and

g. Ensuring that residential, commercial, and utility scale photovoltaic and solar thermal systems of various sizes are financially viable and cost-effective investments in Delaware.

(3) The Taskforce shall be formed by October 26, 2010, and be staffed by the Delaware Energy Office. The Taskforce shall make recommendations to the Commission, the Secretary of DNREC, the Board of Directors for rural electric cooperatives, and the pertinent local regulatory authorities on the abovementioned subjects for their consideration. Upon making these recommendations, the Commission, DNREC, the Board of Directors for rural electric cooperatives, or the pertinent local regulatory authorities, as appropriate, shall promulgate rules and regulations, or adopt policies, based on the Taskforce findings.

§ 361 Renewable energy credit transaction fee.

The Commission may impose an administrative fee on a retail electricity supplier with respect to a renewable energy credit transaction, but the amount of the fee may not exceed the Commission's actual direct cost of processing the transaction. If a municipal electric company opt to use the Commission's renewable energy credit tracking system, it shall be assessed the same transaction fees that the Commission assesses other retail electricity suppliers.

75 Del. Laws, c. 205, § 1.;

§ 362 Rules and regulations.

(a) The Commission shall adopt rules and regulations necessary to implement the provisions of this subchapter as it applies to retail electricity suppliers. The Commission shall make its regulations as consistent as possible with those of other states in the region with similar requirements in order to minimize the compliance burdens imposed by this statute and in order to avoid duplication of effort.

(b) For regulated utilities, the Commission shall further adopt rules and regulations to specify the procedures for freezing the minimum cumulative solar photovoltaic requirement as authorized under § 354(i) and (j) of this title, and for adjusting the alternative compliance payment and solar alternative compliance payment as authorized under § 358(d)(4) and (e)(3) of this title.

75 Del. Laws, c. 205, § 1; 77 Del. Laws, c. 451, § 20.;

§ 363 Special provisions for municipal electric companies and rural electric cooperatives.

(a) Any municipal electric company and any rural electric cooperative may elect to exempt itself from the requirements of this subchapter, if it develops and implements a comparable program to the renewable energy portfolio standards for its ratepayers beginning in 2013.

(b) In the event that a municipal electric company or rural electric cooperative elects to exempt itself from the requirements of this subchapter, it shall submit a plan at the beginning of 2013 to its local regulatory authority, the Delaware General Assembly, and the Delaware Energy Office detailing its approach to achieve a level of renewable energy penetration in its service territory, and shall submit an annual compliance report to its local regulatory authority, the Delaware General Assembly, and the Delaware Energy Office detailing its progress towards yearly targets.

(c) The Board of Directors for a rural electric cooperative or local regulatory authority of a municipal electric company shall base renewable energy portfolio standard decisions on the need, value and feasibility of the renewable energy resources pertaining to the economic and environmental well being of their members. The Board of Directors for a rural electric cooperative or local regulatory authority of a municipal electric company shall continue to evaluate all renewable energy resources including but not limited to: wind, biomass, hydroelectric and solar and submit an annual report to the General Assembly and their membership as to their determination.

(d) In the event that a municipal electric company or rural electric cooperative elects to exempt itself, it shall either contribute to the Green Energy Fund at levels commensurate with other retail electricity suppliers or create an independent, self-administered fund separate from the Green Energy Fund to be used in support of energy efficiency technologies, renewable energy technologies, or demand side management programs, into which it shall make payments of at least $0.178 for each megawatt-hour it sells, transmits, or distributes in this State.

(e) The total cost of compliance with this section shall include the costs associated with any ratepayer

funded renewable energy rebate programs, REC and SREC purchases, or other costs incurred in meeting renewable energy programs.

(f) The total cost of complying with eligible energy resources shall not exceed 3% of the total cost of the purchased power of the utility for any calendar year.

(g) The total cost of complying with the solar photovoltaic program shall not exceed 1% of the total cost of the purchased power of the affected utility for any calendar year.

(h) At no time during any calendar year shall the total cost of compliance with this section result in an increase of an average consumer's monthly bill in excess of 4%.

(i) The Board of Directors of a rural electric cooperative and the local regulatory authority of a municipal electric company may approve an increase in the limit on the cost of compliance, as specified in subsections (f) and (g) of this section above.

(j) In pursuit of their renewable energy goals, a municipal electric company or rural electric cooperative shall receive all appropriate multiple credits for specific energy sources, as established under §§ 356 and 357 of this title and sited in Delaware for the life of contracts for renewable energy credits.

75 Del. Laws, c. 205, § 1; 77 Del. Laws, c. 451, § 21.;

§ 364 Special provisions for Public Service Commission-regulated electric companies.

(a) All costs arising out of contracts entered into by a commission-regulated electric company pursuant to § 1007(d) of this title shall be distributed among the entire Delaware customer base of such companies through an adjustable nonbypassable charge which shall be established by the Commission. Such costs shall be recovered if incurred as a result of such contracts unless, after Commission review, any such costs are determined by the Commission to have been incurred in bad faith, are the product of waste or out of an abuse of discretion, or in violation of law.

(b) All funds disbursed to a qualified fuel cell provider project by a commission-regulated electric company, including incremental site preparation costs incurred by qualified fuel cell provider project, shall be collected from the entire Delaware customer base of such company through adjustable nonbypassable charges which shall be established by the Commission. A commission-regulated electric company participating in a qualified fuel cell provider project shall collect and disburse funds solely as the agent for the collection and disbursement of funds for the project and shall have no liability except to comply with the tariff provisions to be established as set forth in subsection (d) of this section.

(c) All miscellaneous costs arising out of qualified fuel cell provider projects incurred by a commission-regulated electric company, including, but not limited to, filing costs, administrative costs and incremental site preparation costs, shall be distributed among the entire Delaware customer base of such company through adjustable nonbypassable charges which shall be established by the Commission. Such costs shall be recovered unless, after Commission review, any such costs are determined by the Commission to have been incurred in bad faith, are the product of waste or out of an abuse of discretion, or in violation of law.

(d) Before a commission-regulated electric company may collect any charges on behalf of a qualified fuel cell provider project that would entitle the commission-regulated electric company to reduce its REC and SREC requirements as provided for in § 353(d) of this title, the Commission must adopt tariff provisions applicable to such project.

(1) Tariff provisions enabling and obligating commission-regulated electric companies, acting in the role of

an agent for collection and disbursement, to collect charges on behalf of a qualified fuel cell provider project shall be proposed jointly by the electric company and the qualified fuel cell provider and shall, at a minimum, provide for the following.

a. A project of 30MW nominal nameplate, and future potential additions of up to an additional 20MW nominal nameplate, not to exceed a total of 50MW nominal nameplate or 1,152 megawatt hours per day averaged on an annual basis. The total allowable 50MW of nominal nameplate shall be reduced by any customer sited installations referred to in § 353(d)(2) of this title or additional installations of qualified fuel cell provider fuel cells. Any additional MW beyond the 30MW project made pursuant to this section and § 353(d)(2) of this title must be reviewed and approved by the Commission.

b. A term of service of at least 20 years from commercial operation of the completed qualified fuel cell provider project.

c. The cost to customers of the commission-regulated electric company for each MWH of output produced by the project which, on a levelized basis at the time of Commission approval, does not exceed the highest cost source for combined energy, capacity and environmental attributes approved by the Commission for inclusion in the renewable portfolio of the commission-regulated electric company as of January 1, 2011.

d. Adjustments to funds to be collected from customers and distributed to the qualified fuel cell provider project that will also compensate the qualified fuel cell provider project for its costs of fuel to produce such output and that will reduce compensation to the qualified fuel cell provider project for any revenues received by the qualified fuel cell provider project for such output sold in the PJM or any successor market.

e. The requirement that the qualified fuel cell provider project must sell all energy, capacity, and ancillary services, produced by the project and any other output available or that becomes reasonably available to the qualified fuel cell provider project during the term of the project into the PJM or any PJM successor market. To the extent any additional output produced by the project, including but not limited to any product or environmental attribute from the project becomes available for sale in the PJM market, PJM successor market, or a market other than PJM or a PJM successor market, the qualified fuel cell provider project and commission-regulated electric company shall jointly propose additional provisions to the tariff designed to reduce the cost of the qualified fuel cell provider project to customers of the commission-regulated electric company.

f. The commission-regulated electric company shall, on behalf of a qualified fuel cell provider project, collect from its customers, through a nonbypassable charge provided for in subsections (b) and (c) of this section, any positive difference between the sum of:

1. The price for each MWH of output produced by the project plus

2. The cost of fuel to produce such output plus

3. Any costs incurred by the commission-regulated electric company arising out of the qualified fuel cell provider project minus the amount received by the qualified fuel cell provider project for the market sale of its output, and shall distribute such amount to the qualified fuel cell provider project.

g. That the commission-regulated electric company shall, on behalf of a qualified fuel cell provider project, distribute to its customers from the qualified fuel cell provider project, through a distribution mechanism to be established in a tariff, any positive difference between the amount received by the qualified fuel cell provider project for the market sale of its output minus the sum of:

1. The price established for each MWH of output from the project plus

2. The cost of fuel to produce such output plus

3. Any costs incurred by the commission-regulated electric company arising out of the qualified fuel cell provider project.

h. An average efficiency level that the fuel cells in a project must maintain.

i. A definition of the role of the commission-regulated electric company solely as the agent of a qualified fuel cell provider project, for the collection of funds and disbursement of such collected funds to qualified fuel cell provider project and to its customers.

j. The mechanism through which the commission-regulated electric company, on behalf of a qualified fuel cell provider project, shall collect from its customers, through a nonbypassable charge provided for in subsections (b) and (c) of this section, any difference between the sum of:

1. The price for each MWH of output produced by the project plus

2. The cost of fuel to produce such output plus

3. Any costs incurred by the commission-regulated electric company arising out of the qualified fuel cell provider project minus the amount received by the qualified fuel cell provider project for the market sale of its output.

k. The mechanism through which the commission-regulated electric company, on behalf of a qualified fuel cell provider project, shall distribute to its customers, through bill credits, any positive difference between the amount received by the qualified fuel cell provider project for the market sale of its output minus the sum of:

1. The price established for each MWH of output from the project plus

2. The cost of fuel to produce such output plus

3. Any costs incurred by the commission-regulated electric company arising out of the qualified fuel cell provider project.

l. A provision that protects a qualified fuel cell provider project from any future changes to this subchapter that would prevent a qualified fuel cell provider project that provides service under approved tariff provisions from recovering all amounts approved in such tariff. Such provision shall also include the obligation of the commission-regulated electric company, in the event of any such change to this subchapter, to collect from its customers amounts necessary to disburse, and to disburse to the qualified fuel cell provider project the full amount approved by the Commission in such preexisting tariff for each MWH of output produced by the qualified fuel cell provider project.

m. In the event of an event of force majeure that prevents the qualified fuel cell provider project from supplying output from at least 80% of the capacity of the qualified fuel cell provider project, or an interruption in fuel supply, in whole or in part, to the project, a mechanism through which,

1. During the event of force majeure, the commission-regulated electric company shall, on behalf of a qualified fuel cell provider project, collect from its customers and transfer to the qualified fuel cell provider project, a maximum of 70% of the price per MWH of output affected by the event of force majeure, and during an interruption in fuel supply, the commission-regulated electric company shall, on behalf of a qualified fuel cell provider project, collect from its customers and transfer to the qualified fuel cell provider project 100% of the price per MWH of output affected by the interruption.

2. During the event of force majeure or interruption in fuel supply, the commission-regulated electric company will continue to receive the full reduction in renewable portfolio standards that would have been provided by the output but for the event of force majeure or interruption in fuel supply.

(2) All tariff filings must be approved or denied by the Commission in whole, as proposed, without alteration or the imposition of any condition or conditions with respect thereto by the Commission. In determining whether to approve or deny the tariff, the Commission shall first ensure that the provisions of paragraphs (d)(1)a.-m. of this section have been satisfied. In addition, the Commission shall consider the incremental cost of the qualified fuel cell provider project to customers, applying at least the following factors:

a. Whether the qualified fuel cell provider project utilizes innovative baseload technologies,

b. Whether the qualified fuel cell provider project offers environmental benefits to the State relative to conventional baseload generation technologies,

c. Whether the qualified fuel cell provider project promotes economic development in the State, and

d. Whether the tariff as filed promotes price stability over the project term.

(3) A commission-regulated electric company and qualified fuel cell provider project may jointly modify proposed tariff provisions prior to any final ruling by the Commission.

(4) Notwithstanding § 306 of this title or any other provision of the Delaware Code to the contrary, any changes in rates or charges necessary to collect funds for disbursements or costs addressed in subsections (a)-(c) of this section through adjustable nonbypassable charges shall become effective 30 days after filing, absent a determination of manifest error by the Public Service Commission. The Commission may allow changes in rates or charges related to such adjustable nonbypassable charges to become effective less than 30 days after filing under such conditions as it may prescribe.

(5) Once approved by the Commission, such tariff provisions cannot be altered, nor may approval be repealed or modified, without the agreement of both the commission-regulated electric company and the qualified fuel cell provider project except that revisions to tariffs may be proposed by the commission-regulated electric company alone where:

a. Such revisions have no adverse effect on the qualified fuel cell provider project, and

b. Such revisions are for the purpose of complying with subsection (c) of this section.

(e) For purposes of this subchapter, all fuel cell units of a qualified fuel cell provider project under tariff with a commission-regulated electric company shall be considered to have been manufactured in Delaware as long as:

(1) By no later than the second anniversary of commercial operation of the full nameplate capacity of a fuel cell project, or December 31, 2016, whichever is earlier, either:

a. At least 80% of the installed nameplate capacity shall have been sourced from fuel cell units manufactured in a permanent manufacturing facility located in the State; or

b. No more than 10 megawatts of nameplate capacity from a fuel cell project shall be manufactured outside of the State; and

(2) Fuel cell manufacturer has executed an agreement with the Delaware Economic Development Office that a termination payment shall be made by the fuel cell manufacturer in the event that it ceases

manufacturing operations in the State.

(f) Notwithstanding any other provision of the Delaware Code to the contrary, amounts due to the qualified fuel cell provider project and amounts collected by the commission-regulated electric company on behalf a qualified fuel cell provider project as a result of a qualified fuel cell provider project, and any other costs incurred by a commission-regulated electric company addressed in subsections (a) through (c) of this section shall constitute revenue property when, and to the extent that, a tariff authorizing the revenue charges have become effective in accordance with this section, and the revenue property shall thereafter continuously exist as property for all purposes with all of the rights and privileges of this section for the period and to the extent provided in the tariff, but in any event until the end of the term of service of the qualified fuel cell provider project.

(g) Notwithstanding any other provision of the Delaware Code to the contrary, any requirement under this section or a tariff under this section requiring that the Commission take action with respect to the subject matter of a project under this section shall be binding upon the Commission, as it may be constituted from time to time, and any successor agency exercising functions similar to the Commission and the Commission shall have no authority to rescind, alter, or amend that requirement in a subsequent order except as provided in this chapter.

(h) Notwithstanding any other provision of the Delaware Code to the contrary except as otherwise provided in this chapter, with respect to revenue property, the tariffs with respect to disbursements and costs arising out of the qualified fuel cell provider project and recovery of costs addressed in subsections (a) through (c) of this section shall be irrevocable and the Commission shall not have authority either by rescinding, altering, or amending the tariff provisions or otherwise, to revalue or revise for ratemaking purposes the disbursements and costs arising out of the qualified fuel cell provider project, or the costs of recovering such costs, determine that the disbursements and costs of the qualified fuel cell provider project are unjust or unreasonable, or in any way reduce or impair the value of revenue property either directly or indirectly by taking project revenue amounts, disbursements or costs arising out of the qualified fuel cell provider project into account when setting other rates for the commission-regulated electric company; nor shall the disbursements, amount of revenues or costs arising with respect thereto be subject to reduction, impairment, postponement, or termination. Except as otherwise provided in this section, the State of Delaware does hereby pledge and agree with the owners of revenue property and the commission-regulated electric company as the agent for collecting and disbursement on behalf of a qualified fuel cell provider project and in collecting costs incurred by the electric company addressed in subsections (a) through (c) of this section that the State shall neither limit nor alter the revenue property and all rights thereunder until the obligations, are fully met and discharged, provided nothing contained in this section shall preclude the limitation or alteration if and when adequate provision shall be made by law for the full recovery by the qualified fuel cell provider project and the commission-regulated electric company.

(i) Notwithstanding § 201 of this title or any other provision of the Delaware Code to the contrary, the courts of this State shall have exclusive original jurisdiction over any dispute between a qualified fuel cell provider project and a commission-regulated electric company involving the interpretation of the obligations between them as contained in Commission approved tariffs required by subsection (d) of this section.

76 Del. Laws, c. 248, § 2; 78 Del. Laws, c. 99, §§ 7, 8.;

Cost of Compliance under 26 Del. C. § 354(i) & (j)
Preliminary Report for Compliance Year (CY) 2014/15
DRAFT - FOR DISCUSSION PURPOSES ONLY
This spreadsheet is intended to illustrate calculations under proposed cost cap regulation.
2-Feb-16

Estimated or preliminary figures are not included.

All Renewable Resources	Cost in $	% of Retail	Regulation	Notes
Total Retail Costs of Electricity	##########		Section 4.4	
GEF to support renewable resources	$ 2,391,217		Section 4.2.1	GEF expenditures in CY 2014/15
DPL REC and SREC procurement	$23,426,762		Section 4.2.2	DPL Compliance Report
Renewable Energy Cost of Compliance	$25,817,979	3.75%		
Offsets				
Market conditions	n/a	n/a	Section 5.4.1	No significantly sharp market fluctuations
Avoided costs capacity in MW	n/a	n/a	Section 5.4.2	
Avoided costs energy in MWh	n/a	n/a	Section 5.4.2	
Externalities NOx and SO2	$16,019,038	2.33%	Section 5.4.3	DPL 2012 IRP; 50% of PJM emissions avoided (3)
Externalities CO2	$ 7,273,018	1.06%	Section 5.4.3	Social cost of carbon of $xx.xx, 50% of PJM emissions
Economic impacts	$37,637,711	5.47%	Section 5.4.4	DEDO IMPLAN analysis using industry data (4)
Total offsets	$60,929,767	8.85%		
Net Cost (Benefit) of RPS Compliance	##########	-5.10%		

Solar PV	Cost in $	% of Retail	Regulation	Notes
Total Retail Costs of Electricity	##########		Section 4.4	
DPL SREC procurement	$ 7,465,951		Section 4.3.2	DPL Compliance Report
GEF used to support PV	$ 2,391,217		Section 4.3.1	Green Energy Fund expenditures in CY 2014/15 (2)
Solar Cost of Compliance	$ 9,857,168	1.43%	Section 4.3	
Offsets				
Market conditions	n/a	n/a	Section 5.4.1	No significantly sharp market fluctuations
Avoided costs capacity in MW	n/a	n/a	Section 5.4.2	
Avoided costs energy in MWh	n/a	n/a	Section 5.4.2	
Externalities NOx and SO2	$ 2,282,483	0.33%	Section 5.4.3	DPL 2012 IRP; 50% of PJM emissions avoided (3)
Externalities CO2	$ 1,036,301	0.15%	Section 5.4.3	
Economic impacts	$37,637,711	5.47%	Section 5.4.4	DEDO IMPLAN analysis using industry data (4)
Total offsets	$40,956,495	5.95%		
Net Cost (Benefit) of PV Compliance	##########	-4.52%		

Section 4.0 of the proposed regulation directs how the cost of compliance is calculated.
Section 5.0 of the proposed regulation identifies factors that can be considered in deciding whether a freeze should be declared.

Notes
(1) DPL buys wind as energy, capacity and RECs.
(2) $2,391,216.65 of the Green Energy Fund was granted to support solar PV in CY 2014/15.
(3) % of externalities attributed to SREC 14.25% (Assumes PV & other renewables displace PJM fuel mix emissions proportionally.)
(4) Direct and indirect effects, DEDO IMPLAN analysis using solar industry jobs data.

	$ 36.00	$ 56.00
	$ 32.19	$ 50.08
CPI 2007 to June 2015	0.8942	0.8942

Appendix 2

Office of the Registrar of Regulations,
Legislative Council,
State of Delaware

DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL

DIVISION OF ENERGY AND CLIMATE

Statutory Authority: 26 Delaware Code, Section 354(i) and (j) (26 **Del.C.** §354(i) & (j))

FINAL

Secretary's Order No.: 2015-EC-0047

104 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions

Date of Issuance: December 15, 2015
Effective Date of the Amendment: January 11, 2016

Under the authority vested in the Secretary of the Department of Natural Resources and Environmental Control ("Department" or "DNREC") pursuant to 7 **Del.C.** §§6006, 6010, the following findings of fact based on the record, reasons and conclusions are entered as an Order of the Secretary in the above-referenced regulatory proceeding.

The revised new regulation that will be adopted through this Order represents the culmination of more than three years of work that include multiple discussions with stakeholders, representatives of both private and public utilities, environmental advocacy organizations, legislators, and, of course, the public in general, along with three formal public hearings in two years. This revised new regulation is responsive to the concerns that have been raised in these discussions and through the public hearing process over the course of the last few years.

Background, Procedural History and Findings of Fact

This Order relates to the proposed revised new regulation, to wit: *Regulations Governing the Implementation of the Renewable Energy Portfolio Standards Cost Cap Provisions*, pursuant to 26 **Del.C.** §354(i) & (j) - 7 **DE Admin. Code** 104. The Department's Division of Energy and Climate commenced the regulatory development process with Start Action Notice 2012-03 dated April 16, 2012. The Department published its initial proposed new regulation in the December 1, 2013 Delaware *Register of Regulations*.

After numerous public workshops, stakeholder meetings, discussions and reviews, the Department placed legal notices in both the *News Journal* and the *Delaware State News* advertising that a public hearing would be held on January 8, 2014, to provide an opportunity for the public to comment on the proposed new regulation. Members of the public attended that public hearing, and many provided comment to the Department regarding the same, both at the time of the hearing and during the post-hearing time period. The public comment period closed following the first hearing on January 24, 2014.

Subsequent to the record closing for comment after this initial public hearing in January of 2014, the Department's Division of Energy and Climate then began a thorough review of the record that had been generated to date with respect to this proposed promulgation, including, but not limited to, a detailed review of the formal hearing transcript, and all comment received from both the regulated community and the public at large. As a result of that review, and as a result of some of the comment received, revisions were made to the initial proposed regulation at that time, as the Department believed that numerous suggestions were meritorious and should be incorporated into the proposed regulation being developed in this matter.

At that same time, it was determined that the revisions made by the Department to this proposed new regulation were substantive enough to necessitate further vetting to both the regulated community and the public at large. Thus, after formal legal notice in both the *Delaware State News* and *The News Journal* was effected by the Department, and re-publication of this revised proposed new regulation in the *Register of Regulations* was made on December 1, 2014, a second public hearing was held once again at the Public Service Commission Conference Room Auditorium, 861 Silver Lake Blvd., Dover, Delaware on January 7, 2015.

As was the case at the first public hearing, members of the public attended the hearing on January 7, 2015, and many provided comment on the proposed revised new regulation, both at the time of the hearing and during the post-hearing time period. Given the amount of feedback the Department received subsequent to this second hearing, the Department issued a press release on January 20, 2015, announcing that the time period for public comment would be extended in this matter, in order to allow the Department to receive additional public comment in this matter. The public comment period closed following the second hearing on February 16, 2015.

Following the close of the public comment period subsequent to the second public hearing, the Department once again began its review of the voluminous amount of comment received to date in this matter. Again, many meritorious comments were taken into consideration, and, accordingly, substantive changes were made to the previously revised regulation, such that a third public hearing was deemed necessary. Thus, after once again effecting formal legal notice in both the *Delaware State News* and *The News Journal*, and re-submitting this revised proposed new regulation in the *Register of Regulations*

for re-publication on November 1, 2015, a third public hearing was held at the Public Service Commission Conference Room Auditorium, 861 Silver Lake Blvd., Dover, Delaware on November 23, 2015. A few members of the public attended this third hearing, and once again comment was received by the Department regarding this proposed regulation, both at the hearing and during the post-hearing phase of this matter.

Subsequent to the third (and final) public hearing on November 23, 2015, the hearing record closed for public comment at close of business on December 8, 2015. At that time, the Department thoroughly reviewed that hearing's transcript, along with all additional comments received, and then prepared its formal Technical Response Memorandum ("TRM"), dated December 14, 2015, which documents the exhaustive review performed by the Department with regard to this proposed regulatory promulgation, and offers the Department's response to all comments received throughout this long regulatory process.

The Department has the statutory basis and legal authority, pursuant to 29 **Del.C.** §8003(7), to issue rules and regulations deemed necessary by the Secretary. Specifically, this rulemaking is in reference to the statutory authority specifically granted to DNREC's Division of Energy & Climate under 26 **Del.C.** §354(i) & (j). It should also be noted that all proper notification and noticing requirements concerning this matter were met by the Department. Proper notice of the hearing was provided as required by law.

Subsequent to receiving the Division of Energy and Climate's aforementioned TRM, The Department's presiding hearing officer, Lisa A. Vest, then prepared a Hearing Officer's Report dated December 15, 2015 ("Report"). The Report documents the proper completion of the required regulatory development process, establishes the record, and recommends the adoption of the proposed revised new regulation as attached to the Report as Appendix "B".

Reasons and Conclusions

Based on the record developed by the Department's experts and established by the Hearing Officer's Report, I find that the proposed revised new regulation, to wit: 7 **DE Admin. Code** 104: *Regulations Governing the Implementation of the Renewable Energy Portfolio Standards Cost Cap Provisions*, pursuant to 26 **Del.C.** §354(i) & (j), is well-supported. Therefore, the recommendations of the Hearing Officer are hereby adopted, and I direct that the proposed regulatory revised new regulation be promulgated as final.

I find that the Department's experts in the Division of Energy and Climate fully developed the record to support adoption of this revised new regulation. The adoption of this revised new regulation will allow Delaware to adopt rules to govern how the Department's Director of the Division of Energy and Climate administer their obligations under 26 **Del.C.** §354(i) & (j). It should be noted that the statute directs when and whether said Director may institute a freeze on the implementation of Delaware's Renewable Energy Portfolio Standards, as provided for in 26 **Del.C.** §354.

In conclusion, the following reasons and conclusions are entered:

1. The Department has the statutory basis and legal authority to act with regard to the proposed revised new regulation, pursuant to 29 **Del.C.** §8003(7), to wit: to issue rules and regulations deemed necessary by the Secretary. Specifically, this rulemaking references the statutory authority specifically granted to DNREC's Division of Energy & Climate, pursuant to 26 **Del.C.** §354(i) & (j);

2. The Department has jurisdiction under its statutory authority, pursuant to 7 **Del.C.** Ch. 60, to issue an Order adopting this proposed revised new regulation as final;

3. The Department provided adequate public notice of the initial proposed new regulation and all proceedings in a manner required by the law and regulations, provided the public with an adequate opportunity to comment on said new regulation, including at the times of each public hearing and all post-hearing phases of this promulgation as referenced in detail above, consistent with 29 **Del.C.** §10118(a), in order to consider all public comment on the same before making any final decision;

4. Due to substantive changes made to the proposed regulatory language during the course of this rulemaking process, the Department caused the revised proposed new regulation to be re-published in the State of Delaware *Register of Regulations* on December 1, 2014, and then again with additional revisions on November 1, 2015, provided the public with an ample amount of days to comment on the same as referenced above, and held the record open most recently through close of business on December 1, 2015, in order to consider all public comment on these proposed revised regulatory amendments before making any final decision;

5. While the Department made recent additional changes to the proposed regulatory language, as set forth in the above-referenced TRM of December 14, 2015, such changes do not alter the meaning or function of the proposed new regulation, and therefore no additional re-publication or noticing of this proposed regulation is necessitated at this time;

6. The Department's Hearing Officer's Report, including its established record and the recommended proposed revised new regulation, as set forth in its Appendix "B", are hereby adopted to provide additional reasons and findings for this Order;

7. Promulgation of the proposed revised new regulation to the proposed 7 **DE Admin. Code** 104: Regulations Governing the Implementation of the Renewable Energy Portfolio Standards Cost Cap Provisions, pursuant to 26 **Del.C.** §354(i) & (j), will allow Delaware to adopt rules to govern how the Department's Director of the Division of Energy and Climate administer their obligations under 26 **Del.C.** §354(i) & (j). It should be noted that the statute directs when and

whether said Director may institute a freeze on the implementation of Delaware's Renewable Energy Portfolio Standards, as provided for in 26 **Del.C.** §354(a);

8. The Department has reviewed this proposed revised new regulation in the light of the Regulatory Flexibility Act, consistent with 29 **Del.C.** Ch. 104 (version applicable to all regulations initially published on or before December 31, 2015), and believes the same to be lawful, feasible and desirable, and that the recommendations as proposed should be applicable to all Delaware citizens equally;

9. The Department's proposed revised new regulation, as re-published in the November 1, 2015 Delaware *Register of Regulations*, and as revised and set forth in Appendix "B" of the aforementioned Hearing Officer's Report, is adequately supported, is not arbitrary or capricious, and is consistent with the applicable laws and regulations. Consequently, it is approved as a final revised new regulation, which shall go into effect ten days after its publication in the next available issue of the Delaware *Register of Regulations*; and

10. The Department shall submit this Order approving as final the proposed revised new regulation as a final new regulation, to wit: 7 **DE Admin. Code** 104: *Regulations Governing the Implementation of the Renewable Energy Portfolio Standards Cost Cap Provisions*, pursuant to 26 **Del.C.** §354(i) & (j), to the Delaware *Register of Regulations* for publication in its next available issue, and provide such other notice as the law and regulation require and the Department determines is appropriate.

David S. Small
Secretary

104 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions

1.0 Purpose

These rules govern how the Director of the Division of Energy & Climate (Director) and the Division of Energy & Climate (Division) administer their obligations under 26 **Del.C.** §354(i) & (j). The statute directs when and whether the Director may institute a freeze on the implementation of the Renewable Energy Portfolio Standards as provided for in 26 **Del.C.** §354(a).

2.0 Definitions

For purposes of this regulation, the following words and phrases shall have the following meaning unless the context clearly indicates otherwise:

"**Alternative compliance payment**" means a payment of a certain dollar amount per megawatt hour, which a Commission-Regulated Electric Company may submit in lieu of supplying the minimum percentage of RECs from Eligible Energy Resources required as defined and set by 26 **Del.C.** §§352(1) and 358(d).

"**Avoided system costs**" means reductions in electric generation, transmission or distribution costs.

"**Commission-Regulated Electric Company**" means the same as an Electric Distribution Company in 26 **Del.C.** §1001(12).

"**Compliance year**" means the calendar year beginning with June 1 and ending with May 31 of the following year, for which a Commission-Regulated Electric Company must demonstrate that it has met the requirements of the subchapter known as the "Renewable Energy Portfolio Standards Act".

"**Director**" means the Director of the Division of Energy & Climate, who is considered the State Energy Coordinator for the purpose of these rules.

"**Division**" means the Division of Energy & Climate, the successor agency to the Delaware Energy Office.

"**End-use customer**" means a person or entity in Delaware that purchases electrical energy at retail prices from regulated electric utilities.

"**Exempt sales**" means the retail customer sales of a Commission-Regulated Electric Company that is not included in the total retail sales for RPS compliance.

"**Externality benefits**" means reductions in environmental, health and mortality costs **[and improvements in habitat]** resulting from reduced emissions.

"**Freeze**" means suspension of enforcement or implementation of the annual increase in the RPS as provided for under 26 **Del.C.** §§352(3) & 354(a).

"**Green Energy Fund**" means the grant program authorized under 29 **Del.C.** §8057.

"**Integrated Resource Plan**" or "**IRP**" means the plan filed by the Commission-Regulated Electric Company to meet the requirements of 26 **Del.C.** §1007(c) & (d).

"**Non-exempt sales**" means the retail customer sales of a Commission-Regulated Electric Company that is included in the total retail sales for RPS compliance.

"**PJM**" or "**PJM interconnection**" means the regional transmission organization that coordinates the movement of wholesale electricity in the PJM region, or its successors at law.

"**Price suppression effects**" means reductions in energy or capacity costs due to competitive pressures from renewable resources.

"**PSC**" means the Delaware Public Service Commission.

"**REC costs of compliance**" means the total costs expended by the Commission-Regulated Electric Company to achieve the applicable RPS percentage standards for RECs during a respective compliance year.

"**REC percentage requirements**" and "**SREC percentage requirements**" mean the renewable energy portfolio requirements for each compliance year as set forth in 26 **Del.C.** §354(a).

"**Renewable Energy Cost of Compliance**" means the total costs expended by the Commission-Regulated Electric Company to achieve the applicable RPS percentage standards for all renewable energy during a respective compliance year.

"**Renewable Energy Credit**" or "**REC**" means a tradable instrument defined by 26 **Del.C.** §352(18) used to demonstrate compliance with the percentage requirements set forth in 26 **Del.C.** §354(a).

"**RPS**" means the renewable portfolio standard, the minimum percentage of total electricity sales delivered to Delaware end-use customers that is derived from eligible energy resources established under 26 **Del.C.**, §354.

"**Solar alternative compliance payment**" means the payment of certain dollar amounts expended in lieu of supplying the minimum percentage from solar photovoltaics as defined and set by 26 **Del.C.** §§352(24) and 358(e).

"**Solar Renewable Energy Cost of Compliance**" means the total costs expended by a Commission-Regulated Electric Company to achieve the applicable RPS percentage standards for solar photovoltaic renewable energy during a respective compliance year.

"**Solar Renewable Energy Credit**" or "**SREC**" means the tradable instrument defined by 26 **Del.C.** §352(25) used to demonstrate compliance with the percentage requirements set forth in 26 **Del.C.** §354(a).

"**Third party supplier**" means an electricity supplier that sells power to end-use customers delivered over the distribution facilities of the Commission-Regulated Electric Company. It does not include the Commission-Regulated Electric Company, Rural Electric Cooperatives or Municipal Electric Companies.

"**Total Retail Costs of Electricity**" means the total costs paid by customers of the Commission-Regulated Electric Company for the supply, transmission, distribution and delivery of retail electricity to serve non-exempt customers, including those served by third party suppliers, during a respective compliance year.

3.0 Application

3.1 These rules shall apply only to a Commission-Regulated Electric Company. These rules shall not apply to electric supply provided by either:

3.1.1 an exempted municipal electric company or a municipal utility (as set forth in 26 **Del.C.** §363); or

3.1.2 an exempted rural electric cooperative or a rural electric cooperative (as set forth in 26 **Del.C.** §363).

3.2 These rules will be applied immediately upon enactment.

4.0 Calculation of the Cost of Compliance

4.1 The Division shall calculate the Renewable Energy Cost of Compliance, the Solar Renewable Energy Cost of Compliance and the Total Retail Cost of Electricity as follows.

4.2 The Division shall calculate the Renewable Energy Cost of Compliance for a particular compliance year to be:

4.2.1 the total of contributions to that portion of the Green Energy Fund used to support the development of renewable resources, plus

4.2.2 the cost of RECs and SRECs retired to satisfy the RPS requirement, plus

4.2.3 all Alternative Compliance Payments.

4.3 The Division shall calculate the Solar Renewable Energy Cost of Compliance for a particular compliance year to be:

4.3.1 the total of contributions to that portion of the Green Energy Fund used to support the development of photovoltaic renewable resources, plus

4.3.2 the cost of SRECs retired to satisfy the RPS requirement, plus

4.3.3 all Solar Alternative Compliance Payments for the solar photovoltaic requirement.

4.4 The Division will determine the Total Retail Costs of Electricity as all customer costs for non-exempt load customers for a particular compliance year.

5.0 Determination by the Director

5.1 The Director shall review the calculations of the Division.

5.2 If the Division calculations show that the Renewable Energy Cost of Compliance is greater than 3 percent of the Total Retail Costs of Electricity for the compliance year, the Director shall, after consulting with the **[~~staff of the~~]** PSC, determine whether a freeze should be implemented.

5.3 If the Division calculations show that the Solar Renewable Energy Cost of Compliance is greater than 1 percent of the Total Retail Costs of Electricity for the compliance year, the Director shall, after consulting with the **[~~staff of the~~]** PSC, determine whether a freeze should be implemented.

5.4 In making a determination, the Director **[~~may~~ shall]** consider:

5.4.1 the overall energy market conditions;

5.4.2 the avoided cost benefits from the RPS;

5.4.3 the externality benefits due to the RPS; and

5.4.4 the economic impacts of the deployment of renewable energy in Delaware.

5.5 Overall market conditions may include shifts in energy prices, long term market trends, adjustments for short term fluctuations, changes in compliance costs, consumer benefits of other state energy policies such as the implementation of energy efficiency programs, and the overall cost of energy to consumers.

5.6 Avoided cost benefits from the RPS may include avoided system costs and price suppression effects attributable to the deployment of renewable energy that result in lower net electricity costs.

5.7 Externality benefits of changes in energy markets may include externality savings in health and mortality costs and environmental impacts due to policies promoting cleaner energy in Delaware and regional energy generation. To the extent possible, the externality savings should be consistent with the current IRP filed by the Commission-Regulated Electric Company, except where other published methods or studies are determined to be more appropriate.

5.8 Economic development benefits may include the overall economic activity attributed to jobs created by the development of renewable energy in Delaware.

[~~6.0 Implementation~~

~~If the Director determines that a freeze should be implemented under Section 5.0 above, the Director, in consultation with the staff of the PSC, will declare the freeze and notify the Commission-Regulated Electric Company that filed reports on RPS compliance. The Director will also publish notice of the freeze in the next appropriate issue of the Delaware *Register of Regulations*.~~]

[~~7.0~~ 6.0]Lifting of a Freeze

[~~7~~6].1 If a freeze has been imposed, the Division will calculate compliance costs, using the methods described in Section 4.0 of this regulation.

[~~7~~6].2 The Director will review the calculation and determine whether to lift a freeze using the methods and criteria described in Section 5.0 of this regulation.

[~~7~~6].3 If the total cost of compliance falls below the 3 percent threshold in Section 5.2 of this regulation or **[the]** 1 percent threshold in Section 5.3 of this regulation, the Director shall lift a freeze following consultation with the **[~~staff of the~~]** PSC.

[~~7~~6].4 If a freeze is lifted, the Director will promptly notify, electronically and by mail, the Commission-Regulated Electric Company that filed reports on RPS compliance. The Director will also:

[~~7~~6].4.1 provide prior notice of the lifting of the freeze to the PSC; and

[~~7~~6].4.2 publish notice of the lifting of the freeze in the next appropriate issue of the Delaware *Register of Regulations*.

[~~8.0~~ 7.0]Administration

[~~8~~7].1 Within 90 days after the end of any compliance year, the Commission-Regulated Electric Company shall submit to the Division in writing and electronically the following information for the applicable compliance year:

[~~8~~7].1.1 the Renewable Energy Cost of Compliance for that compliance year;

[~~8~~7].1.2 the Solar Renewable Energy Cost of Compliance costs for that compliance year; and

[~~8~~7].1.3 the Total Retail Costs of Electricity for that compliance year.

[~~8~~7].2 Within 30 days from receipt of the information described in Section **[~~8.1~~ 7.1]** of this regulation from the Commission-Regulated Electric Company, the Division shall calculate the cost of compliance as described in Section 4.0 of this regulation and present the results to the Director.

[~~8~~7].3 Within 30 days of receipt of the calculations of the cost of compliance from the Division, the Director will, after receipt of the calculations **[and consultation with the PSC]**, make a determination as described in Section 5.0 of this regulation and **[~~present to the Registrar for publication~~ notify the Commission-Regulated Electric Company that filed reports on RPS compliance. The Director will also publish notice of the freeze in the next appropriate issue of the Delaware *Register of Regulations*]**.

[~~8~~7].4 The public will have 15 business days from the publication of the Director's determination to offer comment. The Director may alter or amend the determination based on review of the public comments.

[~~8~~7].5 The Director shall make a final determination, including effective date, **[~~and~~]** provide public notice **[to the Registrar,]** and notify electronically and by mail the PSC, the Commission-Regulated Electric Company, and other interested parties within 15 business days of the close of public comments.

[~~9.0~~ 8.0]Existing Contracts

In implementing a freeze under these rules, existing contracts for the production or delivery of RECs, SRECs, renewable energy supply or other environmental attributes shall not be abrogated.

Appendix 3

7 Del Admin Code 104: Regulations Governing the Implementation of the Renewable Energy Portfolio Standards Cost Cap Provisions

DPL's ESTIMATED Responses for Compliance Year 2015/16

		CY 2015/16
	DPL RPS Revenues[2]	$ 30,085,165
	Transitional Retail Contract Reported RPS Costs	$ 1,119
	QFCP Revenues	$ 34,316,454
(a) the Renewable Energy Cost of Compliance for that retail supplier or electric distribution utility for that compliance year;		$ 64,402,738
	Solar RECs	$ 6,787,614
	QFCP Costs Allocation	$ -
(b) the Solar Renewable Energy Cost of Compliance for that retail supplier or electric distribution company for that compliance year;		$ 6,787,614
(c) the Total Retail Costs of Electricity for that retail supplier or electric distribution company for that compliance year.[3]		$ 682,403,734
(d) the total MWh of output (either actual or deemed) produced by a QFCP during the compliance year;		238,998 MWH
(e) the total amount of QFCP-RC payments paid by its customers during the compliance year;		$ 34,316,454
(f) the calculation of the average QFCP offset cost for the compliance year under section 7.0; and	QFCP Offset Costs	143.58 $/MWH
(g) the number of output hours that it would allocate to SREC and REC offset hours for the compliance year.	Solar	0 MWH
	Non-Solar[4]	238,998 MWH

Notes:

(1) This document contains information in addition to that needed to comply with Cost Cap Rules.

(2) The Renewable Energy Cost of Compliance includes net losses or gains from energy sales from Commission approved projects that include the purchase of renewable energy.

(3) Excludes any revenues collected by DPL from customers that are exempt from RPS requirements.

(4) Includes 12,293 MHWs of QFCP generation is being carried-over from the 2014/15 compliance year and excludes 277 MWH of being carried-over to the 2016/17 compliance year.

Appendix 4

Costs and Benefits of the RPS under 26 Del. C. § 354(i) & (j)
Report for Compliance Year (CY) 2015/16
DRAFT - FOR DISCUSSION PURPOSES ONLY
27-Oct-16

All Renewable Resources	Cost in $	% of Retail	Regulation	Notes
Total Retail Costs of Electricity	$ 682,403,734		Section 4.4	Retail costs of electricity to DPL customers in CY 2015/16 (1)
GEF to support renewable resources	$ 1,950,730		Section 4.2.1	GEF expenditures for renewable energy in CY 2015/16 (2)
DPL REC and SREC procurement	$ 30,085,165		Section 4.2.2	DPL RPS Compliance Report for CY 2015/16
Renewable Energy Cost of Compliance	$ 32,035,895	4.69%		
Offsets				
Market conditions	n/a	n/a	Section 5.4.1	No significantly sharp market fluctuations
Avoided costs capacity in MW	n/a	n/a	Section 5.4.2	Price suppression effects not calculated for CY 2015/16
Avoided costs energy in MWh	n/a	n/a	Section 5.4.2	Price suppression effects not calculated for CY 2015/16
Externalities NOx and SO2	$ 14,670,119	2.15%	Section 5.4.3	DPL 2014 IRP; 50% of PJM emissions avoided (3)
Externalities CO2	$ 5,413,175	0.79%	Section 5.4.3	Social cost of carbon of $32.75, 50% of PJM emissions (4)
Economic impacts	$ 12,040,396	1.76%	Section 5.4.4	Salaries of jobs lost to RPS freeze, IMPLAN multiplier of 1.71 (5)
Total offsets	$ 32,123,690	4.71%		
Net Cost (Benefit) of RPS Compliance	$ (87,795)	-0.01%		

Solar PV	Cost in $	% of Retail	Regulation	Notes
Total Retail Costs of Electricity	$ 682,403,734		Section 4.4	
GEF used to support PV	$ 1,950,730		Section 4.3.1	Green Energy Fund expenditures in CY 2015/16 (2)
DPL SREC procurement	$ 6,787,614		Section 4.3.2	DPL RPS Compliance Report for CY 2015/16
Solar Cost of Compliance	$ 8,738,344	1.28%	Section 4.3	
Offsets				
Market conditions	n/a	n/a	Section 5.4.1	No significantly sharp market fluctuations
Avoided costs capacity in MW	n/a	n/a	Section 5.4.2	Price suppression effects not calculated for CY 2015/16
Avoided costs energy in MWh	n/a	n/a	Section 5.4.2	Price suppression effects not calculated for CY 2015/16
Externalities NOx and SO2	$ 2,349,134	0.34%	Section 5.4.3	DPL 2014 IRP; 50% of PJM emissions avoided (3)
Externalities CO2	$ 866,815	0.13%	Section 5.4.3	Social cost of carbon of $32.75, 50% of PJM emissions (4)
Economic impacts	$ 12,040,396	1.76%	Section 5.4.4	Salaries of jobs lost to RPS freeze, IMPLAN multiplier of 1.58 (5)
Total offsets	$ 15,256,344	2.24%		
Net Cost (Benefit) of PV Compliance	$ (6,518,000)	-0.96%		

Section 4.0 of the proposed regulation directs how the cost of compliance is calculated.
Section 5.0 of the proposed regulation identifies benefits to be be considered in deciding whether a freeze should be declared.

Notes

(1) DPL report on RPS costs for CY 2015/16
(2) $1,950,730.12 of the Green Energy Fund was granted to support solar PV in CY 2015/16
(3) % of externalities attributed to SRECs: 16.01% (Assumes PV & other renewables displace PJM fuel mix emissions proportionally)
(4) EPA social cost of CO2 of $38/metric ton, 3.0% discount rate on future costs, 2007 dollars adjusted for 2016
CPI 2007 to June 2016 0.8618 $ 32.75
(5) Direct, indirect and induced effects, DEDO IMPLAN analysis using solar industry jobs data
Multiplier from previous analysis = 1.58

Appendix 5

NREL

Delaware Solar PV LMP and Capacity Cap Analysis

Web

John Nangle, Kim Peterson & Blaise Stoltenberg

November 2014

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Delaware Solar Analysis

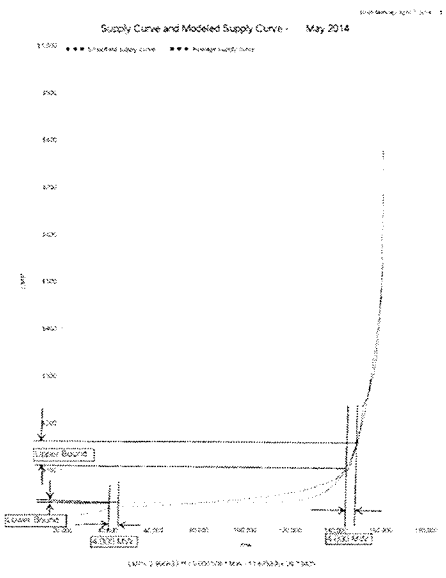
- **2 Main Questions to Address:**
  - What is the economic benefit of currently installed Delaware PV systems(~60 MW) in Delaware (PJM territory)?
  - How much PV can be installed before the 1% cost cap is reached?

Delaware Solar Analysis

- **Methodology to determine DE PV economic benefit: Local Marginal Pricing (LMP):**
  - Use PJM LMP cost curves
  - Determine PJM LMP difference (energy cost) with and without DE solar production (not exact calculation, therefore:)
    - Determine LOWER BOUND through LMP as a function of PJM Energy demand (MW reported demand with and with out DE solar production)
    - Determine UPPER BOUND through LMP as a function of reported actual PJM hourly energy price ("virtual" PJM energy demand with and without DE solar production)

Delaware Solar Analysis

- **PJM LMP Cost Curves**
  - LOWER BOUND: LMP cost difference based on demand (with and without DE solar production)
  - UPPER BOUND: LMP cost difference based on energy price ("virtual" PJM energy demand with and without DE solar production)



Delaware Solar Analysis

- **Methodology:**
  - DE Hourly PV Production:
    - System Advisor Model (SAM) using PV Watts Model
    - Hourly irradiance and weather data for analysis period
    - 8 representative DE locations
    - Output: average AC (MW) production per installed DC (MW)
  - PJM LMP difference (energy cost) with and without DE solar production:
    - Lower Bound: LMP difference for calculated DE PV production at reported PJM Energy Demand (MW)
    - Upper Bound: LMP difference for calculated DE PV production at calculated PJM "virtual" Energy Demand based on PJM reported energy price
  - Total DE PV economic benefit: Energy Cost Difference (PJM) (LMP [$/MW] * Energy Demand [MW]) with and without DE solar—Hourly and Summed over year

Delaware Solar Analysis

- **Result: What is the economic benefit of installed PV systems in DE (~48 to 60 MW)? (For all PJM territory during 1-year analysis period)**
  - Lower Bound: $2,749,426 cost savings
  - Upper Bound: $22,664,699 cost savings

Delaware Solar Analysis

- **Data and Sources (June 2013- May 2014):**
  - Local Marginal Price Curves (All of PJM—fitted curves to actual data [$/MW as function of MW demand])
  - Hourly Energy Demand--MW (All of PJM—56 GW to 153 GW)
  - Hourly Energy Price--$/MW (All PJM--$0 to $1,839)
  - PV Installed Capacity in DE –MWdc (updated daily)
  - Hourly Solar Irradiance (DNI, GHI,& DHI), ambient temperature & wind speed (8 DE locations—Solar Anywhere)
  - Wilmington, DE TMY3 used as base weather file

Delaware Solar Analysis

- **Question 2: What is estimated cost cap for PV incentives and how much PV can be supported under this cap?**
  - 2 components to PV cost in Delmarva Territory:
    - Annual cost of Solar Renewable Energy Certificates (SRECs)
    - Green Energy Program Annual Incentives to PV systems

- **Note: Cost cap is still under rule making but is presently defined as 1% of subject Delmarva Retail sales.**

Delaware Solar Analysis

- **Annual cost of Solar Renewable Energy Certificates (SRECs)?**
  - 2012 through 2014 Reported SRECs and Estimated Average Price
    - 2012: 13,127 MWh @ $172/MWh = $2.26M
    - 2013: 9,992 MWh @ $ 46/MWh = $460K
    - 2014: 10,222 MWh @ $ 74/MWh = $757K
  - Total: 33,342 MWh @ $104/MWh = $3.74M/year

- **Assumptions: Above contracts are for minimum of 7 years, are continued annual expense and are subject to 1% cost cap.**
- **Note: SREC information from: http://www.srecdelaware.com/**

Delaware Solar Analysis

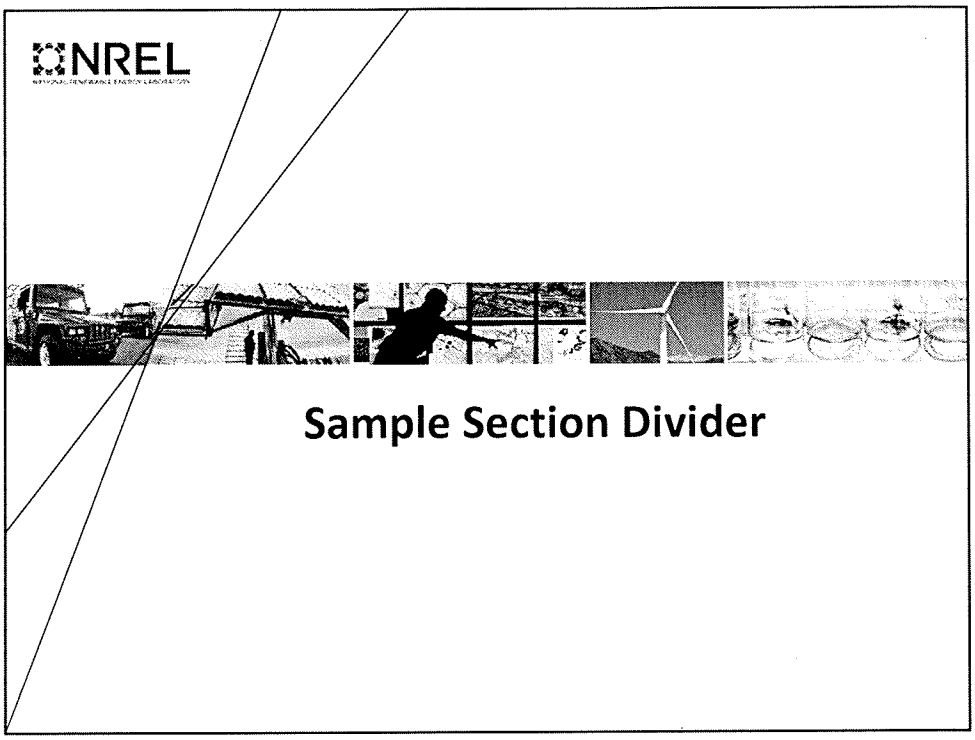
- **Annual cost of Green Energy Program (GEP)?**
  - Stated Budget of $1.87M/year (PV, Solar Thermal, Wind and Geothermal Heat Pumps)
  - Inputs sheet has estimated $/W GEP incentive input for scenario building.
  - Example: $0.10/W and increase in PV of 10.8 MW during analysis period: GEP PV cost would be $1.079 M/year

Delaware Solar Analysis

- **Annual cost of PV (SRECs + GEP) and Cost Cap?**
  - Example based on estimates
    - SRECs = $3.74 M/year
    - GEP = $1.079 M/year
    - Total Public PV Cost = $4.55 M/year
- **Estimated Cost Cap**
  - 8.3 MWh/year * $111/MWh * 1% = $9.2 M/year

Delaware Solar Analysis

- **What is estimated maximum PV under Cost Cap?**
  - Eventually all SREC cost
    - SRECs eventually all $50/MWh
    - $9.2 M/year Cost Cap => 184,000 MWh of SRECs
  - Estimated PV Install (MWDC) to produce 184,000 MWh = 146 MW


NREL
Sample Section Divider

Appendix 6

G. Estimated Impact of Renewables on Air Quality

The wind and solar resources that are part of Delmarva Power's renewable portfolio are considered "intermittent" resources. In other words, they supply energy into the electrical grid whenever the wind is blowing and the sun is shining. In terms of PJM generation dispatch, whenever wind and solar resources are producing power, their output is taken into the grid. In general, when wind and solar resources are supplied into the grid, this requires other generation resources that are "dispatchable" to reduce their generation output in order to maintain grid balance and stability. All dispatchable resources, other than nuclear facilities, produce air emissions such as carbon dioxide (CO_2), Sulfur dioxide (SO_2), and Nitrous Oxide (NO_X) at varying rates. Accordingly, when wind and solar resources generate power, other sources reduce their output and related air emissions.

It is difficult to determine with any precision how much CO_2, SO_2, and NO_X are displaced by wind and solar resources because marginal changes in PJM generation emissions are different for each and every hour during the year, and the specific hourly production of intermittent wind and solar resources during a year's time is hard to predict. Consequently, calculating the exact emissions avoided by intermittent resources can be a complex undertaking. Nevertheless, using some simplifying assumptions, average PJM emission rates for CO_2, SO_2, and NO_X can be combined with the expected annual renewable resource generation mWh associated with Delmarva's renewable resource portfolio to obtain *a range* of benefits from the reduction of generation air emission that may be attributable to Delmarva Power's RPS compliance. Based on the implied values of a ton of SO_2, NO_x and CO_2 from the 2012 IRP, evaluation of changes in air quality over 2013 to 2022, the range of emission reductions can then be valued in dollar terms to determine the potential avoided health costs.

The Air Quality analyses presented in Section IX and Appendix 8 of the 2012 IRP estimates the potential range of health benefits from air quality improvement between 2013 and 2022 from all sectors including electric power generation, industry, and transportation. Based on the contribution of electric power generation emissions from the Mid-Atlantic Region, monetized health-related costs in these states is estimated to range from $36 to $98 billion (U.S. $2010) for 2022. The range is based on different epidemiological studies and discount rates (the discount rates account for the time lag between changes in PM2.5 concentration and changes in PM2.5 mortality).

Breaking this down by type of emission and based on the PPTM results, it is estimated that 63% of the overall health cost is attributable to SO_2 emissions, 6% of the overall cost is attributable to NO_x emissions, and 29% of the overall cost is attributable to primary PM2.5 emissions. As reported in the 2012 IRP, the cost per ton for SO_2 and NO_x is estimated to be within the range of $43,000 – $110,000 for SO_2, and $9,500 – $25,000 for NO_x. Also, as

discussed in Appendix 8 of the 2012 IRP, the health cost per ton of CO_2 is estimated to be within the range of $1 to $100 per ton.

Average annual emission rates (tons/mWh) for CO_2, NO_x and SO_2 can be calculated from the Reference Case for PJM resources that create these emissions. This is shown in Table 11 below.

Table 11
PJM Average Emission Rates (ton/mWh)

Compliance Year	CO_2	NO_X	SO_2
2015/2016	0.7718	0.00041	0.00095
2016/2017	0.7396	0.00038	0.00084
2017/2018	0.7193	0.00036	0.00078
2018/2019	0.7226	0.00037	0.00078
2019/2020	0.7445	0.00039	0.00084
2020/2021	0.7668	0.00042	0.00089
2021/2022	0.7606	0.00041	0.00087
2022/2023	0.7535	0.00040	0.00084
2023/2024	0.7422	0.00039	0.00079
2024/2025	0.7354	0.00039	0.00077

The total amount of renewable resource generation mWh enabled by Delmarva Power's renewable portfolio for the period 2013 - 2023 is shown in Table 12 below.

Table 12
Delmarva Power Renewable Resource Portfolio
Total Renewable Generation mWh

Compliance Year	Contracted Resources	Bloom	Spot	Total
2015/2016	389,003	228,636	39,358	656,997
2016/2017	395,900	228,636	134,830	759,366
2017/2018	390,689	228,636	234,312	853,636
2018/2019	390,428	228,636	324,012	943,076
2019/2020	390,169	228,636	412,879	1,031,685
2020/2021	389,912	228,636	468,557	1,087,104
2021/2022	389,655	228,636	525,742	1,144,033
2022/2023	389,400	228,636	583,471	1,201,507
2023/2024	389,146	228,636	639,480	1,257,262
2024/2025	388,894	228,636	697,413	1,314,943

As discussed earlier, when these resources produce power, they displace other resources that would have otherwise created air emissions. Also, although the exact amount of displaced air emissions is difficult to estimate, such estimates can be made using

the average emission rates shown in Table 11 above, using some simplifying assumptions. Assuming that the resources in Delmarva Power's renewable portfolio incrementally reduce air emissions at, say, either 50% or 25% of the average PJM emission rate on an annual basis, the following tables show the reduction in air emissions that would otherwise have occurred.

Table 13

Tons of Emissions Avoided by DPL Renewable Portfolio Resources
(assumes 50% of PJM average emission rates avoided)

Compliance Year	CO_2	NO_X	SO_2
2015/2016	165,300	134	312
2016/2017	196,259	143	318
2017/2018	224,789	154	334
2018/2019	258,113	173	369
2019/2020	298,951	201	431
2020/2021	329,130	227	486
2021/2022	348,115	236	499
2022/2023	366,544	243	502
2023/2024	381,727	248	496
2024/2025	399,445	254	503

Table 14

Tons of Emissions Avoided by DPL Renewable Portfolio Resources
(assumes 25% of PJM average emission rates avoided)

Compliance Year	CO_2	NO_X	SO_2
2015/2016	82,650	67	156
2016/2017	98,130	72	159
2017/2018	112,394	77	167
2018/2019	129,057	86	185
2019/2020	149,476	101	215
2020/2021	164,565	113	243
2021/2022	174,058	118	249
2022/2023	183,272	122	251
2023/2024	190,864	124	248
2024/2025	199,723	127	252

These tons of emission reductions can be applied to the dollar value per ton discussed above to provide a range of estimates for the avoided emission costs attributable to Delmarva Power's RPS compliance plan. This is shown in Tables 15 and 16 below which assume that the avoided emissions are valued at the low end of the range for avoided emission costs.

Table 15

Estimated Benefits of Reduced Air Emissions from Delmarva Power's Renewable Compliance
(50% of average PJM emission rate avoided)

Compliance Year	CO_2	NO_X	SO_2	Total
2015/2016	$165,300	$1,271,936	$13,398,183	$14,835,420
2016/2017	$196,259	$1,359,409	$13,660,158	$15,215,827
2017/2018	$224,789	$1,465,225	$14,376,148	$16,066,162
2018/2019	$258,113	$1,642,321	$15,885,089	$17,785,523
2019/2020	$298,951	$1,914,166	$18,526,143	$20,739,260
2020/2021	$329,130	$2,154,771	$20,890,496	$23,374,397
2021/2022	$348,115	$2,237,308	$21,436,236	$24,021,659
2022/2023	$366,544	$2,309,920	$21,577,441	$24,253,905
2023/2024	$381,727	$2,355,211	$21,341,700	$24,078,639
2024/2025	$399,445	$2,409,152	$21,636,446	$24,445,043

Table 16

Estimated Benefits of Reduced Air Emissions from Delmarva Power's Renewable Compliance
(25% of average PJM emission rate avoided)

Compliance Year	CO_2	NO_X	SO_2	Total
2015/2016	$82,650	$635,968	$6,699,092	$7,417,710
2016/2017	$98,130	$679,705	$6,830,079	$7,607,913
2017/2018	$112,394	$732,612	$7,188,074	$8,033,081
2018/2019	$129,057	$821,160	$7,942,545	$8,892,762
2019/2020	$149,476	$957,083	$9,263,071	$10,369,630
2020/2021	$164,565	$1,077,386	$10,445,248	$11,687,199
2021/2022	$174,058	$1,118,654	$10,718,118	$12,010,829
2022/2023	$183,272	$1,154,960	$10,788,720	$12,126,953
2023/2024	$190,864	$1,177,606	$10,670,850	$12,039,319
2024/2025	$199,723	$1,204,576	$10,818,223	$12,222,521

Section IX: Delmarva Power 2014 IRP Reference Case

In preparing the IRP, Delmarva Power develops a "Reference Case" to represent the Company's expected view of the future procurement planning environment for the –IRP Planning Period. The IRP Reference Case provides a structure for the IRP analysis and evaluations, and a point of comparison for varying key assumptions supporting the Reference Case.

The 2014 IRP Reference Case provides a dynamic view of the expected 2015 – 2024 future state of the electric system within Delaware and PJM. The major assumptions underlying the Reference Case discussed in previous sections of this document reflect the current state of the overall electric system at the time the IRP modeling analysis was undertaken.

The Reference Case provided in the 2014 IRP provides a detailed look at the results of the Company's expected future energy procurement practices for the period 2015 – 2024. The key data planning assumptions underlying the view of Delmarva Power's energy future implied by the Reference Case include the following:

1. The Delmarva Power load forecast (described in Section 4 and Appendix 4);
2. Expected Energy and demand response reductions (described in Section 5);
3. PJM approved transmission system upgrades (described in Section 6);
4. The cost and operating characteristics of supply side resource options, and the expected implementation and timing of various environmental regulations affecting power generation (described in Section 7); and
5. Delmarva Power's plan to procure RECs generated by renewable energy resources in sufficient quantities to meet the annual requirements of REPSA (described in Section 8).

The remainder of this section presents detailed information for the IRP Reference Case and the sensitivity analyses for a low natural gas price scenario.

As mentioned earlier, Delmarva Power retained Siemens Industry Inc., for its Pace Global business ("Pace Global") to prepare an independent PJM market assessment to support the 2014 IRP. Covering the period from 2015 to 2025 ("Study Period"), these analyses include Pace Global's market views for energy, capacity, and environmental markets, as well as the key drivers that reflect these views. In its market analysis, Pace Global has employed

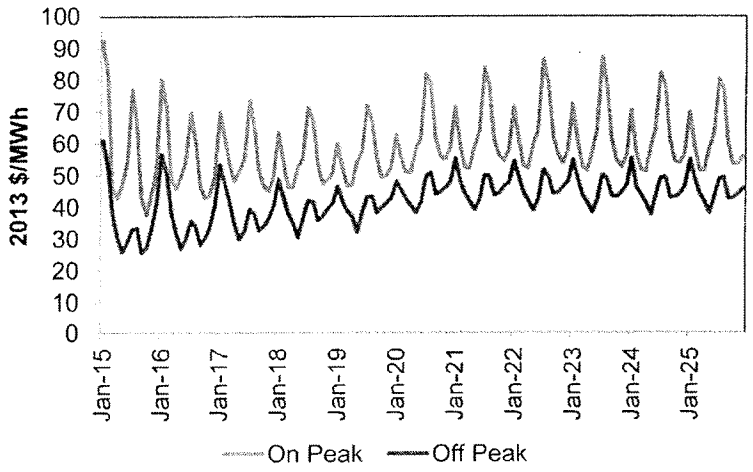
proprietary tools to simulate the deregulated power generation markets and to project market clearing prices for energy, capacity, RECs and SRECs. All monetary values in this section are denominated in 2013 U.S. Dollars (2013$) unless otherwise noted.

REFERENCE CASE MARKET PRICE PROJECTIONS

Energy Price[31]

Pace Global's reference case PJM market price projections reflect an integrated market assessment that includes inputs for natural gas prices, coal prices, load growth, environmental compliance costs, and capacity additions and retirements. Figure 1 below summarizes the Reference Case energy price projections for the DPL zone within PJM. The high price projections during winter months in the early years are driven by expectations for localized gas price spikes due to high demand and pipeline constraints. Over time, those are expected to relax, but natural gas prices at the Henry Hub and across the PJM footprint are expected to rise overall by the end of the current decade, as a result of increased demand from power generation and exports. Rising gas price expectations and coal retirements throughout PJM contribute to expected increases in power prices over time, especially during the summer peak period.

Figure 1: Reference Case PJM DPL Zone Energy Price Projections



Source: Pace Global.

[31] Appendix 6, prepared by Pace Global, provides an overview of PJM electric markets and historical prices.

Capacity Price

Figure 2 below shows Pace Global's capacity price projections for the DPL zone, which also corresponds to projections in the Eastern Mid-Atlantic Area Council ("EMAAC") Locational Deliverability Area ("LDA"), over the Study Period in $/kW-yr terms for each auction period. Capacity prices through the 2017/2018 period are based on actual PJM Base Residual Auction ("BRA") clearing prices.[32]

Capacity prices for years beyond the auction period are driven by the supply-demand balance (or reserve margin) in the region, the cost of new entry ("CONE"), and the energy revenues that can be realized by plants operating in the market. Pace Global has analyzed the PJM capacity market in an integrated fashion with our energy market projections.

Figure 2: Reference Case DPL Zone Capacity Price Projections

Source: Pace Global.

REC and SREC Price

Pace Global projects renewable energy credit ("REC") and solar renewable energy credit ("SREC") prices for Delaware and the rest of PJM through analysis of current market signals, review of the supply-demand balance for renewable generation, and incorporation of other power market fundamentals. Figure 3 below presents Pace Global's projections for both REC products in the reference case.

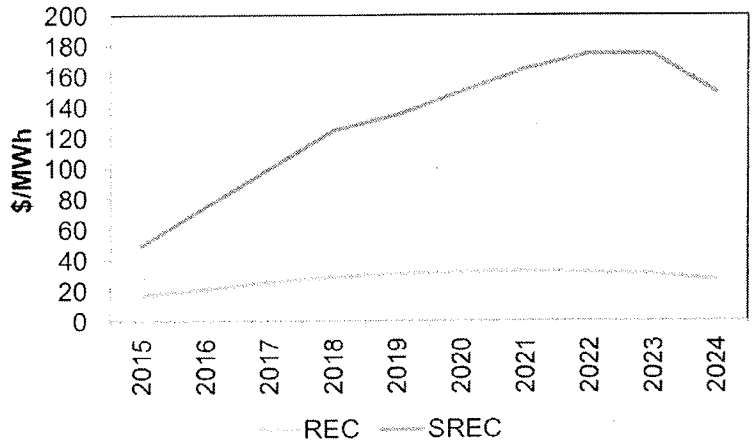
Market pricing for Delaware standard tier compliance RECs have generally trended with or close to the price levels for the collective PJM Tier I / Class I markets, including states like New Jersey and Pennsylvania. The Reported pricing for over the counter transactions

[32] The PJM BRA auction year begins June 1 and ends May 31 of the following year.

of RECs eligible for compliance in PJM state Tier I/Class I programs have risen notably in the past few years. Going forward, Pace Global sees additional upward pressure on PJM RECs as state RPS requirements continue to increase sharply through the early 2020s and beyond, and due to the uncertainty of the availability of the production tax credit (PTC).

The Delaware RPS solar carve out is adequately supplied at this time with enough solar PV installations in the State to meet current requirements, accounting for the 3 year banking provision permitted State law. The RPS requirement for solar (as with standard Tier requirements) increases significantly over the next 10 years, which will require that significant incremental capacity be built to comply. The market is expected to require additional solar installations as of the 2018-2020 time frame, which is expected to drive prices up. The recent declines in installed solar costs and efficiencies gained by the market over the past few years will help to moderate prices, however, from historic high levels seen at the onset of the Delaware solar market (over $200/mWh). Prices are expected to settle to a range between $100 and $200/mWh for Delaware SRECs until the State requirement peaks in the mid 2020's. Pace Global assumes that the 30% investment tax credit applicable to solar PV installations expires at the end of 2016 per the existing legislation.

Figure 3: Reference Case REC and SREC Projections



Source: Pace Global.

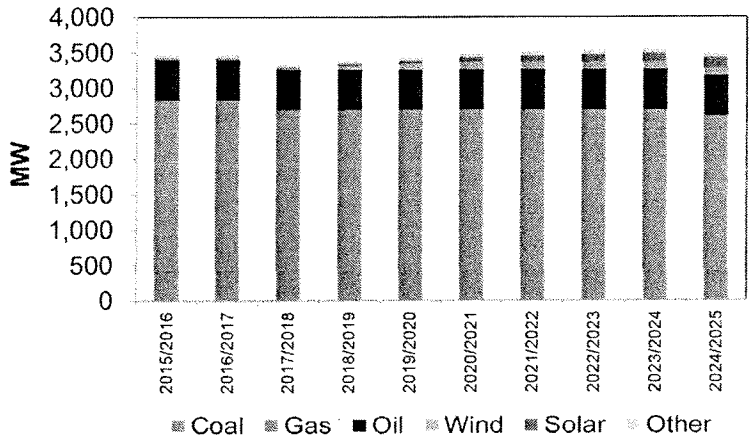
REGIONAL GENERATION, CAPACITY EXPANSION, AND EMISSIONS

Pace Global's integrated power market analysis produces projections for generation over time as well as capacity additions and retirements.

Delaware

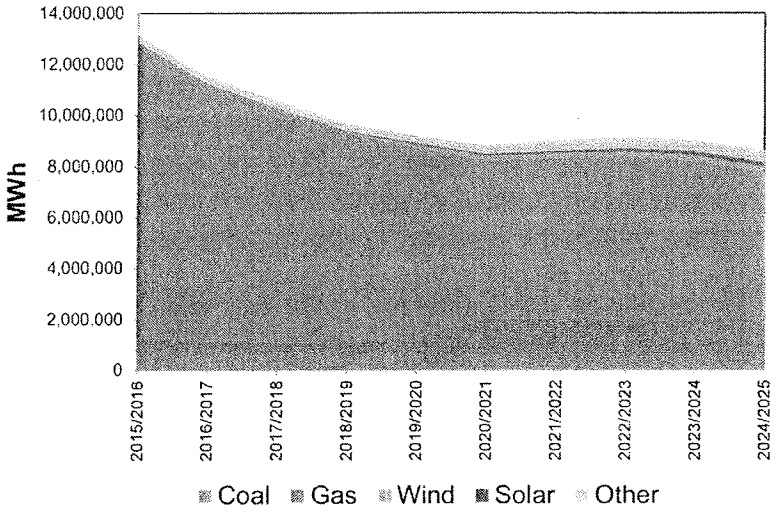
Figure 4 below presents expectations for the installed capacity in the State of Delaware over time, while Figure 5 below summarizes the projected generation by fuel type. In the 2015 time period, the Garrison combined cycle is expected to be online. Beyond that, most capacity changes are expected as a result of wind and solar additions. The generation profile within the State is dominated by natural gas. Total in-state mWh generation is expected to decline over time as a result of increased imports from new, efficient combined cycle capacity in neighboring states that displaces peaking capacity in Delaware. Pace Global's reference case also reports key emissions outputs for CO_2, NOx, and SO_2. Within Delaware, emissions of all pollutants are expected to fall significantly in the next few years. After 2020, when coal generation is projected to recover modestly, slight increases in emissions are projected. Figure 6 below summarizes the emission projections for Delaware over time.

Figure 4: Delaware Installed Capacity over Time (mW)



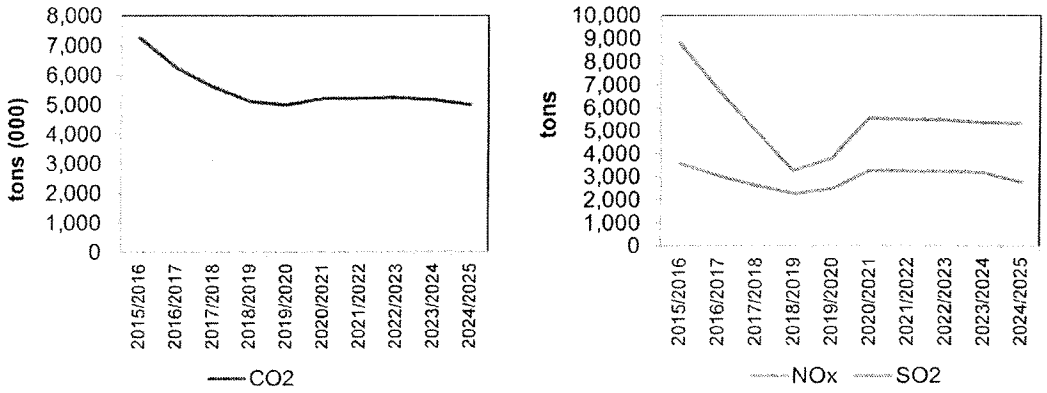
Source: Pace Global.

Figure 5: Delaware Generation by Fuel Type over Time (mWh)



Source: Pace Global.

Figure 6: Delaware Emission Projections over Time



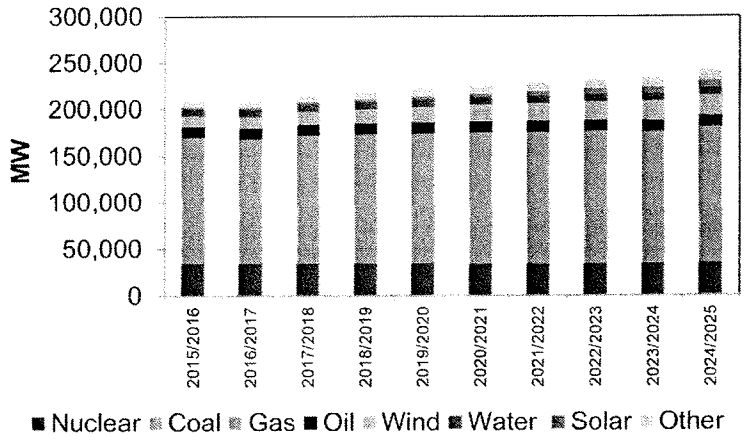
Source: Pace Global.

PJM

Figure 7 below summarizes the installed capacity projections over time for the entire PJM footprint, while Figure 8 below displays the generation by fuel type. Unlike Delaware, PJM has a large amount of nuclear capacity and generation, which is expected to stay relatively constant over time. Coal capacity is expected to decline by over 12,000 mW in the

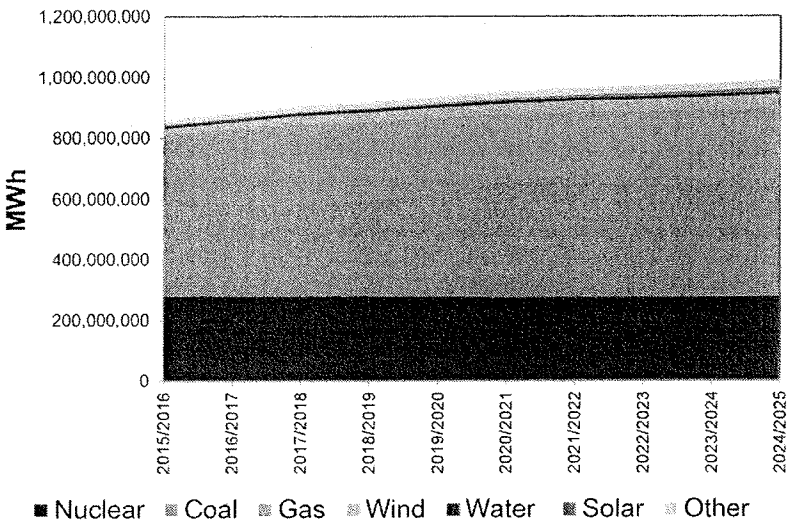
next few years due to retirements as a result of environmental regulations. Renewable and natural gas-fired capacity is expected to dominate new capacity additions through the Study Period. Although coal capacity is declining, generation is still expected to pick up by the end of the decade due to rising natural gas prices, which make coal dispatch more economic. This increase in generation in the 2020s is expected to lead to emission increases for CO_2, NOx, and SO_2. While declines are expected in the near term as a result of retirements, dispatch economics have the potential to overcome the capacity declines in the reference case over time. Figure 9 below summarizes the projected emissions across all of PJM over time.

Figure 7: PJM Delaware Installed Capacity over Time (mW)



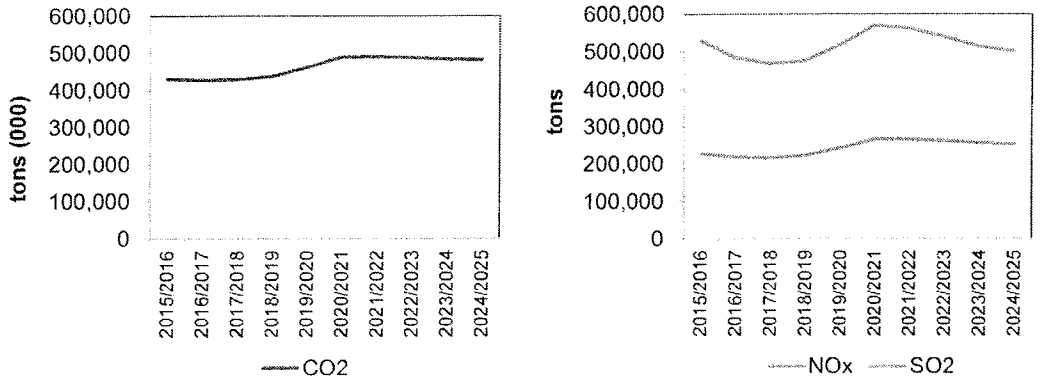
Source: Pace Global.

Figure 84: PJM Generation by Fuel Type over Time (mWh)



Source: Pace Global.

Figure 9: PJM Emission Projections over Time



Source: Pace Global.

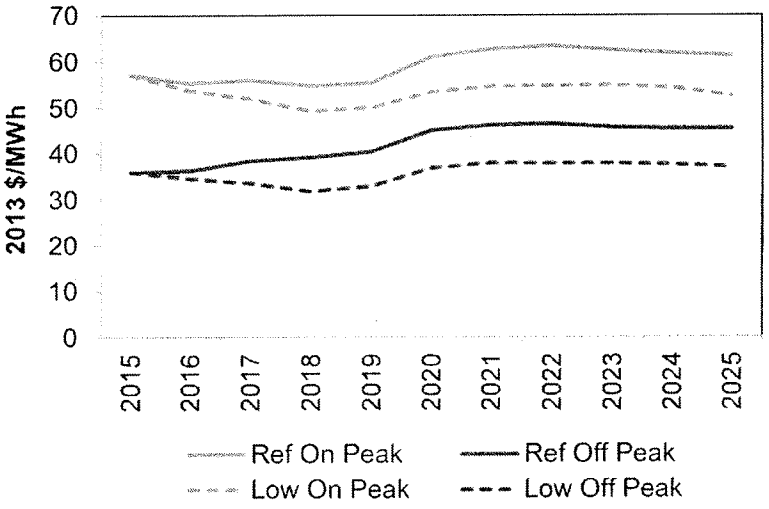
LOW NATURAL GAS CASE MARKET PRICE PROJECTIONS

Given significant uncertainty associated with the price of natural gas, Pace Global has assessed the risk of lower natural gas prices on the PJM market. This low natural gas price scenario presumes larger production capabilities in the $3-4/MMBtu (Real $) range over the next ten years. Generally speaking, the low natural gas price case has prices around $1/MMBtu lower

than those in the Reference Case. Further details on the gas price inputs can be found in the Section on fuel prices.

Figure 10 below summarizes the impacts of the low gas price scenario on projected DPL zone energy prices. As the difference between the two natural gas price projections grows, the average impact on the power prices increases as well, settling at a difference of around $8/mWh in the 2020s.

Exhibit 10: Low Natural Gas Price and Reference Case Energy Projections



Source: Pace Global.

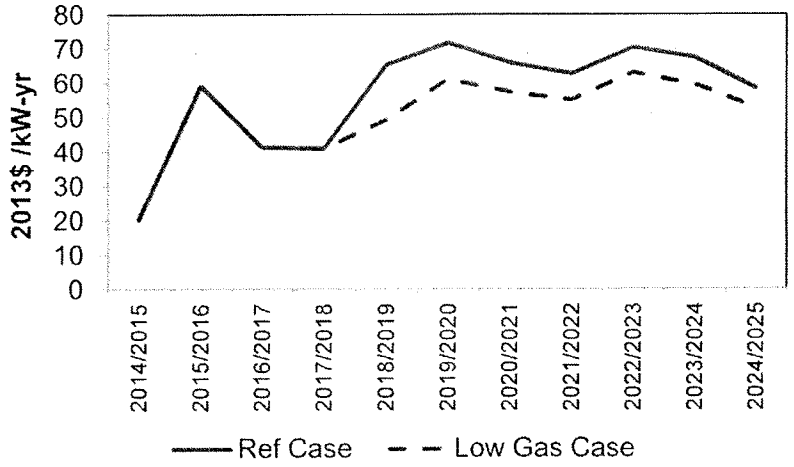
Beyond the period of cleared PJM capacity auctions, the low natural gas price case also puts downward pressure on expected capacity prices. Under the low gas price regime, new entry in the form of efficient combined cycles is expected to dispatch more, displacing coal capacity and earning higher energy margins. As a result, the capacity payment requirements for these new entrants are expected to be lower. Figure 11 below shows the difference between the capacity prices for the DPL zone across the two cases, indicating that the decline in capacity prices is projected to be about $7-8/kW-yr.

On the other hand, lower power prices are likely to lower the revenues for new renewable resources, causing the prices for RECs to increase in order to compensate new entry. Pace Global's analysis indicates that REC and SREC values are likely to increase by $4-5/mWh in this scenario. This is shown in Figure 12 below.

The low natural gas price environment is also expected to lead to lower emissions across PJM, as natural gas capacity displaces coal capacity in the generation dispatch stack. Although some price increases in natural gas are also expected in the low case around 2020, the

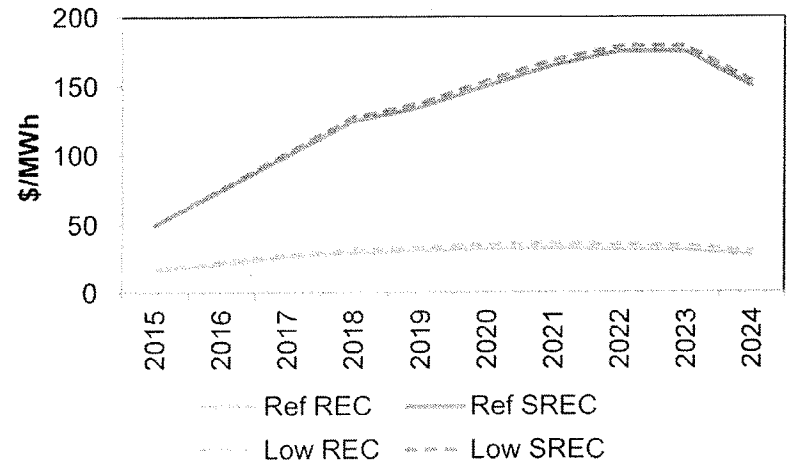
overall emissions of CO_2, NOx, and SO_2 are projected to be on the order of 20 percent lower than they are in the reference case. This is shown in Figure 13 below.

Figure 11: Low Natural Gas Price and Reference Case Capacity Price Projections



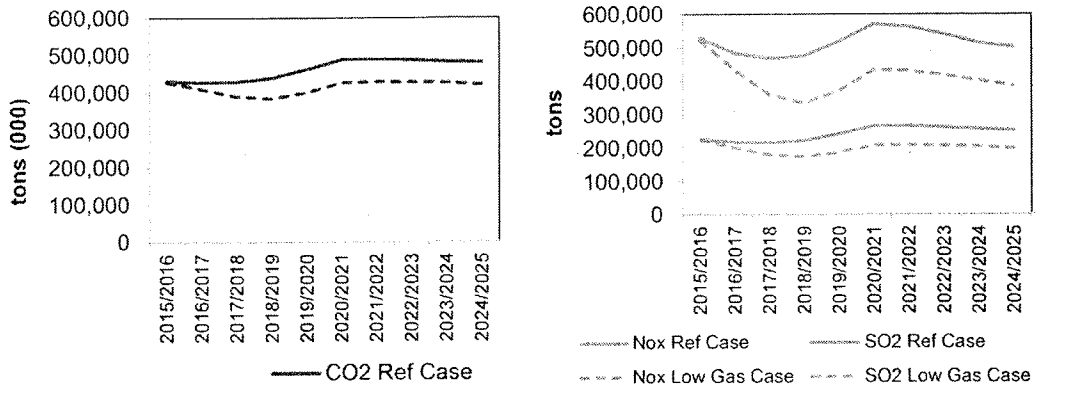
Source: Pace Global.

Figure12: Low Natural Gas Price and Reference Case REC and SREC Projections



Source: Pace Global.

Figure 13: PJM Low Natural Gas Price and Reference Case Emission Projections



Source: Pace Global.

Appendix 1

	IRP Regulation No.	Requirement	IRP Section	Comments
1	General 1.3	In accordance with 26 Del. C. 1007, DPL shall file an IRP on Dec 1, 2006 and on the anniversary date of the first filing date every other year thereafter		The 2014 IRP was filed on Monday, December 1, 2014
2	General 1.4	The IRP shall be filed in compliance with normal Commission policies and practices		The IRP was filed in accordance with all prevailing Commission rules and procedures.
3	General 1.5	The IRP shall identify the year of filing, the individuals responsible for its preparation and those individuals who shall be available to inquiries during the Commission's review of the plan.	Appendix 2	A listing of the individuals responsible for preparing the 2014 IRP and who will be available for responding to inquiries during the Commission's review of the 2014 IRP are provided in Appendix 2 of the 2014 IRP.
4	General 1.6	Confidential utility documents shall be presented under separate seal.		Confidential documents related to this IRP were presented to the Commission, Staff, DPA and DNREC under separate seal. Due to the timing of the filing of this IRP with the SOS auction process, Delmarva has filed certain pricing information as confidential so as to not bias the auction bids unfavorably. Upon completion of the auction process, this information will be deemed non-confidential by the Company and made available consistent with prevailing SOS guidelines.
5	General 1.8	The utility shall provide whatever detail and commentary necessary to demonstrate that it has met or exceeded the planning requirements as set forth in this regulation. An effort shall be made to ensure that the IRP is clearly stated and can be readily comprehended by the Commission, State Agencies , and other interested parties. The IRP shall include an Executive Summary.	Executive Summary, Appendices 4, 6, and 8	This IRP Regulation Compliance Matrix has been included as Appendix 1 to the IRP. An Executive Summary in the form required by Regulation 3.2.1. is provided in the IRP. Technical information has been set forth in the Appendices in order to keep the text of the IRP clear and straightforward.
6	General 1.9	Compliance with this regulation is a minimum standard for IRP's. The Company needs to exercise its professional judgment based on its systems or customer needs. The Company shall include all information that assists the reader to fully understand the IRP concept and the Company's IRP to meet SOS energy needs.	Executive Summary and Appendices 4,6, and 7.	Delmarva has provided an Executive Summary consistent with IRP Regulations. Most technical materials related to the IRP have been provided in Appendices. Delmarva has attempted to provide all information needed to assist the reader in understanding the IRP in a clear and starightforward manner.
7	General 1.10	This regulation requires the maintenance and retention of supply resource planning data and the reporting of IRP achievements on an annual basis starting in 2009 to the Commission, Governor and General Assembly. The Company shall retain supply resource planning data, consistent with Federal data retention guidelines and make it available for further review as necessary.		Delmarva will retain IRP information consistent with Federal data retention guidelines. Delmarva has reported on the status of the IRP to the Commission, Governor and General Assembly on an annual basis, since 2009, and will submit a new report on or before December 31, 2014.
8	General 1.11	The Company shall submit 8 copies of the IRP to the Commission, 2 copies to the Controller General's office, 2 copies to the Office of Management and Budget, 2 copies to the Division of Public Advocate and 2 copies to DNREC/Energy Office. The Commission may request up to 6 additional copies for review.		DPL submitted 8 copies of the IRP to the Commission, 2 copies to the Controller General's Office, 2 copies to the Office of Management and Budget, 2 copies to the Division of Public Advocate and 2 copies to DNREC on Monday, December 1, 2014.
9	General 1.14	The Company shall make the full IRP, including any appendices or other supporting materials, available to the general public on its web site and shall update these materials on the Company's web site to remain current with all subsequent updates, revisions or other changes made to the IRP.		A copy of the public version of the IRP will be placed on the Company's website after the IRP is filed on December 1, 2014.
10				

11	General 3.1.1	The IRP shall provide a framework for comparing a comprehensive resource mix of supply and demand-side and Transmission Service resource costs and attributes.	IRP Section 3, 5, 6, and 7.	The IRP uses a detailed and comprehensive planning model (AuroraXMP®) to evaluate the optimal combination of demand and supply side resources within PJM, including Delaware. AuroraXMP uses the most recent PJM Regional Transmission Expansion Plan (RTEP) to characterize the expected future transmission grid. Supply side resources are described in Section 7 and AuroraXMP® is described in Section 3. The RTEP is described in Section 6 and demand side resources are described in Section 5.
12	General 3.1.2	The IRP shall utilize a Resource Portfolio approach in achieving the objectives of the IRP, shall incorporate a Portfolio approach to securing resources and incorporating an analysis of risk versus certainty into the planning process, or absent such a Portfolio approach, the rationale supporting the exclusion.	Executive Summary and IRP Section 9.	The Reference Case of the IRP employs a Resource Portfolio approach to securing supply resources through the competitive Full Requirements Service (FRS) auction and a portfolio of a diverse mix of renewable resources. The IRP describes the effect on price and price stability of electricity supply prices by evaluating a low gas price forecast in comparison to the Reference Case.
13	General 3.1.3	The IRP shall provide for a regulatory, stakeholder, and public input into the development of the IRP in accordance with normal Commission policies and practices.		An IRP Working Group, composed of representatives of Delmarva, Commission Staff, DPA, DNREC, the Caesar Rodney Institute, MAREC and other interested parties met on July 23 to review and discuss key topics related to developing the 2014 IRP. These topics included the estimation of savings from energy efficiencies, Reference Case assumptions, and sensitivity analysis around natural gas prices. Public workshops on the IRP are expected to be scheduled after the 2014 IRP is filed.
14	General 3.1.4	The IRP shall include provisions for the IRP to be modified from time to time to conform with any subsequent legislative or regulatory directives.		The Commission issued Order No 8574 in July, 2014. This Order ratified the IRP filed by Delmarva in December, 2012 and provided guidance for the preparation of the 2014 IRP filing.
15	General 3.2.1	The IRP shall include an executive summary with a short description of the utility, its customers, service territory, current facilities, planning objectives, notable areas of departure in the new IRP from the old, citing specific locations within the IRP where the new aspects shall be found, load forecast, proposed IRP and Implementation Plan.	Executive Summary	An Executive Summary of the IRP with the specific information requested under this regulation is provided in the IRP.
16	General 3.2.2	The IRP shall include Established Plan Objectives in quantitative and qualitative terms by which the IRP achievements may be measured and shall not be biased against any particular option. Measures must be ascribed to each objective. The Company must include a summary of the overall process and models used in developing the IRP.	Executive Summary and Section 3	Plan objectives and measures are described in the Executive Summary of the IRP. Each objective has measures ascribed to them. The major model used in developing the 2014 IRP is AuroraXMP®. This model is used to simulate expected generation expansion and long term wholesale prices and provide information to analyse price stability and power plant air emission levels.
17	General 3.2.3	The IRP shall include a description of the load forecast, the assumptions used or implicit in creating the forecast, the range of forecasts examined and the forecast selected for the filing period and a detailed rationale for such selection.	Section 4 and Appendix 4	The load forecast is described in Section 4 of the IRP. The forecast provides "high" and "low" forecast ranges as compared to the "baseline" forecast. The load forecast documentation is described in Appendix 4.
18	General 3.2.4	The IRP shall include an Integrated Resource Evaluation which shall include a listing of all the options considered to meet the load forecast, identification of those chosen for further evaluation and possible inclusion in the IRP, and a discussion of the rationale for such selections including any key assumptions. The IRP shall include planning information which shall include a ten year planning horizon, starting with the year immediately following the planning year.	Sections 4, 5, 6 and 7.	resource options evaluated by AuroraXMP® model are discussed in Sections 3 and 7 the 2014 IRP. Key assumptions for the Reference Case are provided in Sections 4, 5, 6,and 7 of the IRP. The IRP presents information for the ten year planning period 2015-2024.
19	General 3.2.5	The IRP shall include a Scenario Analysis used to integrate the options into a single resource plan or individual scenarios for further review and analysis to include a listing of the various scenarios considered and any key assumptions.	Executive Summary	The IRP evaluates the potential impact on price and price stability through sensitivity analyses relating to an alternative natural gas price forecast.

20	General 3.2.6	The IRP shall include a description of the process used to develop the proposed IRP, including the assumptions and analysis leading up to the decision and the application of the various criteria as specified in Section 5.0.	Section 3	The process for the development of the IRP is described in Section 3 of the 2014 IRP. Discussions around the IRP process took place with the Working Group on July 23, 2014.
21	General 3.2.7	The IRP shall include an analysis of the risk and sensitivity of the proposed IRP in comparison to the other options that were considered and a contingency plan to meet the Plan Objectives should one of the supply, demand, or transmission options be either delayed or not realized.	Executive Summary	The results of various risk and sensitivity analyses around changes in natural gas prices are described in the Executive Summary.
22	General 3.2.8	The IRP shall include plans for the implementation of the IRP, for no less than 5 years, starting with the year immediately following the filing year.	Executive Summary	Implementation Plans for achieving the planning objectives of the IRP are provided in the Executive Summary.
23				
24	Load Forecast 4.1.1	The Company shall consider a range of load growth forecasts that include both historical data and future estimates.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast is based on historical data and estimates of future DSM activity. More Detailed documentation of the load forecast is provided in Appendix 4.
25	Load Forecast 4.1.2	The Company's load growth forecasts shall include both winter and summer peak demand for Delmarva Delaware load.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes both winter and summer peak demand for Delmarva Delaware Load as shown in Appendix 4.
26	Load Forecast 4.1.2	The Company's load growth forecasts shall include Delmarva Delaware SOS load by customer class.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes a breakdown by customer class.
27	Load Forecast 4.1.3	The Company's load growth forecasts shall include weather adjustments, including consideration of climate change potential.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes a severe weather case. The severe weather case represents a 90/10 scenario, where the degree days used in the equations are at the 90th percentile for both cooling and heating degree days.
28	Load Forecast 4.1.4	The Company's load growth forecasts shall include 5 year historical loads, current year end estimates and 10 year weather adjusted forecasts showing individually and aggregated Delmarva Delaware and Delmarva SOS load, and both Delmarva Delaware and Delmarva Delaware SOS load disaggregated by customer class including both capacity (MW) and energy requirements (MWh).	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes 5 year historical loads as shown in Appendix 4
29	Load Forecast 4.1.5	The Company's load growth forecasts shall include analysis of how existing and forecast Conservation, DR, DSM, Customer sited generation, various economic and demographic factors including the price of electricity will affect the consumption of electric services and how customer choice under Retail Competition may affect future loads.	Section 4 and Appendix 4	Appendix 4 provides detailed documentation of the process of how economic and demographic variables are included in the Load Forecast. Energy conservation measures and DR program impacts are subtracted from the baseline load forecast to derive the Reference Case Forecast.
30	Load Forecast 4.1.6	The Company's load growth forecasts shall include a description of the process the Company used to develop these forecasts. Forecasts should include the probability of occurrence. Within the forecasting modeling descriptions, the Company shall demonstrate how well its model predicted load for the past 5 years.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes a description of the process the Company used to develop these forecasts as shown in the DE IRP Demand Forecast Documentation provided as Appendix 4.
31				
32	Resource Portfolio Options 5.1	The Company shall include a description of the overall process and the analytical techniques it used to identify its proposed options. The Company shall not rely exclusively on any particular resource or purchase procurement policy.	Section 3	The IRP process is described in Section 3. Delmarva's Reference Case includes a mix of Full Requirements Service contracts and a diverse mix of renewable resources.
33	Resource Portfolio Options 5.2	The Company shall identify and evaluate all resource options including generation and transmission service, supply contracts, both short and long term procurement DSM, DR, and customer sited generation, even if a particular strategy is not recommended by the Company. The IRP must show an investigation of all reasonable opportunities for a more diverse supply at the lowest reasonable cost including consideration of environmental benefits and externalities. The Company shall also provide any hedging guidelines and shall identify any changes from any existing hedging policy. Cost evaluations shall contain a description of each option and an evaluation that considers the economic and environmental value of the following:	Section 3, 5, 6, 7, 8, and 9.	The IRP considers a full range of transmission, demand side, and supply resources with particular attention to renewable resources and environmental benefits.
34	Resource Portfolio Options 5.2.1	Resources that utilize New or Innovative Base load Technologies;	Section 3	The AuroraXMP® model used in the IRP considers new and innovative base load technologies within the set of resource options evaluated.

35	Resource Portfolio Options 5.2.2	Resources that provide short or long-term environmental benefits to the citizens of Delaware;		Detailed environmental analyses were filed as part of the 2010 and 2012 IRP's and are incoprporated in this IRP by Reference.
36	Resource Portfolio Options 5.2.3	Facilities that have existing fuel and transmission infrastructure;		As part of the 2010 IRP, Delmarva filed a confidential Generation Siting Study in January 2010. This Document remains relevant for the 2014 IRP.
37	Resource Portfolio Options 5.2.4	Facilities that utilize existing brownfield or industrial sites;		As part of the 2010 IRP, Delmarva filed a confidential Generation Siting Study in January 2010. This Document remains relevant for the 2014 IRP.
38	Resource Portfolio Options 5.2.5	Resources that promote Fuel Diversity,	Section 8	Delmarva mamages a portfolio of wind and solar resources.
39	Resource Portfolio Options 5.2.6	Resources or facilities that support or improve reliability; or	Section 6 and 9	The 2014 IRP shows that there are sufficient generation resources to meet the expected load forecast over the IRP planning horizon.
40	Resource Portfolio Options 5.2.7	Resources that support or improve price stability.	Executive Summary	The IRP contains an evaluation of a effects on price and price stability of changing gas prices.
41	Resource Portfolio Options 5.3	Where Transmission Service is identified as a planning option, DPL shall describe the transmission enhancement, the location, and provide PJM's assessment of the impact of the proposed transmission asset when available. The IRP shall reflect the current projects included in PJM's Regional Transmission Plan ("RTEP"). DPL shall file with the Commission any PJM revisions or updates to the RTEP immediately upon receipt.	Executive Summary and Section 6	The IRP includes a description of the transmission investments made since the last IRP and planned transmission investments needed to maintain reliability. All approved RTEP projects are included in the AuroraXMP model.
42	Resource Portfolio Options 5.4	At least 30% of the resource mix shall be acquired through the regional Wholesale Electricity Market via a bid procurement or auction process held by DPL.	Executive Summary and Appendix 5	The discussion of price and price stability in the Executive Summary is based on portfolios with more than 30% acquired through the wholesale market.
43	Resource Portfolio Options 5.5	The Company shall include a discussion of known plans to reduce existing physical, contractual, or service related portfolio resources during the IRP planning period.		The IRP includes all planned retirements at the Indian River generation facility and environmental upgrades to Indian River Unit #4.
44	Resource Portfolio Options 5.6	The Company shall include a detailed description of its energy efficiency activities in accordance with 26 Del. C. DPL Section 1020. The Company shall first consider electricity DR and DSM strategies for meeting base load and load growth needs and cost-effective renewable energy resources before considering traditional fossil fuel-based electric supply service to meet their retail electricity supplier obligations as defined in 26 Del. C. Section 352.	Section 5	The Delaware Public Service Commission approved the implementation of a Dynamic Pricing Program and a Residential Direct Load Control Program in the Fall of 2012. A description of the Company's energy efficiency efforts is provided in Section 5 of the IRP
45	Resource Portfolio Options 5.7	The Company shall evaluate all technically feasible and cost effective DR improvements. Where non-Company evaluations of DSM and Conservation are available through the Sustainable Energy Utility ("SEU") (or other organization as requested by the Commission), the Company shall summarize the results and actions taken. The Company shall collaborate and may contract with the SEU to provide services to accomplish the SEU's DSM plans. The Company, using its independent best judgment, may recommend in the IRP any DSM program first offered to the SEU but rejected by the SEU. Where DR programs are new, the Company shall summarize the anticipated benefits with respect to load reductions and provide supporting materials to justify the new program.	Section 5	Delmarva Power continues to collaborate with the SEU. A description of on-going and past SEU activities is provided in Section V of the IRP.
46	Resource Portfolio Options 5.8	The Company shall collaborate with the SEU and appropriate State Agencies in its evaluation of Customer Sited Generation resource options. The Company may enter into a contractual relationship with the SEU or other energy service providers to implement a Customer Sited Generation resource option strategy.	Section 5	Under the Solar REC Procurement Programs approved by the Commission, Delmarva has entered into contracts to purchase Solar RECs from the SEU.
47	Resource Portfolio Options 5.9	The Company shall assess the Resource Portfolio options against the set of Plan Objectives and criteria.	Section 3, 5, 6, 8, and 9	The Reference case is evaluated against the major planning criteria and plan objectives.
48				
49	Plan Development 6.1	The Company shall conduct an Integrated Resource Evaluation in formulating its potential plans for supply and demand-side resource scenarios. The Company shall describe the mechanism or process by which the Load Forecast and options have been blended into the various IRP scenarios.	Section 3, 4, 5, and 9	TheAuroraXMP® model provides an integrated planning platform. Expected energy efficiency savings are incorporated into the Reference case load forecast.

50	Plan Development 6.1.1	In integrating its supply and demand side resource, the Company shall prepare an evaluation that takes into consideration the life expectancy of the resource, if the resource provides capacity and/or energy, any improvements to system reliability, the dispatchability of the resource, any lead time requirements, the flexibility of the resource, the Generation Attributes of the resource, the efficiency of the resource and the opportunities for customer participation. The Company shall assess the probability of securing the options according to modeling information used, including any key assumptions. The Company shall provide the estimated energy and capacity impacts for each option and the rationale behind the estimate.	Section 3 and 5.	These factors are considered in the AuroraXMP® model DSM analysis.
51	Plan Development 6.1.2	The Company shall prepare a contingency plan that shall include a discussion of how the Company might alter the proposed IRP in the future if the key planning assumptions used to develop the proposed IRP in the future turn out to be different than what was assumed in preparing the proposed IRP.	Executive Summary	The IRP provides a sensitivity analysis to show the impact of changes in natural gas prices.
52	Plan Development 6.1.3	The Company shall evaluate the cost-effectiveness of the options from the perspectives of the utility and the different classes of ratepayers based on real prices (may also provide an evaluation based upon nominal prices).	Executive Summary	The impact of changing natural gas prices on electric rates for residential and commercial class is shown in the Executive Summary.
53	Plan Development 6.1.4	The Company shall include a current evaluation, detailing and giving consideration to environmental benefits and externalities associated with the utilization of specific methods of energy production (may rely on commonly available published research and not on original research by DPL). To the extent any reliable, relevant peer reviewed published research and scientific and/or medical studies commonly available includes life cycle analyses encompassing energy extraction, transport, generation, and/or use, the Company shall include such research and studies in its evaluation.	Section 8.	The IRP includes an evaluation of the environmental benefits associated with the Reference Case based on analysis provided as part of the 2012 IRP.
54	Plan Development 6.1.4	To the extent that any reliable, relevant peer reviewed published research includes life cycle analyses encompassing energy extraction, transport, generation, and/or use is commonly available, the Company shall include such research and studies in its evaluation.		The 2014 IRP incorporates, by reference, the life-cycle impact analysis completed and filed as part of the 2010 IRP.
55	Plan Development 6.1.5	The IRP shall not include any assumptions that externalities are adequately addressed by either the fact that the IRP meets the RPS, satisfies the EERS, or that the generating units to be utilized comply with existing environmental regulations. This rule does not, however, preclude a potential conclusion that the RPS or EERS in effect at the time adequately address externalities.	Section 8	The IRP includes an evaluation of the environmental benefits associated with the Reference Case based on studies completed in prior IRPs.
56	Plan Development 6.1.6	The Company shall evaluate the financial, competitive, reliability and operational risks associated with the options recommended by the IRP and how these risks may be mitigated over the 10 year planning period. This plan shall include a discussion of the likelihood of the occurrence of such risks.	Executive Summary and Section 9	The IRP provides information on expected energy prices, customer rates, and RPS compliance costs over the planning period.
57	Plan Development 6.1.7	For the options included in the proposed plan identified in the IRP, the IRP shall include an analysis of the fuel risk associated with the proposed Resource Portfolio and how such fuel risk will be mitigated when the proposed IRP is implemented.	Executive Summary	The IRP contains a sensitivity analysis of low natural gas prices compared to the Reference Case.
58	Plan Development 6.1.8	The Company shall perform sensitivity analyses on each of the candidate plans to include variations in key assumptions and to assess the likelihood of planned outcomes. These shall include the impact of proposed or existing rules and regulations on a local, regional, or national level related to climate change.	Executive Summary and Section 9	The IRP contains a sensitivity analyses of the Reference Case related to changes in the price of natural gas. The sensitivity includes an evaluation of the changes in power plant emissions including CO_2.
59	Plan Development 6.2	The Company shall forward a copy of the IRP to DNREC and seek input into externalities, including but not limited to, health effects.		DNREC provided input into the use of externalities in their written comments in response to the 2012 IRP. Delmarva used DNREC's comments in preparing the externality analysis provided in the 2014 IRP. DP&L submitted a copy of the 2014 IRP to DNREC on Monday, December 1, 2014.
60	Plan Development 6.3	In developing candidate plans, special attention shall be given to ensuring consistency between the IRP and typical rate-making processes. In addition to the ultimate consumer price associated with the plan, the stability of rates and other factors discussed in Section 5.2 need to be considered in any candidate plan selection.	Executive Summary	The IRP provides an evaluation of the potential change in energy costs and customer rates in accordance with the factors set forth in Section 5.2.
61				
62	Proposed Plan Selection 7.1	The Company shall select and file the proposed IRP that is the most consistent with the criteria set forth in 26 Del. C. Sections 1007 and 1020 and this Regulation. The Company shall provide a description of the options recommended for inclusion in the proposed IRP, including a description of the mechanism or process used for valuing each option. The Company shall describe the rationale behind its selection, including any modeling or methodology used as the basis for selection of the proposed IRP.	Executive Summary, Sections 3, 7, and 9.	These requirements are described in various sections of the IRP and the Appendices.

63	Proposed Plan Selection 7.2	The Company shall provide at a minimum a 5 year forecast of supply rates by customer class that would be anticipated based on the IRP planning assumptions and recommended procurement strategy.	Executive Summary and Appendix 5	The forecast of supply rates is provided in Appendix 5. Forecast supply rates for 2015 - 2018 are considered confidential until the completion of the 2015 SOS Auction process.
64				
65	Implementation Plan 8.1	The Company shall file a 5 year action plan outlining the resource decisions intended to implement the IRP.	Executive Summary	Implementation Plans for each planning objective are provided in the Executive Summary.
66	Implementation Plan 8.1.1	This Implementation Plan shall include all actions to be taken in the first 2 years and outline actions anticipated in the last 3 years.	Executive Summary	Implementation Plans for each planning objective are provided in the Executive Summary.
67	Implementation Plan 8.1.2	For IRPs filed on or after December 1, 2010, the Implementation Plan shall include a status report of the specific actions contained in the previous Implementation Plan, including what risk assumptions were made and what actually occurred.	Executive Summary	The Implementation plans for each planning objective include descriptions of relevant milestones that have occurred since the 2012 IRP.
68	Implementation Plan 8.1.3	The Implementation Plan shall include a schedule of key activities related to the IRP implementation	Executive Summary	The Action plans provide the key milestones expected in the next two years.
69				
70	Review and Comment 9.1	Commencing in 2009 and continuing on an annual bases, the Company shall submit a report to the Commission, the Governor, and the General Assembly detailing their progress in implementing their IRPs.		The Company provided a report on the status of the IRP to the Commission, Governor and General Assembly in December, 2013 and will provide a new report on or before December 31, 2014.
71	Review and Comment 9.2	The Commission , interested State Agencies, interested parties and the general public shall be provided an opportunity for review and comment on the Company's IRP filings. The Commission shall seek input from DNREC on the issues of externalities and environmental benefits due to emissions as a result of the IRP.		It is expected that a schedule for public comment on the IRP will be issued after the IRP is filed on December 1, 2014.
72	Review and Comment 9.3	To the extent that the Commission determines that the IRP is not compliant with the statute or is unlikely to meet the goals of the statute, the Company shall revise its IRP to meet these requirements.		As shown in this Appendix, the IRP is compliant with the provisions of 26 Del. C. Sections 1007, 1020 and accompanying regulations.
73	Review and Comment 9.3	Rate treatment in connection with the treatment of future resource acquisitions shall be addressed in rate or other proceedings as filed by the utility or as initiated by the Commission.		The Company will address rate treatment in rate case or other proceedings as appropriate. The IRP does not request any Commission action on rate treatment.
74	Review and Comment 9.4	DPL must maintain sufficient records to permit a review and confirmation of material contained in all required reports as they are subject to annual review and audit by the Commission and interested State Agencies.		All records related to the IRP will be stored and available for inspection and audit as needed.

Appendix 2

Delmarva Power
2014 Integrated Resource Plan
Appendix 2
Responsible Parties – 2014 Integrated Resource Plan (IRP)

Name	IRP Area of Expertise
Jack Barrar	IRP Process
Jaclyn Cantler	Transmission
Kemm Farney	Load Forecast
Pamela Scott	Regulatory and Legal Counsel
Susan DeVito	Customer Rates
Lisa Pfeifer	Environmental
Patrick Augustine[1]	IRP Planning Model
Wayne Hudders	Demand Side Management
William R. Swink	Portfolio Design & Renewables Supply

[1] Pace Global

Appendix 3

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF INTERGRATED RESOURCE PLANNING FOR THE PROVISION OF STANDARD OFFER SERVICE BY DELMARVA POWER & LIGHT COMPANY UNDER 26 *DEL.* C. § 1007 (c) & (d) OPENED DECMEBER 18, 2012	))))))	PSC DOCKET NO. 12-544

ORDER NO. 8574

AND NOW, this 8th day of July, 2014, the Delaware Public Service Commission ("Commission") determines and orders the following:

WHEREAS, 26 *Del. C.* § 1007 (c) (1) requires Delmarva Power & Light Company ("Delmarva" or the "Company") to conduct integrated resource planning; and

WHEREAS, pursuant to 26 *Del. C.* § 1007 (c) (1), Delmarva's Integrated Resource Plan ("IRP") is required to systematically evaluate all available supply options (including procurement, generation, transmission, conservation and load management) over a ten-year planning period, and forecast the appropriate mix of such resources that will be utilized to meet the needs of its Standard Offer Service ("SOS") customers, at minimal cost and without sacrificing adequate reliability; and

WHEREAS, on December 6, 2012, Delmarva filed its IRP pursuant to its statutory obligation; and

WHEREAS, on December 18, 2012, in Order No. 8259, the Commission opened this docket to perform its oversight and review of the IRP, and appointed a Hearing Examiner to make findings and recommendations on Delmarva's proposed IRP; and

WHEREAS, the Commission Staff ("Staff"), the Division of the Public Advocate (the "DPA"), the Delaware Department of Natural Resources and Environmental Control ("DNREC"), the Mid-Atlantic Renewable Energy Coalition ("MAREC"), Sierra Club of Delaware, Calpine and the Caesar Rodney Institute (collectively, the "Parties") intervened or otherwise participated in the proceedings; and

WHEREAS, on March 4, 2013, pursuant to the Parties' request that they be permitted to conduct working group meetings to discuss the IRP, the Hearing Examiner suspended the filing dates for comments required in Order No. 8259; and

WHEREAS, on April 10, May 1, May 14, June 3 and July 31, 2013, the Parties conducted five (5) technical working group meetings regarding the issues raised by various parties, which meetings were publically noticed on the Commission's agenda; and

WHEREAS, pursuant to the schedule established in this Docket, on September 16, 2013, the Parties filed their respective comments on the IRP, and Delmarva filed its responses to those comments on October 16, 2013; and

WHEREAS, subsequently, the Hearing Examiner asked Delmarva to summarize the results of the various working group meetings, which was provided to the Hearing Examiner on April 29, 2014, and along with the Parties' filed comments, was summarized by the Hearing Examiner in his June 2, 2014 Findings of Fact, Conclusions of Law and Recommendations; and

WHEREAS, since no settlement was proposed by the Parties, and the Hearing Examiner assumed that the Parties would make oral

presentations to the Commission, he made no specific recommendations concerning the IRP, concluding only that there was ample evidence that the requirements for public investigation and comment had been satisfied under 26. *Del. Admin. C.* § 3010.9.2; and

WHEREAS, the Commission met in public session on June 26, 2014, to hear the Parties' comments and conduct deliberations on the issues summarized in the Hearing Examiner's Report; and

WHEREAS, Delmarva stated that it had reviewed the comments received from the Staff, DPA, DNREC, CRI, MAREC and Delaware's Sustainable Energy Utility ("SEU") and indicated that it would address those comments, including but not limited to the concern expressed by MAREC and other parties regarding the inclusion of a 15% energy savings goal in the next IRP, which all Parties agreed was not achievable in the immediate future;

NOW, THEREFORE, IT IS ORDERED BY THE AFFIRMATIVE VOTE OF NOT FEWER THAN THREE COMMISSIONERS:

1. The Commission ratifies the IRP appended as Exhibit "A" to the Hearing Examiner's Report, as filed in compliance with the Electric Utility Retail Customer Supply Act of 2006 ("ERUCSA"), 26 *Del. C.* § 1001 *et seq.* and 26 *Del. Admin. C. §3010.*

2. The Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

/s/ Dallas Winslow
Chair

/s/ Joann T. Conaway
Commissioner

/s/ Jaymes B. Lester
Commissioner

/s/ Jeffrey J. Clark
Commissioner

Commissioner

ATTEST:

/s/ Alisa Carrow Bentley
Secretary

Appendix 7

Technical Support Document: -
Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis -
Under Executive Order 12866 -

Interagency Working Group on Social Cost of Carbon, United States Government

With participation by

Council of Economic Advisers
Council on Environmental Quality
Department of Agriculture
Department of Commerce
Department of Energy
Department of Transportation
Environmental Protection Agency
National Economic Council
Office of Management and Budget
Office of Science and Technology Policy
Department of the Treasury

May 2013

Revised July 2015
See Appendix B for Details on Revision

Executive Summary

Under Executive Order 12866, agencies are required, to the extent permitted by law, "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." The purpose of the "social cost of carbon" (SCC) estimates presented here is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

The interagency process that developed the original U.S. government's SCC estimates is described in the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010). Through that process the interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models (IAMs), at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3 percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution.

While acknowledging the continued limitations of the approach taken by the interagency group in 2010, this document provides an update of the SCC estimates based on new versions of each IAM (DICE, PAGE, and FUND). It does not revisit other interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity). Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature.

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD. By way of comparison, the four 2020 SCC estimates reported in the 2010 TSD were $7, $26, $42 and $81 (2007$). The corresponding four updated SCC estimates for 2020 are $12, $43, $64, and $128 (2007$). The model updates that are relevant to the SCC estimates include: an explicit representation of sea level rise damages in the DICE and PAGE models; updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages in the PAGE model; an updated carbon cycle in the DICE model; and updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of methane emissions in the FUND model. The SCC estimates vary by year, and the following table summarizes the revised SCC estimates from 2010 through 2050.

Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

I. Purpose

The purpose of this document is to update the schedule of social cost of carbon (SCC) estimates from the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010).[1] E.O. 13563 commits the Administration to regulatory decision making "based on the best available science."[2] Additionally, the interagency group recommended in 2010 that the SCC estimates be revisited on a regular basis or as model updates that reflect the growing body of scientific and economic knowledge become available.[3] New versions of the three integrated assessment models used by the U.S. government to estimate the SCC (DICE, FUND, and PAGE), are now available and have been published in the peer reviewed literature. While acknowledging the continued limitations of the approach taken by the interagency group in 2010 (documented in the original 2010 TSD), this document provides an update of the SCC estimates based on the latest peer-reviewed version of the models, replacing model versions that were developed up to ten years ago in a rapidly evolving field. It does not revisit other assumptions with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity. Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature. The agencies participating in the interagency working group continue to investigate potential improvements to the way in which economic damages associated with changes in CO_2 emissions are quantified.

Section II summarizes the major updates relevant to SCC estimation that are contained in the new versions of the integrated assessment models released since the 2010 interagency report. Section III presents the updated schedule of SCC estimates for 2010 – 2050 based on these versions of the models. Section IV provides a discussion of other model limitations and research gaps.

II. Summary of Model Updates

This section briefly summarizes changes to the most recent versions of the three integrated assessment models (IAMs) used by the interagency group in 2010. We focus on describing those model updates that are relevant to estimating the social cost of carbon, as summarized in Table 1. For example, both the DICE and PAGE models now include an explicit representation of sea level rise damages. Other revisions to PAGE include: updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages. The DICE model's simple carbon cycle has been updated to be more consistent with a more complex climate model. The FUND model includes updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of

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[1] In this document, we present all values of the SCC as the cost per metric ton of CO_2 emissions. Alternatively, one could report the SCC as the cost per metric ton of carbon emissions. The multiplier for translating between mass of CO_2 and the mass of carbon is 3.67 (the molecular weight of CO_2 divided by the molecular weight of carbon = 44/12 = 3.67).

[2] http://www.whitehouse.gov/sites/default/files/omb/inforeg/eo12866/eo13563_01182011.pdf

[3] See p. 1, 3, 4, 29, and 33 (Interagency Working Group on Social Cost of Carbon 2010).

methane emissions. Changes made to parts of the models that are superseded by the interagency working group's modeling assumptions – regarding equilibrium climate sensitivity, discounting, and socioeconomic variables – are not discussed here but can be found in the references provided in each section below.

Table 1: Summary of Key Model Revisions Relevant to the Interagency SCC

IAM	Version used in 2010 Interagency Analysis	New Version	Key changes relevant to interagency SCC
DICE	2007	2010	Updated calibration of the carbon cycle model and explicit representation of sea level rise (SLR) and associated damages.
FUND	3.5 (2009)	3.8 (2012)	Updated damage functions for space heating, SLR, agricultural impacts, changes to transient response of temperature to buildup of GHG concentrations, and inclusion of indirect climate effects of methane.
PAGE	2002	2009	Explicit representation of SLR damages, revisions to damage function to ensure damages do not exceed 100% of GDP, change in regional scaling of damages, revised treatment of potential abrupt damages, and updated adaptation assumptions.

A. DICE

DICE 2010 includes a number of changes over the previous 2007 version used in the 2010 interagency report. The model changes that are relevant for the SCC estimates developed by the interagency working group include: 1) updated parameter values for the carbon cycle model, 2) an explicit representation of sea level dynamics, and 3) a re-calibrated damage function that includes an explicit representation of economic damages from sea level rise. Changes were also made to other parts of the DICE model—including the equilibrium climate sensitivity parameter, the rate of change of total factor productivity, and the elasticity of the marginal utility of consumption—but these components of DICE are superseded by the interagency working group's assumptions and so will not be discussed here. More details on DICE2007 can be found in Nordhaus (2008) and on DICE2010 in Nordhaus (2010). The DICE2010 model and documentation is also available for download from the homepage of William Nordhaus.

Carbon Cycle Parameters

DICE uses a three-box model of carbon stocks and flows to represent the accumulation and transfer of carbon among the atmosphere, the shallow ocean and terrestrial biosphere, and the deep ocean. These parameters are "calibrated to match the carbon cycle in the Model for the Assessment of Greenhouse Gas Induced Climate Change (MAGICC)" (Nordhaus 2008 p 44).[4] Carbon cycle transfer coefficient values

[4] MAGICC is a simple climate model initially developed by the U.S. National Center for Atmospheric Research that has been used heavily by the Intergovernmental Panel on Climate Change (IPCC) to emulate projections from more sophisticated state of the art earth system simulation models (Randall et al. 2007).

in DICE2010 are based on re-calibration of the model to match the newer 2009 version of MAGICC (Nordhaus 2010 p 2). For example, in DICE2010, in each decade, 12 percent of the carbon in the atmosphere is transferred to the shallow ocean, 4.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 94.8 percent remains in the shallow ocean, and 0.5 percent is transferred to the deep ocean. For comparison, in DICE 2007, 18.9 percent of the carbon in the atmosphere is transferred to the shallow ocean each decade, 9.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 85.3 percent remains in the shallow ocean, and 5 percent is transferred to the deep ocean.

The implication of these changes for DICE2010 is in general a weakening of the ocean as a carbon sink and therefore a higher concentration of carbon in the atmosphere than in DICE2007, for a given path of emissions. All else equal, these changes will generally increase the level of warming and therefore the SCC estimates in DICE2010 relative to those from DICE2007.

Sea Level Dynamics

A new feature of DICE2010 is an explicit representation of the dynamics of the global average sea level anomaly to be used in the updated damage function (discussed below). This section contains a brief description of the sea level rise (SLR) module; a more detailed description can be found on the model developer's website.[5] The average global sea level anomaly is modeled as the sum of four terms that represent contributions from: 1) thermal expansion of the oceans, 2) melting of glaciers and small ice caps, 3) melting of the Greenland ice sheet, and 4) melting of the Antarctic ice sheet.

The parameters of the four components of the SLR module are calibrated to match consensus results from the IPCC's Fourth Assessment Report (AR4).[6] The rise in sea level from thermal expansion in each time period (decade) is 2 percent of the difference between the sea level in the previous period and the long run equilibrium sea level, which is 0.5 meters per degree Celsius (°C) above the average global temperature in 1900. The rise in sea level from the melting of glaciers and small ice caps occurs at a rate of 0.008 meters per decade per °C above the average global temperature in 1900.

The contribution to sea level rise from melting of the Greenland ice sheet is more complex. The equilibrium contribution to SLR is 0 meters for temperature anomalies less than 1 °C and increases linearly from 0 meters to a maximum of 7.3 meters for temperature anomalies between 1 °C and 3.5 °C. The contribution to SLR in each period is proportional to the difference between the previous period's sea level anomaly and the equilibrium sea level anomaly, where the constant of proportionality increases with the temperature anomaly in the current period.

[5] Documentation on the new sea level rise module of DICE is available on William Nordhaus' website at: http://nordhaus.econ.yale.edu/documents/SLR_021910.pdf.

[6] For a review of post-IPCC AR4 research on sea level rise, see Nicholls et al. (2011) and NAS (2011).

The contribution to SLR from the melting of the Antarctic ice sheet is -0.001 meters per decade when the temperature anomaly is below 3 °C and increases linearly between 3 °C and 6 °C to a maximum rate of 0.025 meters per decade at a temperature anomaly of 6 °C.

Re-calibrated Damage Function

Economic damages from climate change in the DICE model are represented by a fractional loss of gross economic output in each period. A portion of the remaining economic output in each period (net of climate change damages) is consumed and the remainder is invested in the physical capital stock to support future economic production, so each period's climate damages will reduce consumption in that period and in all future periods due to the lost investment. The fraction of output in each period that is lost due to climate change impacts is represented as one minus a fraction, which is one divided by a quadratic function of the temperature anomaly, producing a sigmoid ("S"-shaped) function.[7] The loss function in DICE2010 has been expanded by adding a quadratic function of SLR to the quadratic function of temperature. In DICE2010 the temperature anomaly coefficients have been recalibrated to avoid double-counting damages from sea level rise that were implicitly included in these parameters in DICE2007.

The aggregate damages in DICE2010 are illustrated by Nordhaus (2010 p 3), who notes that "...damages in the uncontrolled (baseline) [i.e., reference] case ... in 2095 are $12 trillion, or 2.8 percent of global output, for a global temperature increase of 3.4 °C above 1900 levels." This compares to a loss of 3.2 percent of global output at 3.4 °C in DICE2007. However, in DICE2010, annual damages are lower in most of the early periods of the modeling horizon but higher in later periods than would be calculated using the DICE2007 damage function. Specifically, the percent difference between damages in the base run of DICE2010 and those that would be calculated using the DICE2007 damage function starts at +7 percent in 2005, decreases to a low of -14 percent in 2065, then continuously increases to +20 percent by 2300 (the end of the interagency analysis time horizon), and to +160 percent by the end of the model time horizon in 2595. The large increases in the far future years of the time horizon are due to the permanence associated with damages from sea level rise, along with the assumption that the sea level is projected to continue to rise long after the global average temperature begins to decrease. The changes to the loss function generally decrease the interagency working group SCC estimates slightly given that relative increases in damages in later periods are discounted more heavily, all else equal.

B. FUND

FUND version 3.8 includes a number of changes over the previous version 3.5 (Narita et al. 2010) used in the 2010 interagency report. Documentation supporting FUND and the model's source code for all versions of the model is available from the model authors.[8] Notable changes, due to their impact on the

[7] The model and documentation, including formulas, are available on the author's webpage at http://www.econ.yale.edu/~nordhaus/homepage/RICEmodels.htm.

[8] http://www.fund-model.org/. This report uses version 3.8 of the FUND model, which represents a modest update to the most recent version of the model to appear in the literature (version 3.7) (Anthoff and Tol, 2013). For the purpose of computing the SCC, the relevant changes (between 3.7 to 3.8) are associated with improving

SCC estimates, are adjustments to the space heating, agriculture, and sea level rise damage functions in addition to changes to the temperature response function and the inclusion of indirect effects from methane emissions.[9] We discuss each of these in turn.

Space Heating

In FUND, the damages associated with the change in energy needs for space heating are based on the estimated impact due to one degree of warming. These baseline damages are scaled based on the forecasted temperature anomaly's deviation from the one degree benchmark and adjusted for changes in vulnerability due to economic and energy efficiency growth. In FUND 3.5, the function that scales the base year damages adjusted for vulnerability allows for the possibility that in some simulations the benefits associated with reduced heating needs may be an unbounded convex function of the temperature anomaly. In FUND 3.8, the form of the scaling has been modified to ensure that the function is everywhere concave and that there will exist an upper bound on the benefits a region may receive from reduced space heating needs. The new formulation approaches a value of two in the limit of large temperature anomalies, or in other words, assuming no decrease in vulnerability, the reduced expenditures on space heating at any level of warming will not exceed two times the reductions experienced at one degree of warming. Since the reduced need for space heating represents a benefit of climate change in the model, or a negative damage, this change will increase the estimated SCC. This update accounts for a significant portion of the difference in the expected SCC estimates reported by the two versions of the model when run probabilistically.

Sea Level Rise and Land Loss

The FUND model explicitly includes damages associated with the inundation of dry land due to sea level rise. The amount of land lost within a region is dependent upon the proportion of the coastline being protected by adequate sea walls and the amount of sea level rise. In FUND 3.5 the function defining the potential land lost in a given year due to sea level rise is linear in the rate of sea level rise for that year. This assumption implicitly assumes that all regions are well represented by a homogeneous coastline in length and a constant uniform slope moving inland. In FUND 3.8 the function defining the potential land lost has been changed to be a convex function of sea level rise, thereby assuming that the slope of the shore line increases moving inland. The effect of this change is to typically reduce the vulnerability of some regions to sea level rise based land loss, thereby lowering the expected SCC estimate. [10]

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consistency with IPCC AR4 by adjusting the atmospheric lifetimes of CH4 and N2O and incorporating the indirect forcing effects of CH4, along with making minor stability improvements in the sea wall construction algorithm.

[9] The other damage sectors (water resources, space cooling, land loss, migration, ecosystems, human health, and extreme weather) were not significantly updated.

[10] For stability purposes this report also uses an update to the model which assumes that regional coastal protection measures will be built to protect the most valuable land first, such that the marginal benefits of coastal protection is decreasing in the level of protection following Fankhauser (1995).

Agriculture

In FUND, the damages associated with the agricultural sector are measured as proportional to the sector's value. The fraction is bounded from above by one and is made up of three additive components that represent the effects from carbon fertilization, the rate of temperature change, and the level of the temperature anomaly. In both FUND 3.5 and FUND 3.8, the fraction of the sector's value lost due to the level of the temperature anomaly is modeled as a quadratic function with an intercept of zero. In FUND 3.5, the coefficients of this loss function are modeled as the ratio of two random normal variables. This specification had the potential for unintended extreme behavior as draws from the parameter in the denominator approached zero or went negative. In FUND 3.8, the coefficients are drawn directly from truncated normal distributions so that they remain in the range $[0,\infty)$ and $(-\infty,0]$, respectively, ensuring the correct sign and eliminating the potential for divide by zero errors. The means for the new distributions are set equal to the ratio of the means from the normal distributions used in the previous version. In general the impact of this change has been to decrease the range of the distribution while spreading out the distributions' mass over the remaining range relative to the previous version. The net effect of this change on the SCC estimates is difficult to predict.

Transient Temperature Response

The temperature response model translates changes in global levels of radiative forcing into the current expected temperature anomaly. In FUND, a given year's increase in the temperature anomaly is based on a mean reverting function where the mean equals the equilibrium temperature anomaly that would eventually be reached if that year's level of radiative forcing were sustained. The rate of mean reversion defines the rate at which the transient temperature approaches the equilibrium. In FUND 3.5, the rate of temperature response is defined as a decreasing linear function of equilibrium climate sensitivity to capture the fact that the progressive heat uptake of the deep ocean causes the rate to slow at higher values of the equilibrium climate sensitivity. In FUND 3.8, the rate of temperature response has been updated to a quadratic function of the equilibrium climate sensitivity. This change reduces the sensitivity of the rate of temperature response to the level of the equilibrium climate sensitivity, a relationship first noted by Hansen et al. (1985) based on the heat uptake of the deep ocean. Therefore in FUND 3.8, the temperature response will typically be faster than in the previous version. The overall effect of this change is likely to increase estimates of the SCC as higher temperatures are reached during the timeframe analyzed and as the same damages experienced in the previous version of the model are now experienced earlier and therefore discounted less.

Methane

The IPCC AR4 notes a series of indirect effects of methane emissions, and has developed methods for proxying such effects when computing the global warming potential of methane (Forster et al. 2007). FUND 3.8 now includes the same methods for incorporating the indirect effects of methane emissions. Specifically, the average atmospheric lifetime of methane has been set to 12 years to account for the feedback of methane emissions on its own lifetime. The radiative forcing associated with atmospheric methane has also been increased by 40% to account for its net impact on ozone production and

stratospheric water vapor. All else equal, the effect of this increased radiative forcing will be to increase the estimated SCC values, due to greater projected temperature anomaly.

C. PAGE

PAGE09 (Hope 2013) includes a number of changes from PAGE2002, the version used in the 2010 SCC interagency report. The changes that most directly affect the SCC estimates include: explicitly modeling the impacts from sea level rise, revisions to the damage function to ensure damages are constrained by GDP, a change in the regional scaling of damages, a revised treatment for the probability of a discontinuity within the damage function, and revised assumptions on adaptation. The model also includes revisions to the carbon cycle feedback and the calculation of regional temperatures.[11] More details on PAGE09 can be found in Hope (2011a, 2011b, 2011c). A description of PAGE2002 can be found in Hope (2006).

Sea Level Rise

While PAGE2002 aggregates all damages into two categories – economic and non-economic impacts -, PAGE09 adds a third explicit category: damages from sea level rise. In the previous version of the model, damages from sea level rise were subsumed by the other damage categories. In PAGE09 sea level damages increase less than linearly with sea level under the assumption that land, people, and GDP are more concentrated in low-lying shoreline areas. Damages from the economic and non-economic sector were adjusted to account for the introduction of this new category.

Revised Damage Function to Account for Saturation

In PAGE09, small initial economic and non-economic benefits (negative damages) are modeled for small temperature increases, but all regions eventually experience economic damages from climate change, where damages are the sum of additively separable polynomial functions of temperature and sea level rise. Damages transition from this polynomial function to a logistic path once they exceed a certain proportion of remaining Gross Domestic Product (GDP) to ensure that damages do not exceed 100 percent of GDP. This differs from PAGE2002, which allowed Eastern Europe to potentially experience large benefits from temperature increases, and which also did not bound the possible damages that could be experienced.

Regional Scaling Factors

As in the previous version of PAGE, the PAGE09 model calculates the damages for the European Union (EU) and then, assumes that damages for other regions are proportional based on a given scaling factor. The scaling factor in PAGE09 is based on the length of a region's coastline relative to the EU (Hope 2011b). Because of the long coastline in the EU, other regions are, on average, less vulnerable than the EU for the same sea level and temperature increase, but all regions have a positive scaling factor. PAGE2002 based its scaling factors on four studies reported in the IPCC's third assessment report, and allowed for benefits

[11] Because several changes in the PAGE model are structural (e.g., the addition of sea level rise and treatment of discontinuity), it is not possible to assess the direct impact of each change on the SCC in isolation as done for the other two models above.

from temperature increase in Eastern Europe, smaller impacts in developed countries, and higher damages in developing countries.

Probability of a Discontinuity

In PAGE2002, the damages associated with a "discontinuity" (nonlinear extreme event) were modeled as an expected value. Specifically, a stochastic probability of a discontinuity was multiplied by the damages associated with a discontinuity to obtain an expected value, and this was added to the economic and non-economic impacts. That is, additional damages from an extreme event, such as extreme melting of the Greenland ice sheet, were multiplied by the probability of the event occurring and added to the damage estimate. In PAGE09, the probability of discontinuity is treated as a discrete event for each year in the model. The damages for each model run are estimated either with or without a discontinuity occurring, rather than as an expected value. A large-scale discontinuity becomes possible when the temperature rises beyond some threshold value between 2 and 4°C. The probability that a discontinuity will occur beyond this threshold then increases by between 10 and 30 percent for every 1°C rise in temperature beyond the threshold. If a discontinuity occurs, the EU loses an additional 5 to 25 percent of its GDP (drawn from a triangular distribution with a mean of 15 percent) in addition to other damages, and other regions lose an amount determined by the regional scaling factor. The threshold value for a possible discontinuity is lower than in PAGE2002, while the rate at which the probability of a discontinuity increases with the temperature anomaly and the damages that result from a discontinuity are both higher than in PAGE2002. The model assumes that only one discontinuity can occur and that the impact is phased in over a period of time, but once it occurs, its effect is permanent.

Adaptation

As in PAGE2002, adaptation is available to help mitigate any climate change impacts that occur. In PAGE this adaptation is the same regardless of the temperature change or sea level rise and is therefore akin to what is more commonly considered a reduction in vulnerability. It is modeled by reducing the damages by some percentage. PAGE09 assumes a smaller decrease in vulnerability than the previous version of the model and assumes that it will take longer for this change in vulnerability to be realized. In the aggregated economic sector, at the time of full implementation, this adaptation will mitigate all damages up to a temperature increase of 1°C, and for temperature anomalies between 1°C and 2°C, it will reduce damages by 15-30 percent (depending on the region). However, it takes 20 years to fully implement this adaptation. In PAGE2002, adaptation was assumed to reduce economic sector damages up to 2°C by 50-90 percent after 20 years. Beyond 2°C, no adaptation is assumed to be available to mitigate the impacts of climate change. For the non-economic sector, in PAGE09 adaptation is available to reduce 15 percent of the damages due to a temperature increase between 0°C and 2°C and is assumed to take 40 years to fully implement, instead of 25 percent of the damages over 20 years assumed in PAGE2002. Similarly, adaptation is assumed to alleviate 25-50 percent of the damages from the first 0.20 to 0.25 meters of sea level rise but is assumed to be ineffective thereafter. Hope (2011c) estimates that the less optimistic assumptions regarding the ability to offset impacts of temperature and sea level rise via adaptation increase the SCC by approximately 30 percent.

Other Noteworthy Changes

Two other changes in the model are worth noting. There is a change in the way the model accounts for decreased CO_2 absorption on land and in the ocean as temperature rises. PAGE09 introduces a linear feedback from global mean temperature to the percentage gain in the excess concentration of CO_2, capped at a maximum level. In PAGE2002, an additional amount was added to the CO_2 emissions each period to account for a decrease in ocean absorption and a loss of soil carbon. Also updated is the method by which the average global and annual temperature anomaly is downscaled to determine annual average regional temperature anomalies to be used in the regional damage functions. In PAGE2002, the scaling was determined solely based on regional difference in emissions of sulfate aerosols. In PAGE09, this regional temperature anomaly is further adjusted using an additive factor that is based on the average absolute latitude of a region relative to the area weighted average absolute latitude of the Earth's landmass, to capture relatively greater changes in temperature forecast to be experienced at higher latitudes.

III. Revised SCC Estimates

The updated versions of the three integrated assessment models were run using the same methodology detailed in the 2010 TSD (Interagency Working Group on Social Cost of Carbon 2010). The approach along with the inputs for the socioeconomic emissions scenarios, equilibrium climate sensitivity distribution, and discount rate remains the same. This includes the five reference scenarios based on the EMF-22 modeling exercise, the Roe and Baker equilibrium climate sensitivity distribution calibrated to the IPCC AR4, and three constant discount rates of 2.5, 3, and 5 percent.

As was previously the case, the use of three models, three discount rates, and five scenarios produces 45 separate distributions for the global SCC. The approach laid out in the 2010 TSD applied equal weight to each model and socioeconomic scenario in order to reduce the dimensionality down to three separate distributions representative of the three discount rates. The interagency group selected four values from these distributions for use in regulatory analysis. Three values are based on the average SCC across models and socio-economic-emissions scenarios at the 2.5, 3, and 5 percent discount rates, respectively. The fourth value was chosen to represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution. For this purpose, the 95th percentile of the SCC estimates at a 3 percent discount rate was chosen. (A detailed set of percentiles by model and scenario combination and additional summary statistics for the 2020 values is available in the Appendix.) As noted in the 2010 TSD, "the 3 percent discount rate is the central value, and so the central value that emerges is the average SCC across models at the 3 percent discount rate" (Interagency Working Group on Social Cost of Carbon 2010, p. 25). However, for purposes of capturing the uncertainties involved in regulatory impact analysis, the interagency group emphasizes the importance and value of including all four SCC values.

Table 2 shows the four selected SCC estimates in five year increments from 2010 to 2050. Values for 2010, 2020, 2030, 2040, and 2050 are calculated by first combining all outputs (10,000 estimates per model run) from all scenarios and models for a given discount rate. Values for the years in between are calculated

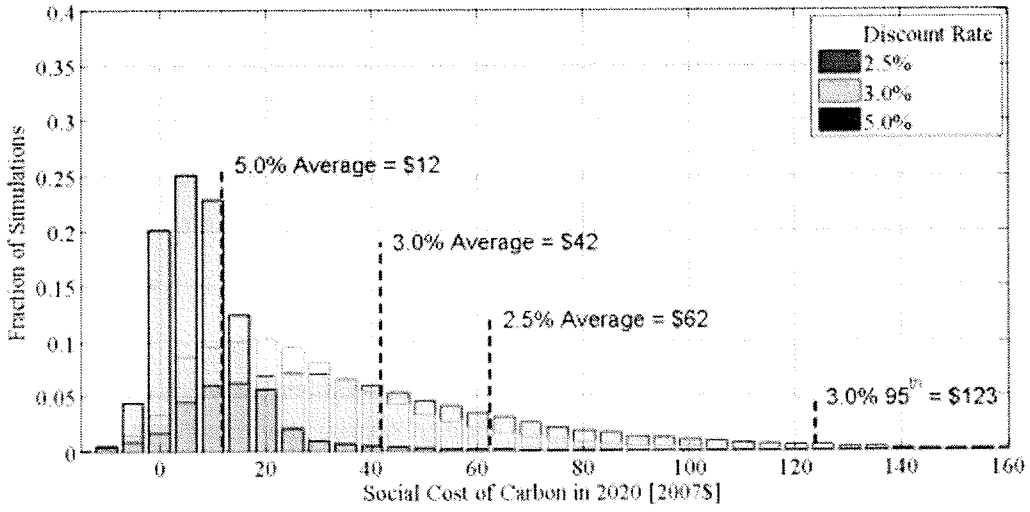
using linear interpolation. The full set of revised annual SCC estimates between 2010 and 2050 is reported in the Appendix.

Table 2: Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD due to the changes to the models outlined in the previous section. By way of comparison, the 2020 SCC estimates reported in the original TSD were $7, $26, $42 and $81 (2007$) (Interagency Working Group on Social Cost of Carbon 2010). Figure 1 illustrates where the four SCC values for 2020 fall within the full distribution for each discount rate based on the combined set of runs for each model and scenario (150,000 estimates in total for each discount rate). In general, the distributions are skewed to the right and have long tails. The Figure also shows that the lower the discount rate, the longer the right tail of the distribution.

Figure 1: Distribution of SCC Estimates for 2020 (in 2007$ per metric ton CO_2)



As was the case in the 2010 TSD, the SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in

response to greater climatic change. The approach taken by the interagency group is to compute the cost of a marginal ton emitted in the future by running the models for a set of perturbation years out to 2050. Table 3 illustrates how the growth rate for these four SCC estimates varies over time.

Table 3: Average Annual Growth Rates of SCC Estimates between 2010 and 2050

Average Annual Growth Rate (%)	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010-2020	1.2%	3.2%	2.4%	4.4%
2020-2030	3.4%	2.1%	1.7%	2.3%
2030-2040	3.0%	1.9%	1.5%	2.0%
2040-2050	2.6%	1.6%	1.3%	1.6%

The future monetized value of emission reductions in each year (the SCC in year *t* multiplied by the change in emissions in year *t*) must be discounted to the present to determine its total net present value for use in regulatory analysis. As previously discussed in the 2010 TSD, damages from future emissions should be discounted at the same rate as that used to calculate the SCC estimates themselves to ensure internal consistency – i.e., future damages from climate change, whether they result from emissions today or emissions in a later year, should be discounted using the same rate.

Under current OMB guidance contained in Circular A-4, analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international perspective is optional. However, the climate change problem is highly unusual in at least two respects. First, it involves a global externality: emissions of most greenhouse gases contribute to damages around the world even when they are emitted in the United States. Consequently, to address the global nature of the problem, the SCC must incorporate the full (global) damages caused by GHG emissions. Second, climate change presents a problem that the United States alone cannot solve. Even if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change. Other countries would also need to take action to reduce emissions if significant changes in the global climate are to be avoided. Emphasizing the need for a global solution to a global problem, the United States has been actively involved in seeking international agreements to reduce emissions and in encouraging other nations, including emerging major economies, to take significant steps to reduce emissions. When these considerations are taken as a whole, the interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable. For additional discussion, see the 2010 TSD.

IV. Other Model Limitations and Research Gaps

The 2010 interagency SCC TSD discusses a number of important limitations for which additional research is needed. In particular, the document highlights the need to improve the quantification of both non-catastrophic and catastrophic damages, the treatment of adaptation and technological change, and the way in which inter-regional and inter-sectoral linkages are modeled. While the new version of the models discussed above offer some improvements in these areas, further work remains warranted. The 2010 TSD also discusses the need to more carefully assess the implications of risk aversion for SCC estimation as

well as the inability to perfectly substitute between climate and non-climate goods at higher temperature increases, both of which have implications for the discount rate used. EPA, DOE, and other agencies continue to engage in research on modeling and valuation of climate impacts that can potentially improve SCC estimation in the future.

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Appendix A

Table A1: Annual SCC Values: 2010-2050 (2007$/metric ton CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2011	11	32	51	90
2012	11	33	53	93
2013	11	34	54	97
2014	11	35	55	101
2015	11	36	56	105
2016	11	38	57	108
2017	11	39	59	112
2018	12	40	60	116
2019	12	41	61	120
2020	12	42	62	123
2021	12	42	63	126
2022	13	43	64	129
2023	13	44	65	132
2024	13	45	66	135
2025	14	46	68	138
2026	14	47	69	141
2027	15	48	70	143
2028	15	49	71	146
2029	15	49	72	149
2030	16	50	73	152
2031	16	51	74	155
2032	17	52	75	158
2033	17	53	76	161
2034	18	54	77	164
2035	18	55	78	168
2036	19	56	79	171
2037	19	57	81	174
2038	20	58	82	177
2039	20	59	83	180
2040	21	60	84	183
2041	21	61	85	186
2042	22	61	86	189
2043	22	62	87	192
2044	23	63	88	194
2045	23	64	89	197
2046	24	65	90	200
2047	24	66	92	203
2048	25	67	93	206
2049	25	68	94	209
2050	26	69	95	212

Table A2: 2020 Global SCC Estimates at 2.5 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario[12]	PAGE									
IMAGE	6	10	15	26	55	123	133	313	493	949
MERGE Optimistic	4	6	8	15	32	75	79	188	304	621
MESSAGE	4	7	10	19	41	104	103	266	463	879
MiniCAM Base	5	8	12	21	45	102	108	255	412	835
5th Scenario	2	4	6	11	24	81	66	192	371	915

Scenario	DICE									
IMAGE	25	31	37	47	64	72	92	123	139	161
MERGE Optimistic	14	18	20	26	36	40	50	65	74	85
MESSAGE	20	24	28	37	51	58	71	95	109	221
MiniCAM Base	20	25	29	38	53	61	76	102	117	135
5th Scenario	17	22	25	33	45	52	65	91	106	126

Scenario	FUND									
IMAGE	-14	-2	4	15	31	39	55	86	107	157
MERGE Optimistic	-6	1	6	14	27	35	46	70	87	141
MESSAGE	-16	-5	1	11	24	31	43	67	83	126
MiniCAM Base	-7	2	7	16	32	39	55	83	103	158
5th Scenario	-29	-13	-6	4	16	21	32	53	69	103

Table A3: 2020 Global SCC Estimates at 3 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	4	7	9	17	36	87	91	228	369	696
MERGE Optimistic	2	4	6	10	22	54	55	136	222	461
MESSAGE	3	5	7	13	28	72	71	188	316	614
MiniCAM Base	3	5	7	13	29	70	72	177	288	597
5th Scenario	1	3	4	7	16	55	46	130	252	632

Scenario	DICE									
IMAGE	16	21	24	32	43	48	60	79	90	102
MERGE Optimistic	10	13	15	19	25	28	35	44	50	58
MESSAGE	14	18	20	26	35	40	49	64	73	83
MiniCAM Base	13	17	20	26	35	39	49	65	73	85
5th Scenario	12	15	17	22	30	34	43	58	67	79

Scenario	FUND									
IMAGE	-13	-4	0	8	18	23	33	51	65	99
MERGE Optimistic	-7	-1	2	8	17	21	29	45	57	95
MESSAGE	-14	-6	-2	5	14	18	26	41	52	82
MiniCAM Base	-7	-1	3	9	19	23	33	50	63	101
5th Scenario	-22	-11	-6	1	8	11	18	31	40	62

[12] See 2010 TSD for a description of these scenarios.

Table A4: 2020 Global SCC Estimates at 5 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	1	2	2	4	10	27	26	68	118	234
MERGE Optimistic	1	1	2	3	6	17	17	43	72	146
MESSAGE	1	1	2	4	8	23	22	58	102	207
MiniCAM Base	1	1	2	3	8	20	20	52	90	182
5th Scenario	0	1	1	2	5	17	14	39	75	199
Scenario	DICE									
IMAGE	6	8	9	11	14	15	18	22	25	27
MERGE Optimistic	4	5	6	7	9	10	12	15	16	18
MESSAGE	6	7	8	10	12	13	16	20	22	25
MiniCAM Base	5	6	7	8	11	12	14	18	20	22
5th Scenario	5	6	6	8	10	11	14	17	19	21
Scenario	FUND									
IMAGE	-9	-5	-4	-1	2	3	6	10	14	24
MERGE Optimistic	-6	-4	-2	0	3	4	6	11	15	26
MESSAGE	-10	-6	-4	-1	1	2	5	9	12	21
MiniCAM Base	-7	-4	-2	0	3	4	6	11	14	25
5th Scenario	-11	-7	-5	-3	0	0	3	5	7	13

Table A5: Additional Summary Statistics of 2020 Global SCC Estimates

Discount rate:	5.0%				3.0%				2.5%			
Statistic:	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis
DICE	12	26	2	15	38	409	3	24	57	1097	3	30
PAGE	21	1481	5	32	68	13712	4	22	97	26878	4	23
FUND	3	41	5	179	19	1452	-42	8727	33	6154	-73	14931

Appendix B

The November 2013 revision of this technical support document is based on two corrections to the runs based on the FUND model. First, the potential dry land loss in the algorithm that estimates regional coastal protections was misspecified in the model's computer code. This correction is covered in an erratum to Anthoff and Tol (2013) published in the same journal (Climatic Change) in October 2013 (Anthoff and Tol (2013b)). Second, the equilibrium climate sensitivity distribution was inadvertently specified as a truncated Gamma distribution (the default in FUND) as opposed to the truncated Roe and Baker distribution as was intended. The truncated Gamma distribution used in the FUND runs had approximately the same mean and upper truncation point, but lower variance and faster decay of the upper tail, as compared to the intended specification based on the Roe and Baker distribution. The difference between the original estimates reported in the May 2013 version of this technical support document and this revision are generally one dollar or less.

The July 2015 revision of this technical support document is based on two corrections. First, the DICE model had been run up to 2300 rather than through 2300, as was intended, thereby leaving out the marginal damages in the last year of the time horizon. Second, due to an indexing error, the results from the PAGE model were in 2008 U.S. dollars rather than 2007 U.S. dollars, as was intended. In the current revision, all models have been run through 2300, and all estimates are in 2007 U.S. dollars. On average the revised SCC estimates are one dollar less than the mean SCC estimates reported in the November 2013 version of this technical support document. The difference between the 95th percentile estimates with a 3% discount rate is slightly larger, as those estimates are heavily influenced by results from the PAGE model.

Appendix 8

U.S. Department of Labor
Bureau of Labor Statistics
Washington, D.C. 20212

Consumer Price Index
Urban Wage Earners and Clerical Workers (CPI-W)
U.S. City Average
All Items
1982-84=100

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg	Percent Change Dec.-Dec.	Percent Change Avg.-Avg.
1990	125.9	126.4	127.1	127.3	127.5	128.3	128.7	129.9	131.1	131.9	132.2	132.2	129.0	6.1	5.2
1991	132.8	132.8	133.0	133.3	133.8	134.1	134.3	134.6	135.2	135.4	135.8	135.9	134.3	2.8	4.1
1992	136.0	136.4	137.0	137.3	137.6	138.1	138.4	138.8	139.1	139.6	139.8	139.8	138.2	2.9	2.9
1993	140.3	140.7	141.1	141.6	141.9	142.0	142.1	142.4	142.6	143.3	143.4	143.3	142.1	2.5	2.8
1994	143.6	144.0	144.4	144.7	144.9	145.4	145.8	146.5	146.9	147.0	147.3	147.2	145.6	2.7	2.5
1995	147.8	148.3	148.7	149.3	149.6	149.9	149.9	150.2	150.6	151.0	150.9	150.9	149.8	2.5	2.9
1996	151.7	152.2	152.9	153.6	154.0	154.1	154.3	154.5	155.1	155.5	155.9	155.9	154.1	3.3	2.9
1997	156.3	156.8	157.0	157.2	157.2	157.4	157.5	157.8	158.3	158.5	158.5	158.2	157.6	1.5	2.3
1998	158.4	158.5	158.7	159.1	159.5	159.7	159.8	160.0	160.2	160.6	160.7	160.7	159.7	1.6	1.3
1999	161.0	161.1	161.4	162.7	162.8	162.8	163.3	163.8	164.7	165.0	165.1	165.1	163.2	2.7	2.2
2000	165.6	166.5	167.9	168.0	168.2	169.2	169.4	169.3	170.4	170.6	170.9	170.7	168.9	3.4	3.5
2001	171.7	172.4	172.6	173.5	174.4	174.6	173.8	173.8	174.8	174.0	173.7	172.9	173.5	1.3	2.7
2002	173.2	173.7	174.7	175.8	175.8	175.9	176.1	176.6	177.0	177.3	177.4	177.0	175.9	2.4	1.4
2003	177.7	179.2	180.3	179.8	179.4	179.6	179.6	180.3	181.0	180.7	180.2	179.9	179.8	1.6	2.2
2004	180.9	181.9	182.9	183.5	184.7	185.3	184.9	185.0	185.4	186.5	186.8	186.0	184.5	3.4	2.6
2005	186.3	187.3	188.6	190.2	190.0	190.1	191.0	192.1	195.0	195.2	193.4	192.5	191.0	3.5	3.5
2006	194.0	194.2	195.3	197.2	198.2	198.6	199.2	199.6	198.4	197.0	196.8	197.2	197.1	2.4	3.2
2007	197.559	198.544	200.612	202.130	203.661	203.906	203.700	203.199	203.889	204.338	205.891	205.777	202.767	4.3	2.9
2008	206.744	207.254	209.147	210.698	212.788	215.223	216.304	215.247	214.935	212.182	207.296	204.813	211.053	-0.5	4.1
2009	205.700	206.708	207.218	207.925	208.774	210.972	210.526	211.156	211.322	211.549	212.003	211.703	209.630	3.4	-0.7
2010	212.568	212.544	213.525	213.958	214.124	213.839	213.898	214.205	214.306	214.623	214.750	215.262	213.967	1.7	2.1
2011	216.400	217.535	220.024	221.743	222.954	222.522	222.686	223.326	223.688	223.043	222.813	222.166	221.575	3.2	3.6
2012	223.216	224.317	226.304	227.012	226.600	226.036	225.568	227.056	228.184	227.974	226.595	225.889	226.229	1.7	2.1
2013	226.520	228.677	229.323	228.949	229.399	230.002	230.084	230.359	230.537	229.735	229.133	229.174	229.324	1.5	1.4
2014	230.040	230.871	232.560	233.443	234.216	234.702	234.525	234.030	234.170	233.229	231.551	229.909	232.771	0.3	1.5
2015	228.294	229.421	231.055	231.520	232.908	233.804	233.806	233.366	232.661	232.373	231.721	230.791	231.810	0.4	-0.4
2016	231.061	230.972	232.209	233.438	(r)234.436	(r)235.289	(r)234.771	(r)234.904	235.495						

(r) Revised.

U.S. Department of Labor
Bureau of Labor Statistics
Washington, D.C. 20212

Consumer Price Index
All Urban Consumers (CPI-U)
U.S. City Average
All Items
1982-84=100

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg	Percent Change Dec.-Dec.	Percent Change Avg.-Avg.
1990	127.4	128.0	128.7	128.9	129.2	129.9	130.4	131.6	132.7	133.5	133.8	133.8	130.7	6.1	5.4
1991	134.6	134.8	135.0	135.2	135.6	136.0	136.2	136.6	137.2	137.4	137.8	137.9	136.2	3.1	4.2
1992	138.1	138.6	139.3	139.5	139.7	140.2	140.5	140.9	141.3	141.8	142.0	141.9	140.3	2.9	3.0
1993	142.6	143.1	143.6	144.0	144.2	144.4	144.4	144.8	145.1	145.7	145.8	145.8	144.5	2.7	3.0
1994	146.2	146.7	147.2	147.4	147.5	148.0	148.4	149.0	149.4	149.5	149.7	149.7	148.2	2.7	2.6
1995	150.3	150.9	151.4	151.9	152.2	152.5	152.5	152.9	153.2	153.7	153.6	153.5	152.4	2.5	2.8
1996	154.4	154.9	155.7	156.3	156.6	156.7	157.0	157.3	157.8	158.3	158.6	158.6	156.9	3.3	3.0
1997	159.1	159.6	160.0	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3	160.5	1.7	2.3
1998	161.6	161.9	162.2	162.5	162.8	163.0	163.2	163.4	163.6	164.0	164.0	163.9	163.0	1.6	1.6
1999	164.3	164.5	165.0	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3	166.6	2.7	2.2
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174.0	174.1	174.0	172.2	3.4	3.4
2001	175.1	175.8	176.2	176.9	177.7	178.0	177.5	177.5	178.3	177.7	177.4	176.7	177.1	1.6	2.8
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181.0	181.3	181.3	180.9	179.9	2.4	1.6
2003	181.7	183.1	184.2	183.8	183.5	183.7	183.9	184.6	185.2	185.0	184.5	184.3	184.0	1.9	2.3
2004	185.2	186.2	187.4	188.0	189.1	189.7	189.4	189.5	189.9	190.9	191.0	190.3	188.9	3.3	2.7
2005	190.7	191.8	193.3	194.6	194.4	194.5	195.4	196.4	198.8	199.2	197.6	196.8	195.3	3.4	3.4
2006	198.3	198.7	199.8	201.5	202.5	202.9	203.5	203.9	202.9	201.8	201.5	201.8	201.6	2.5	3.2
2007	202.416	203.499	205.352	206.686	207.949	208.352	208.299	207.917	208.490	208.936	210.177	210.036	207.342	4.1	2.8
2008	211.080	211.693	213.528	214.823	216.632	218.815	219.964	219.086	218.783	216.573	212.425	210.228	215.303	0.1	3.8
2009	211.143	212.193	212.709	213.240	213.856	215.693	215.351	215.834	215.969	216.177	216.330	215.949	214.537	2.7	-0.4
2010	216.687	216.741	217.631	218.009	218.178	217.965	218.011	218.312	218.439	218.711	218.803	219.179	218.056	1.5	1.6
2011	220.223	221.309	223.467	224.906	225.964	225.722	225.922	226.545	226.889	226.421	226.230	225.672	224.939	3.0	3.2
2012	226.665	227.663	229.392	230.085	229.815	229.478	229.104	230.379	231.407	231.317	230.221	229.601	229.594	1.7	2.1
2013	230.280	232.166	232.773	232.531	232.945	233.504	233.596	233.877	234.149	233.546	233.069	233.049	232.957	1.5	1.5
2014	233.916	234.781	236.293	237.072	237.900	238.343	238.250	237.852	238.031	237.433	236.151	234.812	236.736	0.8	1.6
2015	233.707	234.722	236.119	236.599	237.805	238.638	238.654	238.316	237.945	237.838	237.336	236.525	237.017	0.7	0.1
2016	236.916	237.111	238.132	239.261	(r)240.229	(r)241.018	(r)240.628	(r)240.849	241.428						

(r) Revised.

Appendix 9

Solar jobs in Delaware
Survey results to date
27-Oct-16

	# jobs	avg salaries	
Installers	134	41,390	5,546,260
Electricians	27	49,327	1,331,829
Sales	81	69,004	5,589,324
Clerical	41	41,102	1,685,182
Design/engineers	20	48,004	960,080
Manager/executive	23	99,900	2,297,700
Total	326	58,121	17,410,375
Weighted average salaries			53,406
Jobs serving Delaware	0.78		
	254		
Jobs lost to RPS freeze	143	7,637,066	min.
	146	7,797,285	max.
Original IMPLAN analysis		37,637,711	23,873,110
IMPLAN impact/salaries		1.58	
IMPLAN impact lost jobs		12,040,396	

Appendix 10

Economic Impacts analysis - installation of solar energy systems.

This analysis is based on the survey results provided by the Delaware Department of Natural Resources and Environmental Control. The modeling framework for measuring economic impacts uses input-output modelling. Input-output models give a comprehensive picture of economic activity in a given study region and in our case the State of Delaware. These models provide mathematical relationships that describe the interaction of local industries with each other, with industries outside the region, with households as suppliers of the factors of production and with final users of goods and services. In this particular case the framework used has been developed by the MIG group based on a federal grant. The software and system is called IMPLAN (for Impact Analysis for PLANning) IMPLAN is generally regarded as the most reliable modeling platform. IMPLAN was selected as the analysis framework for monitoring job creation associated with the American Recovery and Reinvestment Act of 2009 which was enacted following the deep economic recession and the *Financial crisis of 2007–08.* The terminology used for describing impacts is as follows

Direct Effect: Under the project-centric approach the direct effects include the jobs and income of local construction workers/installers with the categories specified in the DNREC survey.

Indirect Effect: These occur as businesses buy from other businesses. They are oftentimes referred to as "supply-chain effects". Contractors or installers will purchase for example a variety of goods and services such as installation supplies, solar panels, etc.

Induced effects: These result from the increased income and purchasing power of households who are directly or indirectly affected by expenditures associated with the installation of solar systems. Thus the enhanced income of installers and contractors as they find additional job openings in the construction trades contributes to this effect.

The results of the economic impact analysis are summarized below.

Impact Type	Employment	Total Value Added (contribution to DE GDP)
Direct Effect	300	$23,873,110
Indirect Effect	44	$5,178,946
Induced Effect	104	$8,585,655
Total Effect	448	$37,637,711

The results indicate that the 300 workers employed in the installation of solar systems increases employment in the supply chain by about 44 additional workers and the increased income of the 344 workers produces an induced effect that results in the employment of an additional 104 workers. The

total effect is an employment of 440 workers and a corresponding total contribution of about $38 million to Delaware's Gross domestic product (GDP).

The main industries that are impacted are the following. These can be divided into two categories.

A. Supply Chain industries

Construction of new commercial structures,
Wholesale trade
Real estate
Retail - General merchandise stores
Architectural, engineering, and related services
Truck transportation

B. Induce effect industries i.e. those industries that are impacted by the additional household income generated.

Full-service restaurants
Hospitals
Offices of physicians
Limited-service restaurants – Fast food restaurants.